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WITNESS: SAMUEL S. WATERS

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FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Prudence review to determine regulatory treatment of Tampa Electric Company's Polk Unit.	)))))	Docket No. 960409-EI

DEPOSITION OF:	SAMUEL S. WATERS
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	FPSC Hearing Room 152 Betty Easley Conference Center 4075 Esplanade Way Tallahassee, Florida
TIME:	Commenced at 11:00 a.m. Concluded at 2:30 p.m.
DATE:	Monday, June 10, 1996
REPORTED BY:	Lisa Girod Jones, RPR, RMR

BUREAU OF REPORTING

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ROBERT V. ELIAS, Staff Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850; appearing on behalf of Staff.

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DEPOSITION

Whereupon,

SAMUEL S. WATERS

was called as a witness, having first been duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MR. ELIAS:

Q. Good morning. We are here pursuant to notice for the deposition of Samuel S. Waters. Would you state your name for the record, please.

A. My name is Samuel S. Waters.

Q. And Mr. Waters, by whom are you employed?

A. I'm employed by Florida Power and Light Company.

Q. And how long have you been employed by Florida Power and Light?

A. Approximately 11 years.

Q. Would you describe your educational and work history background before you came to work for Florida Power and Light.

A. T received a four-year degree in engineering from Duke University in 1974. Following my leaving of Duke, I worked for Westinghouse Electric Corporation as a consultant in power system planning for approximately 11 years in Pittsburg. At that time, as I was working, I received a master's degree in electrical engineering from Carnegie Mellon University. In 1985 I moved to Florida and was employed by Florida Power and Light in the system planning department.

Q. And what was your job title when you first went to work for Florida Power and Light Company?

A. When I was first employed by Florida Power and Light Company I was a senior engineer in the planning department.

Q. And would you describe your job duties in the capacity of senior engineer?

A. At that time I was primarily involved in the development of FPL's generation expansion plans, working in the generation planning group doing system studies, not only for generation system expansion, but for cogeneration pricing, conservation and related areas to generation planning.

Q. And how long were you in that position?

A. I was employed in that position for roughly one year. Following that one year I became supervisor of the generation expansion group, still having principally the same duties, but in that job I was responsible for the efforts of a group that developed the generation expansion plan. I served in that role for approximately one year and then became manager of generation expansion planning, roughly one year later.

Q. And that would be in the 1987 time frame?

A. Right.

Q. And as the manager of generation expansion planning, what were your job duties?

A. In addition to development of the generation expansion plan, I also had the responsibility for system studies related to fuel costs, primarily development of the system fuel cost recovery factors. There were related studies dealing with fuel inventory and other fuel issues that were also my responsibility.

Q. And how long did you occupy the position of manager of generation expansion planning?

A. I occupied that position for roughly seven years. The title changed in 1991 to manager of integrated resource planning. I maintained basically the same responsibilities at that time, but also inherited responsibility for the analysis of demand-side management programs that were integrated into FPL's system plans. In that position I remained in system planning until 1994, October of 1994 -- excuse me, October of 1993. At that time I moved to FPL's marketing department where I was director of market planning for approximately four months. In February of '94 I came into my current position as director of regulatory affairs coordination.

Q. Would you describe your current job responsibilities in that position?

A. My current job involves the oversight and coordination of all of Florida Power and Light's regulatory filings at the Florida Public Service Commission and also the Federal Energy Regulatory Commission. Basically the job is to make sure that deadlines are met, that the information provided is complete and accurate, and that FPL's policies are fairly represented in all of the filings.

Q. Now, in your position as manager of generation expansion planning, were you responsible or involved in the determination of FPL's most cost-effective next system resource addition?

A. Yes, I was.

Q. And would you describe what resource addition was planned when you took over in 1987?

A. Well, I'll start, if I may, go back to 1985 when I first joined the Company. At that time the next resource addition was a pulverized coal unit at the Martin site. It was the 1985 study, the system planning study, that I think first changed the projected unit to a combined cycle technology in approximately the 1985 time frame. So in 1987, when I became manager of the group, the plan still called for combined cycle technology. That was still consistently the answer. And by 1988, we recognized that we would have to file for determination of need, which we did in 1989 for that combined cycle technology.

Q. And you described the Martin site, or you mentioned the Martin site. Would you describe that site, as far as how big, what kind of generation is already there and the site specifics?

A. I would have to look. It's a very large site, most of which has been undeveloped or was undeveloped at the time. It consisted at that time of two 800 megawatt class units, oil and gas-fired, large boiler type units. The site is adjacent to Lake Okeechobee. It has a large cooling pond which was developed for an ultimate site capacity up to 4,000 megawatts, depending on the technology and how much cooling is required. But at that time only 1600 megawatts was used. There is gas at the site, natural gas transportation, a pipeline into the site that at that time was used by the 800 megawatt class units. The site beyond that was largely undeveloped at that time.

Q. And you mentioned that the proposed unit addition changed from 1985 to 1987, through 1988 when you began to prepare to file the petition for determination of need. What factors led to the change in choice of most appropriate next unit addition?

A. The answer really began to change in 1985. And I think the principal driver of that was probably technology changes, the availability of new advanced gas turbine technology with higher firing temperatures and higher efficiencies than had been available to that point. At that point gas prices were still projected to be fairly high, certainly much higher than we predict today. But the gas prices in relation to coal prices, and the fact that the technology was available to burn that gas very efficiently, gave us an answer for the first time showing that combined cycles were most cost-effective.

Q. And the coal alternative, was that -- you said that was a pulverized coal facility?

A. Right. That had been the plan prior to 1985.

Q. How large a facility in terms of megawatts was the addition?

A. 800 megawatt class.

Q. And as far as the combined cycle alternative that subsequently Florida Power and Light Company determined to be cost-effective, how large was that facility?

A. The individual units were 400 megawatt class units. And at that time we were looking at two such units at the site. The net rating that we foresaw at that time would have been about 346 megawatts.

Q. And when you say net rating?

A. That's net summer rating, which is the way FPL looks at most of its units, how many megawatts can we get on peak into the system during the summer.

Q. And why summer as opposed to winter?

A. The planning criteria at FPL -- really, one of the criteria, the 15 percent reserve margin, is based on summer peak. The primary reason for that is that most of our loads, approximately 70 percent of our load, is in Dade, Broward and Palm Beach Counties. The winter load there is erratic. We have some years where there is very little winter weather in those three counties. The summer weather, on the other hand, is very predictable, very steady, much more -- much higher occurrence, much higher probability of occurrence. Therefore, we drive our planning needs primarily to meet the summer load.

Q. And you mentioned a 400 megawatt class unit and a net output of 346 megawatts. Is it -- are those units capable of producing more in the winter than in the summer, or --

A. Yes. Gas turbine technology in general will give you more megawatts during the winter.

Q. By approximately what percentage or --

A. Very roughly, it's about ten percent, I would say.

Q. Now, when did FPL file its petition for determination of need for the Martin County units?

A. In 1989.

Q. And at the time, what was the projected cost --

installed cost, for the two 400 megawatt class combined cycle units?

A. If you'll give me just a moment, I'll look. The estimate that we provided at the time for combined cycle technology was -- and this is overnight cost -- was about $533 per kilowatt. The total installed cost we had for the specific project, I believe, was $676 million, and I would have to work backward to a dollar per kilowatt figure, but that included the transmission, on-site transmission and so on, associated with the project.

Q. Did that include the expected escalation and AFUDC that would be incurred during the pendency of the project?

A. Yes, that would be the entire cost.

Q. So that's basically -- if we multiplied that $676 price times the number of kilowatts in the plant, that's the amount that would go into rate base?

A. Other way around. 676 million is the total for the megawatts. That was the amount projected to go into rate base at that time.

Q. What alternatives specifically did FPL consider before determining that the combined cycle units were the most appropriate choice for FPL's next generating alternative?

A. We had in that filing a discussion of, first of all, the demand-side management programs that would be implemented before any capacity was added to the system. So that was the first alternative. We had approximately 1000 megawatts of cogeneration facilities projected in the plan, ahead of any construction. We had power purchases from Southern Company. We had then, when you get into the supply side options that we evaluated versus one another, we had repowering of existing units, we had new gas turbines, the combined cycle technology, the IGCC technology, pulverized coal technology. If I go back one step earlier in the planning process, actually, there were a number of alternatives evaluated beyond that. But those were screened out prior to the economic analysis. So actually there were a large number of alternatives considered, but most, for one reason or another, were screened out early in the process. In some cases it would have been a simple economic screening.

Q. Those alternatives that passed the preliminary economic screening, to the extent that you know, would you describe what has actually happened, in the intervening seven years? For example, how much demand-side management as FPL been able to achieve? How much cogeneration, roughly, was signed up, and power purchases?

A. The numbers have been fairly close to what we've projected at that time. In the cogeneration area, for example, we had projected about a thousand megawatts, and that's roughly where we are.

In demand-side management, it's hard -- a little hard to compare numbers because we have some programs where we talk about total megawatts signed up and some where we have incremental megawatts that were signed up. But, we have implemented to date, I think, over 800 megawatts of load management, for example. And there have been, since that time, several hundred megawatts of conservation programs that have been implemented since the original need filing. So those have been fairly consistent. And of course the power purchases from Southern, the unit power sales, we had defined those at that time. The most recent contract we presented in the '89 filing was a contract we signed in 1988. So those megawatts have been consistent with what we projected.

Q. Now, of the supply side options, would you discuss each of the five that you mentioned, that is, the repowering of other units, the addition of combustion turbines, the IGCC plan and the pulverized coal plan? Why was the combined cycle alternative selected over those alternatives?

A. The combined cycle was selected because it provided the best life cycle economics. In other words, the combination of initial capital costs, operating costs, both fuel and nonfuel, were superior economically to all the other alternatives, with the exception -- and I have to point out -- that part of our '89 filing was the repowering of the Lauderdale units. So one of the repowering options we examined was included in our need filing and did provide favorable economics, even versus combined cycle, new combined cycle units.

Q. Were there other repowering options that were under consideration at the time that have not been pursued?

A. We have consistently over the years looked at other repowering options. The advantage to Lauderdale was that it was a two-unit repowering, which provides better economics. It gives you sort of an economy of scale. The other repowerings we've looked at around the system are related to single units, which don't tend to be as economic.

Q. Were the units that were added, or projected to be added in the need determination filing, for base load, intermediate or peaking capacity needs?

A. Whenever I'm asked this question, I have to back up a little bit. You really don't add units to meet a specific need in my opinion. You look at the economics of the units and how it runs versus what exists on your system, and whatever unit gives you the best economics, you add. In the case of combined cycle, for example, the textbook definition of combined cycle would probably be an intermediate range unit. On our system, because of the existing mix of units and the fuel prices in those units, combined cycles tend to run like base load units. So the Martin units were projected at that time to run at a base load mode.

Q. Would that be a relatively high capacity factor?

A. Yes, neighboring 80 percent.

Q. Did FPL undertake a bidding process or any other kind of -- well, a bidding process, in its selection of how the Martin units were to be constructed?

A. Yes. There's two bidding processes, and I don't want to confuse those. We did -- concurrently with the need filing, we did a request for proposals for capacity in the 1993 to '96 time frame, aimed primarily at the '96 need, which was discussed as a part of the original need filing. Now, having decided then once the determination of need was actually issued and the licensing was complete, yes, FPL did go out for bids on the equipment to construct Martin 3 and 4, as well as a number of the engineering contracts and so on.

Q. Had much of the site development costs for the Martin site been incurred prior to these units being constructed?

A. In the sense that the site was existing and that it had already been laid out for an ultimate site capacity -- for example, the cooling pond and so on -- yes, that was already existing. The pipeline had to be expanded, for example, for this project. So that would have been a cost associated with this particular -- with these units. So you really have a mix. You have some facilities that existed. Some had to be upgraded. Specifically the pipeline capacity and the transmission had to be upgraded for these units.

Q. But in terms of the relative magnitude, is it fair to say that the greater expenses or the greater amount of expenses associated with preparing a, quote, "green field", unquote, site had already been expended?

A. I think that would be fair. Although it would, of course, depend on the site. But a green field site, obviously you would have land acquisition costs and site development costs for just, say, bulldozing the site, that we didn't have.

Q. How long was the pipeline extension that was required to supply these two combined cycle units?

A. It really wasn't a pipeline extension, it was a pipeline expansion. The pipeline existed to the site. So it was a matter of just adding enough capacity to provide the gas supply for those two units. My recollection at the time, we were talking in the neighborhood of 80 million cubic feet a day for the two units, and I think the expansion was a little larger than that, to allow for future capacity additions.

Q. And if you know, was the physical pipeline enlarged, or was it just a case of adding compression to the existing facilities?

A. My recollection is that the pipeline was actually enlarged. There may have been compression additions also, including changes to the main pipeline, which I'm not really familiar with.

Q. Were the costs of that expansion borne by FPL, or someone other than FPL?

A. They were borne by FPL and are included in the cost of the project.

Q. And in order of -- approximately how much did those -- were those costs for the pipeline expansion?

A. I don't recall the precise number. It was really -- the cost for those when we presented the costs were put into a category that included transmission costs also. So I'm not that familiar with the breakdown.

Q. In the aggregate, if you have it, was it categorized as associated facilities or --

A. Yes.

Q. And do you recall approximately what the total for that category was?

A. I recall a number of about $40 million, but I don't recall whether that included off-site transmission as well, and that's the only reason I hesitate. There's a

$44 million figure, but in addition to the on-site work, we had some off-site transmission that had to be upgraded to facilitate getting the megawatts out of the site.

Q. If my information is correct, the Commission order memorializing the decision to grant the determination of need is Order No. 23080 issued June 15th, 1990 in Docket No. 890974-EI. Does that square with your information?

A. Yes.

Q. Okay. Would you describe what activities FPL undertook after the issuance of that order through to the construction and bringing on line of the units, year by year?

A. Okay, the order itself, of course, is only a part of the overall licensing process. So the -- initially, after the issuance of the need determination, the next step was to complete the environmental licensing. And that was necessary before any construction could actually begin. In addition to that, bids were requested for the major components and the engineering work at the site. And that could run concurrently because that didn't involve a commitment of funds. It just involved finding out how much things would cost. Construction, I think, began in earnest in 1991. Site licensing was complete at that point, as I recall.

At that point -- or I should go back and say, up to that point we had received turn-key bids for the units and made the decision, based on those turn-key bids and our own evaluation of what we could do, that we could manage the project ourselves and probably save money over what the turn-key bids had been submitted.

When construction began at that point, it's simply a matter of getting the facilities on site. The gas turbines were installed in '93, as I recall. The site was prepared, and initial foundation work and so on done in '91, '92, gas turbines in in '93. The units game on line in February of '94, and I believe December of '94, from memory. Or excuse me, it was January of '94 and April of '94 actually. It was earlier. We got the units on line ahead of schedule.

Q. Subsequent to the grant of the determination, or the order granting the petition for determination of need, and the actual construction, did FPL perform any cost-effectiveness analyses for the Martin 3 and 4 units?

A. No. There was no event which would initiate such a review, and I don't want to make it sound like we didn't look at the units to see if that needed to be done. The units, of course, were projected to burn gas and run on gas. Given that our fuel forecasts during the entire construction period were lower, one year after the next, we saw a continued dropping in fuel price forecast. We saw a continued dropping of the forecast of the total cost of the unit. Given those circumstances, there was no need to go back and review the cost-effectiveness. That only made a good decision better. And unless there had been some event -- say a dramatic increase in gas prices or a dramatic increase in the projected cost of the units, or some breakthrough in another technology, there would have been no reason to go back and do these analyses.

Q. You mentioned declining fuel price forecasts. Was that across the spectrum of all fuels, or just for gas in particular, or --

A. Primarily gas and oil. Coal tended to remain fairly stable, although that did decline. But coal tends not to be as volatile in price. The gas price changes and oil price changes were rather dramatic over that period as far as dropping from where they had been when we initially made the decision.

Q. When you initially made the decision, was this a close call, or was this project head and shoulders above the alternative?

A. It was -- I guess I would have to describe it as a fairly close call, and of course all things are relative when you're dealing with hundreds of millions of dollars of revenue requirements. But it was fairly close, and for that reason we discussed during the initial licensing possible conversion to coal gasification, should gas prices go the other way from what they actually did. If gas prices had increased, we maintained as an option converting to coal gasification, if that would become necessary.

Q. When you say maintained as an option, was that included in the site certification, or was that something that you just postulated might be appropriate if fuel prices continued -- or if gas prices continued to climb?

A. I believe -- I would actually have to check, but I believe it was included in the site certification. We certainly discussed it at the time of the need hearing. And I know it was presented during environmental licensing as to how the site might be used should we install coal gasification.

Q. And am I correct in concluding that coal gasification was never found to be cost-effective during the construction or subsequent to the need determination for this unit?

A. For these units, that's correct. As long as there was a gas supply, given the forecast of prices that we used during those years, there was never any indication that that would be cost-effective.

Q. And was that a close call in terms of, as you say, hundreds of millions of dollars of revenue requirements or --

A. Well, as time went on it became less and less of a close call because of the drop in the fuel price forecast and the good performance as far as the capital cost on the combined cycles. As those -- as the units became cheaper and fuel was projected to become cheaper, the spread between technologies became greater.

Q. How did the installed cost after the units were completed compare to the 1989 time frame projections?

A. The number we originally estimated, as I mentioned, was 676 million. The current dollars closed out on the project total roughly 511 million. And there are some -- still some open accounts for, you know, cleaning up the site and so on, but it's small dollars. So I would say that's pretty close to a final number right now.

Q. Now, did that change occur as a -- what caused those changes?

A. I would like to say, for the record, it was just good management, but I'm sure there were a number of reasons. Management was certainly part of it. We changed from a traditional approach, which we had used in the past where a lot of design changes were made as the unit was in progress and so on. We basically decided up front we would keep our hands off the unit and not make design changes in the middle, which tend to be very expensive. So a lot of things were done in the project management in an attempt to cut down the cost of the units. And I would have to say that was probably the largest reason. I don't think that the hardware accounted for the largest portion, although that -- I think we probably got some favorable costs, even in the hardware. But I think most of it just comes down to the project management.

Q. Is that $511 million figure, that's for both 400 megawatt class combined cycle units?

A. That's right.

Q. So that would represent an installed cost of approximately $625 a kW?

A. Well, the other thing that happened, which we haven't talked so much about, is that the units -- in 1989 when we were looking to build these units, it was a new technology. It was what we now know as the GE-7F gas turbine technology. That, at the time, had not been installed anywhere, and it was a little bit uncertain as to what the final performance characteristics would be. We projected in the need filing 385 megawatts for each unit, again a summer net rating in 1989. The ratings we have on the units right now, summer net, are 430 megawatts apiece. So it turned out, in addition to the favorable costs, the units have provided more power than we originally forecast.

Q. So then that would make the price something less than $600 per kW installed?

A. Right.

Q. For your deposition, you were asked to bring certain documents with you reflecting cost-effectiveness evaluations and actual costs of the unit.

A. Right.

Q. Do you have those documents with you?

A. Yes. For the cost-effectiveness I brought our original need filing documents, because that was the last time a detailed analysis was actually done for the unit. Then I also have the documents related to the cost.

Q. I would like to ask that they be marked as Deposition Exhibits 1 and 2, the first being the Need Determination, and the second, Cost-effectiveness on the Installed Cost.

(Exhibit Nos. 1 and 2 marked for identification.)

BY MR. ELIAS:

Q. I notice that on this chart Unit 3 is approximately 50 to $60 million more expensive at 253 million versus Unit 4 at 195 million. Why is that?

A. In general the first -- there are costs that get associated with the first unit that are not, say, allocated equally to the second unit later on. When you lay the foundation, the initial labor work, the setup of the site and so on, a lot of that cost gets attributed to the first unit. It's not quite this straightforward, but when the second unit comes in, it's sort of a drop-in to the site. Most of the work to set up has been done. So you would see -- at most two-unit sites you would see the costs allocated that way.

Q. Were they built at the same time?

A. There was a staggered construction schedule. They can't really be built at the same time because you can't have, for instance, four gas turbines all delivered to the site at the same time. So there's a slight staggering of the schedules, so that Unit 3 goes in ahead of Unit 4.

Q. These particular units, would you describe how they're configured?

A. Each unit is a, roughly, 400 megawatt class combined cycle consisting of two gas turbines. In this case they're General Electric Frame 7F gas turbines. I'm trying to remember the configuration, whether it involves two heat recovery steam generators or one. The initial design called for one, but I think the final design called for two. I would have to go back and look at that. As far as from a planning perspective, it didn't make any difference in the performance of the unit, but anyway, there is heat recovery steam generator capacity following the gas turbine. Then followed by one electric generator, which produces -- steam driven generator which produces additional megawatts, to get to the total of 400 and some megawatts.

Q. So are there two heat --

A. There are two gas turbines, one steam turbine, one electric steam turbine. And the only question is, do you use two heat recovery steam generators in between to make the steam, or one? And I can't remember where we ended up.

Q. But two turbines at the end, one for each unit?

A. Two -- yes, there are a total of four gas turbines, two steam turbines for the two units that are on the site.

Q. You had mentioned that the Martin site was a fairly large facility. In terms of approximate acres, do you have that information?

A. I think if you give me just a minute, I think I can find that. I hope. Okay, Martin site is listed in the '96 site plan as 11,179 acres.

Q. And you had said previously that that was depending on fuel type and storage requirements capable -- and cooling requirements capable of supporting 4,000 megawatts?

A. That was the original plan, that's correct.

Q. Since the units went into service, has FPL evaluated the possibility of adding gasification to those units or in its next unit additions at that site?

A. As far as converting those units to gasification, no, because the fuel price forecast doesn't justify it. And we have not seen, at this point, a similar decline in the cost of IGCC units, as we have in the combined cycle. As far as beyond that capability, since those units have been put in service, we have evaluated IGCC technology. What we have seen, probably primarily due to the competitive marketplace, is that pulverized coal units seem to be coming down in price quite a bit from what we had originally estimated. So our next addition might possibly be a pulverized coal unit. I think that's more likely now than the IGCC technology at the moment, but there's nothing that suggests that IGCC technology wouldn't share similar cost reductions through some experience with the technology. But the site -- it's very possible that we could add it at the site. Right now our next additions, though, are gas fired, beyond Martin 3 and 4. They're planned to be gas fired.

Q. And would you describe the next planned unit additions?

A. The next planned unit additions, which we listed in the site plan, is in the year 2004, which we have referred to as Martin Units 5 and 6. They would be combined cycle technology, similar to but really next generation to what is there now. There is another generation of turbines coming forth now, even beyond the 7F technology, and that's what we're currently looking at.

Q. G series?

A. I think they call it the G series. I'm never sure. It's kind of like the chip names, with the Pentium and all the other things. I think it's a G series.

Q. And in terms of the size of those units, how do they compare?

A. They're larger. They tend to be rated upwards of 200 megawatts apiece, and they're more efficient than the 7Fs, obviously, which is the aim of the designers, is to make them more efficient.

Q. After the Commission approved the need for the Martin 3 and 4 units, what other resource additions did FPL pursue?

A. Well, each year -- I'll describe, if I may, a little bit of the process. Each year we reevaluate the need for capacity. And that would include looking at the need for the units themselves, Martin 3 and 4. Beyond Martin 3 and 4, we had originally proposed in our '89 need filing an IGCC, and at that time, concurrent with the need filing, we had issued a request for proposals for capacity.

Out of that request for proposal process, we acquired the Scherer 4 unit from Georgia Power and subsequently submitted that purchase to the Commission for approval. That took care of the '96 need, or was aimed at a 1996 need. Subsequent to that, we, through what I'll call a limited RFP process, contracted with parties to provide a unit that was referred to as the Cypress Energy Project, roughly 800 megawatts of capacity in 1998. That project was submitted to the Commission and the need determination was denied in that particular case.

Q. Let's go back to the Scherer unit addition, and would you describe in some greater detail how that transaction came about? How did FPL learn of the availability of this unit?

A. The process, the RFP process, received a large number of bids from a large number of sources, one of which was Southern Company and Georgia Power's Scherer unit in a unit power sale configuration.

Q. What does a unit power sale configuration mean?

A. It's basically a lease, where we would have the rights to the power output of the unit for a specific number of years, in this case roughly 20 to 30 years, depending on the term we would sign up for. But it is just like that, it's like leasing a car. While we pay the costs associated with the unit during that term and receive the power from it, when the lease is over the unit returns to ownership of the party that was doing the leasing.

We identified that Scherer UPS configuration as the most cost-effective of the bids that had been submitted as part of our RFP process. It was through our discussions with Southern about that proposal that we became aware of the potential for purchasing the unit. And given that that was already the best alternative, the UPS configuration, we decided that there were some additional advantages to purchasing, and we pursued that, and ultimately that's what we did with the unit, was purchase it. As part of that unit, we not only took ownership of part of the unit, as did JEA, in the course of time, also took a part of the unit. We received some emission allowances as part of the purchase and facilitated settlement of the transmission allocation interface -- interface allocation at the state border as part of that deal.

Q. Allocation between?

A. JEA, Florida Power and Light, Florida Power Corporation and Tallahassee.

Q. What was the issue there?

A. There was an identified interface limit of -- at that time I believe it was 3200 megawatts -- that could be imported into the state, and the question was who owned how much of that 3200 megawatts. It was an issue that had moved towards resolution prior to the deal, but there was some discussion between FPL and JEA where we have joint ownership of transmission facilities as to how many megawatts each had rights to. And as part of this overall Scherer agreement, we were able to reach agreement also on that.

Q. And would you describe the Scherer unit, what it is and how big and --

A. The Scherer unit is about an 850 megawatt coal unit, located in Georgia. It's part of a four-unit site in Georgia, all coal units. I guess the technology is unscrubbed coal, primarily from eastern sources at that time is what it burned.

Q. And why wasn't Georgia Power utilizing that unit or didn't plan to utilize the unit?

A. As I recall -- this really goes back to the early eighties, which is before I was in planning. But as I recall, there are certainly certain units within the Southern Company system -- Georgia has Scherer, Alabama has the Miller units and so on -- that were not allowed rate base recovery by their respective commissions. Georgia Power, Alabama Power, the other operating companies of Southern that were basically stuck with this capacity, looked to market those, and we began taking capacity in the early eighties from those units under a unit power sale agreement. So basically it was uncovered capacity that was sold already to FPL on a lease basis, this UPS agreement. With the termination of those leases from those early contracts, the unit became available for sale or subsequent lease deal.

Q. Did FPL purchase all of the 850 megawatts of Scherer Unit 4?

A. No. FPL purchased, at that time, based on the rating of the unit, we purchased 646 megawatts and JEA purchased 200. Our purchase was done in stages. It was not all transferred at the same time. There were roughly three closings, as I recall, to get to the ultimate capacity by 1995 of 646 megawatts for FPL.

Q. And at the time FPL petitioned the Commission to approve this purchase and include the costs in rate base, had a final purchase price been agreed to?

A. We did not have a signed contract, but it was felt that the price, the letter of intent and other documents that were submitted to the Commission were sufficient to make a judgment that the deal was -- and the price was certain.

Q. And as compared to the numbers that appear in Order No. 24165, which is the order granting Florida Power and Light Company's petition to include the Scherer Unit No. 4 purchase in rate base, including acquisition adjustment, how did the eventual final numbers compare?

A. Well, I think the cost, the final numbers, are pretty much exact as to what we had submitted in that the unit was constructed already, the costs were known. This did not involve any new construction or any new facilities. So the costs we were working with were the actual book costs of the unit.

Q. So then the purchase price of $615 million, approximately, is what was eventually paid? And I'm looking at Page 2 of the order.

A. I believe that's correct, yes.

Q. So that is something less than $1,000 a kilowatt, approximately 900?

A. $952 a kilowatt.

Q. I just want to clarify something. You had mentioned that FPL was purchasing unit power sales from this facility before finalizing this agreement?

A. That's correct, as part of an overall agreement with Southern Company that provided roughly 2,000 megawatts of UPS capacity to FPL. The Scherer 4 unit was included, as were a number of others, in providing that power. The fraction of the unit that was included in the 2,000 varied from year to year.

Q. And you also mentioned that at the time you thought that the unit's output -- your share of the unit's output would be 646 megawatts. Has that changed over time?

A. It changes only very slightly. Each year Southern evaluates its units and puts a rating on the units, and we own really a percentage of the unit. So it may go up by one or two megawatts, but it's on that order of magnitude as far as changes.

Q. How do the costs of transporting coal and burning it in Florida compare to the costs of generating electricity in Georgia and transmitting it over the transmission grid?

A. There are so many variables in that question I'm not sure I can give you an answer. For example, Scherer right now is burning more western coal, the Powder River Basin type coal, which is very, very inexpensive. And even with the transportation it's much lower cost than what had been burned there, which was eastern coal. When you do that, it's cheaper to burn it in Georgia and transmit it here, assuming that you can't do that in Florida. Now it's entirely possible that you could have a facility in Florida that could do the same thing. And it's difficult to say whether the transportation costs would offset the transmission costs. I really don't know. That would have to be looked at on a case-by-case basis.

Q. What are some of the variables that would impact that decision?

A. You would have to have a very similar facility, with similar heat rates, similar performance characteristics and so on, to make that kind of judgment. And I don't think we have anything in Florida that's quite comparable to the Scherer unit. Assuming that facility existed in Florida, you could do a nice one-on-one comparison between shipping the coal there versus shipping the coal to the facility in Florida and take the transportation differential and evaluate that versus the losses involved in transmission. But beyond that, we don't have that situation, and therefore it's very hard to judge.

Q. You mentioned that after the Scherer purchase, FPL sought to enter into an agreement with -- I believe you said it was Cypress Energy Partners?

A. Right.

Q. And would you describe that transaction?

A. That was for roughly 800 megawatts of capacity, for two 400 megawatt class coal units that would have been constructed near Lake Okeechobee and then the entire output of that facility would have been provided to FPL under a firm contract. And I believe it was a 30-year contract. And also one thing I should correct, I misspoke before when I said the need determination was turned down. The Commission found that we had a need for capacity, but that the Cypress project was not the most cost-effective alternative available.

Q. What type technology was the Cypress project to utilize?

A. They were to be pulverized coal units very similar to what Orlando has in its Stanton units, very similar type units.

Q. And did the Commission determine that a particular type of technology was more cost-effective or --

A. In the order, I believe it addresses combined cycle units that were offered up by intervenors during the course of the hearing. And there is a comparison between those combined cycle units running on natural gas with the pulverized coal units that were offered by Cypress. And the contention was at that time that those combined cycle units could be operated more cheaply and provide better economics than the Cypress units.

Q. And you don't share that perspective?

A. In hindsight, I can say that was probably a good decision. At the time I felt like the numbers that were offered by the intervenors were more than a little loose. There was no real offering of any kind of fuel arrangements at all. There was simply an assertion that the price would be X. And we felt, and I still feel, that that is not sufficient to really do long term economics; that simply because somebody says you can get gas at a certain price that that's good enough for analysis.

Q. Did FPL ever construct a generating alternative to meet the need that was identified in the Cypress matter?

A. No. Subsequent to that hearing, a number of things happened, some of which we discussed at the hearing and some occurred later. One that we discussed at the hearing was the fact that Seminole Electric, after we had filed that petition, notified FPL that they would -- had intended to discontinue approximately 400 megawatts of load that we were serving, as of 1999. That, of course, decreased the need we were aiming to serve with the unit. At that time, during the hearing, we discussed it and stated that it was not a foregone conclusion at that time. We were still in negotiations with Seminole. Of course subsequent to that hearing they actually did terminate the service for 1999. So that dropped our load requirements by roughly 400 megawatts. Actually less than that, equivalently, when you look at reliability impact, but it did have an impact of decreasing the need.

In addition to that, a number of things happened. We have been able to, through our overhaul process, increase the size of many of our units.

Q. Would you explain that?

A. What is happening at many of the turbines, as they are overhauled, in the course of normal maintenance, we have found that through replacing the blades in some of the turbines, for example, we can incrementally receive up to, say, ten megawatts from a given unit. It's generally small increments, but since most of our units are very similar, we've been able to get probably 100 or more megawatts out of those types of enhancements.

The other thing we looked at doing subsequent to Cypress was using the peaking capability of our boiler-fired units. Basically that's a capability that was always there in the unit. There is a continuous rating of a unit, which is what we normally had used for planning to that time. Then there are peaking ratings, which basically means you push them a little harder, get a few extra megawatts. And there are anywhere from 400 to a thousand megawatts of capability there, depending on how hard you want to push the units. Again, through the course of normal overhauls, we began to feel that we could use the peaking capability on a regular basis and rely on it, and that it would not lead to any degradation in the performance of the units in the long term. So we began to count on that capacity, in the neighborhood of 3- to 400 megawatts.

Beyond those changes, there, of course, were changes to our DSM plans, accelerating some of our demand-side management and so on. And the sum total of all these changes is that we were able to deal with the load forecast in 1998 without the need for any new generating units.

Q. Were there any other significant changes to the market for power generation as a whole during this time frame?

A. The most significant change, which is still ongoing, is the amount of competition in the generation market. Part of that was certainly fostered by FPL's, and others', issuance of request for proposals in the late eighties, early nineties. That brought a lot of competitors to Florida, people interested in building generation. The net effect of competition has been to drive the prices down. In our own estimating, and certainly in the prices that we see bid to us, the prices have lowered over time.

Q. And has that been more or less constant, or can you pick particular points where particular events cause the prices to become lower?

A. I really think it's been ongoing. Certainly the beginning of competition in Florida by issuing RFPs, I guess you could say it sends sort of a wake-up call when you see the prices that you are quoted for firm capacity and then evaluate those bids and determine they are in fact feasible, it makes you take a look at your own process and your own costs. And what I have seen since that time is really an ongoing effort on our part -- and I'm sure it's taking place in other areas too -- to drive the cost down of new construction, find ways to do it a little bit cheaper and a little bit better. So each year we've seen a decline in cost estimates for new units that we would build, even beyond what the market is doing.

Q. Does FPL actively monitor the costs of various types of generation on an ongoing basis, construction?

A. Yes.

Q. And what types of generation do you monitor?

A. The main types of construction going on right now are basically gas-fired. So I would say the large majority of monitoring deals with combined cycle technology, gas turbine technology. I don't think there are too many even pulverized coal units being built at the moment. But as units are built, even if it's, for instance, fluidized bed, which some of the independent power producers are building, or all the gas technologies, we're certainly actively monitoring those and trying to find ways, in looking at those, to lower our costs when we manage a project.

Q. Why aren't coal units being built the way combined cycle units are?

A. For the most part it's just been the decline -- two reasons that we talked about earlier, that we found, the improvement in efficiency of gas-fired units and the lowering of gas price forecast. There's, I think, an increased comfort level with natural gas as a fuel which didn't exist in a large part of the eighties because of the volatility of the fuel price market. But now the gas prices have dropped. There's increasing confidence that they will stay low, and I think a lot of people are looking at that, at least in the near term, to construct units.

Q. How have the changes that you've seen generally to the price of -- or projected price for natural gas, affected

FPL's fuel price forecasting?

A. I guess not being a forecaster, it's probably easier for me to say, but it seems the forecasts always respond to whatever is happening at a particular point in time. From 1990 through 1996, every year we saw a drop in the fuel price forecast for gas from the previous year. And oil, of course, would be the same. And gas is probably the most important fuel to us here as far as adding new construction.

Q. Is the same trend evident for coal?

A. I really haven't looked at coal that much, but even if it had followed for coal, the drop wouldn't be as dramatic, because coal prices tend to not be as volatile. So the drop over time that would have occurred probably would not be the same order of magnitude that we've seen on gas.

Q. Have you as a generation planner evaluated the viability of a fuel called petroleum coke in substitution for coal applications?

A. It's being looked at now at FPL. So I haven't seen it in the planning process yet to -- as far as a large-scale use, but it's certainly being evaluated for specific applications.

Q. And is that existing? I don't want you to give something away here, but is that for existing applications or existing facilities, or potentially new facilities, or both?

A. Primarily new facilities. FPL doesn't have a lot of existing coal-fired capacity on its system, so it's been primarily new facilities.

Q. Other than the Indiantown cogeneration facility and the Scherer Unit 4, are there other coal-fired units on FPL's system?

A. St. Johns. We're partial owners of the St. Johns River Power Park units.

Q. Mr. Waters, you were also asked to bring with you some documents reflecting Florida Power and Light's fuel price forecasts. Have you brought those with you?

A. Yes.

Q. I would ask that they be marked as the next exhibit.

(Exhibit No. 3 marked for identification.)

BY MR. ELIAS:

Q. And I notice you've got a cover sheet here titled Comparison of Natural Gas Price Forecast.

A. Yes.

Q. And just in looking at it very quickly, that appears to represent in chart form what we have spoken of in terms of the prices for natural gas.

A. Right. It basically takes the average delivered price of gas to FPL's system in a given year's forecast and graphs that number. That's what that represents.

Q. Besides the Martin Units, the 3 and 4, what other natural gas-fired units does FPL have on its system?

A. There are a large number of units capable of burning natural gas on FPL's system. In fact, most of FPL's units, with the exception of those on the west coast, can utilize gas. The ones that predominantly use the gas, in addition to Martin 3 and 4, would be the repowered units at Lauderdale, which are really combined cycle units. It's just that they started with existing units rather than being built from scratch. FPL's Cutler unit runs primarily on gas, and FPL's Putnam combined cycle unit runs primarily on gas.

In addition to those units, the Turkey Point Fossil units, the Port Everglades units, the Martin Units, the boiler-fired units at Martin, each of those units is capable of using gas to the extent that it's available and economic to do so, all the way up to Sanford, really all the way up the east coast. We have the capability of switching between oil and gas in most of our boiler-fired units.

Q. How long has FPL been burning natural gas in any of these units? When was the first natural gas on FPL's system, if you know?

A. I really don't know. I mean it goes back to certainly the eighties when I came on board. We were looking at converting units to gas to take advantage of the economics.

Q. When did FPL first acquire natural gas transmission capacity from Florida Gas Transmission?

A. My recollection is that our first agreement for major volumes of gas was around 1987. And then in 1990, when the Federal Energy Regulatory Commission basically changed the structure of the gas industry, we recontracted and renominated for significant volumes at that time and began to take gas on a firm basis. I think prior to that time, most of the gas was probably received on an interruptible basis.

Q. What kind of capacity arrangements for gas transmission did FPL make with Florida gas transmission for Martin Units 3 and 4?

A. We didn't really make specific arrangements for Martin 3 and 4. Our gas usage tends to be a system gas usage. So our capacity that we've arranged through Florida gas transmission looked at the total volume of gas we would use across the system. Of that total volume, the Martin Units might be expected to use something like 80 million cubic feet per day, but the total volumes that we're getting vary seasonally between -- at that time varied seasonally between 280 million cubic feet and 430 million cubic feet.

But that was used system wide. And we've entered into subsequent contracts even beyond that since.

Q. And are those firm?

A. Firm transportation. The supply today is roughly -- I would say 60 to 70 percent firm. It's more than enough to run the units that require gas, with additional gas being available for other units, primarily on an interruptible basis, but since they can burn oil, there's no reliability impact. It's simply a matter of economics.

Q. Does FPL ever release -- let me back up. You mentioned that contracting for gas has changed over the last ten to 15 years. Are you aware of the ruling of the Federal Energy Regulatory Commission that's come to be known as FERC Order 636?

A. Yes.

Q. Would you describe what you know that to be?

A. It basically -- I guess the reason I'm aware of it is because it's so often related to what's going in the electric industry and FERC Order 888, which doesn't go quite that far, but basically it restructures the industry, the gas industry, separating the transportation supplier from the end seller. And prior to that time, gas had been bought in sort of a bundled configuration.

Q. And would you describe how that market now works?

A. The market now allows for FPL, for example, or any user, to go contract for transportation, gas transportation, and then separately contract for sources of supply. We can go directly to the supplier and make our own deal for gas supply. And one of the other things is it also allows, to a certain degree, some -- I believe some buying and reselling of capacity on the pipeline.

Q. Has FPL engaged in the selling or buying and the reselling and buying of capacity on the pipeline?

A. I believe that we have. It's in very small quantities. It represents a very small fraction of our overall capability. And it's only when it's economic, when we have gas supply available to us and it's more economic to sell it, more economic to sell it than it is to burn it on our system, which would be a very limited circumstance. Most of the time we're going to burn the gas that's available to us.

Q. Have there ever been circumstances, if you're aware, where -- has FPL ever released capacity, transportation capacity, that it had previously contracted for?

A. I'm not aware of any specific circumstance where we have done that. It's possible, but I'm not aware of any.

Q. Could I have the last question read back please?

(Record read.)

BY MR. ELIAS:

Q. By releasing capacity into the secondary market, would FPL be able to recoup some of the costs of firm transportation previously committed to?

A. I would think that would be the only circumstance where we would actually do that.

Q. Now, your area, at the time that you were the manager of integrated resource planning, how was the responsibility for fuel price forecasting handled? Was that within your group or was that an input to your efforts?

A. It was not handled within our group. It was done within a group associated with our power generation business unit, which is the power plant group. They're also responsible for acquiring the fuel. So that's where the forecasts were done. In recent years, the original forecast has come from DRI. It's then modified by our people to reflect transportation costs into Florida and so on, but it starts with a DRI forecast.

Q. And who, specifically, within the organization is responsible for developing the fuel price forecast for '91 through '95?

A. The area of responsibility would have fallen under Mr. Rene Silva, I think, for probably that entire period.

Q. And with respect to the combined cycle units, Martin 3 and 4 that we previously discussed, how did the fuels department interact with the generation expansion planners in determining that that was the most appropriate unit choice?

A. In FPL's planning process, there are a number of departments involved, one of which is the fuels department. The way they interact is at the beginning of each planning cycle, taking place in the first quarter of the year, the planning department would request of them a long-term forecast to be used for planning purposes. And of course over the course of time they're familiar with what this request means and what it is we're looking for. But they would develop that forecast, and that would be used as an input to the planning process, very much like the load forecast and a number of other forecasts that are derived for planning.

Q. Other than natural gas, are the Martin combined cycle units capable of burning any other fuels?

A. Yes. They, as a backup fuel, have the capability of burning distillate fuel oil.

Q. And how is distillate fuel oil delivered to the units? Is it --

A. I believe it's trucked in. There was a discussion of having pipeline capability into that site, but I believe it's trucked in. And we would anticipate very, very few hours a year that this would actually be necessary.

Q. Would you agree that over the last five years, that coal and natural gas have maintained an approximately constant differential during that time period?

A. Looked at on an annual basis, I would say that's probably true. There's been quite a bit of volatility, especially lately in the gas market, but over the long term, in looking at an annual number, I would say that's probably about right.

Q. This is probably beyond what you have ready knowledge of, but do you keep abreast of FPL's fuel inventory positions at its various plants?

A. No, I don't.

Q. Do you know what the target coal inventory levels would be at a particular point?

A. Not from memory, no.

MR. ELIAS: Those are all the questions we have. It would be our intent to get copies made of the previously identified deposition exhibits and include them with the deposition as well.

MR. HOWE: I've got a few questions. Does anybody want to break for lunch or continue?

MR. CHILDS: I would like a brief break. I don't know how many --

THE WITNESS: Brief is fine.

MR. CHILDS: I don't know how many more questions there are or how much time.

MR. HOWE: I assume I would take about an hour.

MR. CHILDS: Three questions, huh?

MR. HOWE: With short answers about an hour.

MR. LONG: I have about an hour, hour and a half.

THE WITNESS: I would just as soon take a brief break and come back, since I have a 3:20 flight. I would like to try and make it.

(Brief recess)

EXAMINATION

BY MR. HOWE:

Q. Hello, Mr. Waters.

A. Good afternoon.

Q. I would like to follow up with a couple questions I jotted down while Mr. Elias was asking you questions. One is, I understood you to state that Martin Units 3 and 4 use GE-7F technology for those combustion turbines; is that correct?

A. That's correct.

Q. And am I correct that you have -- at each of the units, Martin 3 and Martin 4, individual units are comprised of two GE-7F combustion turbines and either one or two heat recovery steam generators, but one steam turbine; is that correct?

A. That's correct.

Q. Can you tell me what the rating of megawatts is of the GE-7F combustion turbines, each of them?

A. I can give you a ball park figure. I think they're in the neighborhood of 150, 160 megawatts, each.

Q. And the difference then in the capacity of the combined cycle would be made up by the heat recovery steam generator; is that correct?

A. By the steam turbine and the electrical generator at the tail end, yes.

Q. I notice also you stated, I believe in answer to a question, that there you believed that -- when you were asked the question about adding coal gasification to the Martin Units, I believe you stated that you had not considered it because of the forecast in fuel prices; is that correct?

A. The change over time and the forecasted fuel prices, that's correct. With gas prices dropping, if it's not economical to do coal gasification at the price we originally assumed, as gas prices get lower, it obviously wouldn't be any more cost-effective.

Q. Do you know what kind of a differential on a dollar or cents per million Btu basis you were originally projecting between natural gas and coal at the time of the Martin 3 and 4 need determination?

A. That's all contained in the documents that I don't have copies of, but --

Q. That's all right. I'll check the documents when we get copies, unless you can find it quickly.

A. Let's see if I can find it very quickly here. The differential -- okay, gas price, I'll say for 1996 the differential was roughly $3. And then of course there are different escalation rates that point forward, so that would grow over time.

Q. The differential would grow over time?

A. Yes. In nominal terms, that's right, nominal dollars.

Q. Do you know what the current differential is?

A. Depending on the fuel source, the differential is probably around a dollar or less. And there's a timing element there. I mentioned that gas prices have been very volatile lately, so the differential could have been as high as $1.50, $1.50 a million Btu. It's probably less than that right now. Gas prices are dropping a little bit.

Q. You had also stated, I believe, that it looked like combined cycles were experiencing lower cost, but not IGCCs; is that correct?

A. Right. I mean that's based on actual experience in quotes from the vendors. It's possible that IGCC costs will come down somewhat, because obviously a combined cycle is part of that technology. But since there aren't very many IGCCs being built, it's hard it tell whether that's trending through or not.

Q. You had also said something about FPL had found that on its system it was able to increase the capacity of its existing turbines. Were you speaking there of combustion turbines, steam turbines? Could you define the type?

A. The combustion turbines. And FPL really didn't take any action to do that. It's just by the time they're built, delivered, put on site and tested, we're getting more megawatts than we had originally assumed in our first planning studies.

Q. What type of a progression in terms of heat rate and efficiency in general is being experienced in the marketplace with a given class of combustion turbines, for examples GE-7Fs?

A. The GE-7Fs in a combined cycle configuration, and the actual heat rate at Martin, is roughly 7200 Btus per kilowatt hour. That -- if you look at older technologies -- for example we have the Putnam units on our system, which are an older generation of combined cycles -- would probably be between 8500 and 9,000 heat rate. So over time we're seeing the new technologies are improving the overall heat rate of the combined cycle technology.

Q. Your Martin Units came on line in 1994; is that correct?

A. That's correct.

Q. What type of a heat rate do you expect you would have gotten if you had brought the units on line in 1996? What happened in that two-year period, for example, between 1994 and 1996, in terms of the efficiency of a combined cycle using a GE-7F combustion turbine?

A. I would expect very similar results. There shouldn't be that much of a change as long as you're saying staying within the same family, the same generation of technology. There are slight improvements made. So it might be a hair better, but I don't think we would be talking a significant difference.

Q. I believe you also state, in answer to some questions about the use of natural gas on Florida Power and Light's system, you use the phrase "except on the west coast," referring to the various generating units. What did you mean by that?

A. FPL has generating units at its Manatee site in Fort Myers which are on the west coast. And there is no gas pipeline which reaches those sites, so they burn only oil. We don't have gas capability there. We do have a gas pipeline running down the east coast, which feeds all the units on that side of the state. And that's why on the one side you'll see gas usage, the other side you won't.

Q. Do you copies how far the gas pipeline on the west coast goes? For example, are you perhaps aware that the Hardee Power Station is fired by natural gas?

A. Yes.

Q. How far is that from the Port Manatee site?

A. I don't really copies the distance. I would be guessing. It's a fair distance. But even beyond the distance is the fact that we'd have to convert the technology to burn gas if we decided to do that.

Q. Has Florida Power and Light ever had an IGCC as an avoided unit?

A. Yes. In establishing our '97 standard offer, for qualifying facilities, that was the avoided unit. We had -- in our Scherer proceeding, the unit to which we compared all the RFP responses was an IGCC unit. So in that sense it was the avoided unit in that case also.

Q. Why was an IGCC unit the one that you made the comparisons with in the RFP process?

A. At that time, when those planning studies were initiated to establish those units, we had only enough gas contracted, firm transportation, to basically feed the Martin 3 and 4 units, the Lauderdale units, and leave some gas for the remaining units on our system that required gas. This wasn't so much a pricing issue as a supply issue in that once the gas volume is used up by those units, the next unit in line -- when you make the comparison between the combined cycle, for example, and the IGCC, there is no gas to really run the combined cycle on. So the next unit becomes a coal unit. Then the question is, is it an IGCC or pulverized coal? And our economics at that time, looking at 800 megawatt class units, we felt like that was pretty much break even, with the IGCC having an advantage in the environmental areas that would tend to favor that as the next unit. And that's how that got in after the combined cycle.

Subsequent to that we did acquire more gas. So in later studies, you would see the Martin's 5 and 6, is what they've been designated, running on natural gas in our plants, because there's now a volume of gas to feed those units.

Q. What changed, in Florida Power and Light's estimation, between the time they were considering the avoided unit in an IGCC configuration and your current plans to build natural gas-fired combined cycles? What happened in the gas supply market?

A. We looked at the Phase 3 pipeline expansion for FGT. And in looking at that, we tried to decide, do we want to take a part of that expansion and acquire firm transportation when the pipeline is expanded? We look at that on a system basis. In other words, we don't look at it to feed specific units necessarily, but we look at it as what would happen if we took that volume and then did not build any additional units to take the gas? Is it economic under those circumstances? If it is economic, then we would go and look at what happens now if I do build units to burn the gas? Is that economic compared to the plan that I had before?

If there are savings provided under those scenarios, then we go ahead and contract for the gas, which in this case we did, is acquired another 200 million cubic feet a day for the gas, which I copies you may not be familiar with the volumes, but it's certainly more than enough to run two additional combined cycles. So that just bears out that the logic for acquiring the gas is not just to feed new units; it's basically to feed the system and burn it on the system, because, at least in the near term, projections are that gas will be cheaper than oil. That being the case, if you have units that can burn gas and oil, you'd rather burn gas, certainly in the near term. And that provides the economics.

Q. At the time Florida Power and Light decided to construct Martin Units 3 and 4 as combined cycle, did I understand you to state in answer to Mr. Elias's questions, that one of the generation alternatives that was considered and was rejected was Martin Units 3 and 4 in an IGCC configuration?

A. It was evaluated. To say rejected, it simply wasn't the most economic choice. We did evaluate it versus running Martin's 3 and 4 on natural gas.

Q. Can you tell me what the magnitude of the difference was on a cumulative present worth revenue requirements basis?

A. If I can have Exhibit 1 back. I think it's Exhibit 1. I can take a quick look. (Pause)

Roughly, reading from the graph, I would say it's very roughly $100 million, in 1989 dollars, net present value.

Q. Were you aware at that time of the Department of Energy's clean coal technology program?

A. Yes. In fact in Phase 2 of that program we had submitted a project proposal that was basically to construct an IGCC at Martin, which the DOE did not choose to fund at that time. It was Phase II of the DOE solicitations.

Q. What were the specifics of that proposal, and can you tell me why DOE chose not to fund it?

A. I can only guess at why DOE chose not to fund it, but my guess would be that we asked for too much money. The specifics of the project were to build an 800 megawatt class IGCC at the Martin site based on the Shell technology. Basically the project would be the first large scale demonstration of IGCC and one of the first large scale demonstrations of the Shell technology, and that's why we had proposed it. I think we asked for in the neighborhood of $400 million, something to that effect, which would have used up what I understand to be a large fraction of what they had available. So they chose not to fund it.

Q. I believe you mentioned that was an 800 megawatt project; is that correct?

A. Yes.

Q. Was that a single IGCC or multiple units?

A. IGCC is a little tricky to talk about, because 800 megawatts of IGCC is still two combined cycles, at the end of it. The only thing that really changes in size is the gasifier component, the fuel feed. And that would have been designed to feed 800 megawatts worth of coal gas into two combined cycle units that are very much like Martin 3 and 4.

Q. If in 1989 dollars you had found a cumulative present worth revenue requirements differential between an IGCC configuration and a combined cycle of $100 million, would $120 million of DOE funding have turned the decision in favor of the IGCC?

A. Well, of course that's the purest of speculation. I would have to say, given the attitude at the time, probably not, in that IGCC was considered at that time to be a riskier technology. I think we probably would have wanted a clearer savings than just the 20 million. That's basically break even in the overall scheme of things, when you're dealing with the level of revenue requirements we're looking at here. And when you have a break-even situation, you look at the other factors, the so-called strategic factors, and make your decision on those. We probably would have gone for a more proven technology. But then that's -- like I say, that's just speculation.

Q. If you found yourself in that situation where you had a close equivalency in dollars, comparing two generation alternatives, how would Florida Power and Light, or how does Florida Power and Light evaluate the risk associated with the various technologies? I would first like to copies kind of from an overall perspective, and then secondly, I would like to copies, would you assign dollars to that risk to be incorporated into a cumulative present worth revenue requirements analysis?

A. There are a number of factors that enter into the decision. When you have two alternatives that are relatively close in economics -- and I guess maybe the easiest comparison to do is between a pulverized coal unit and an IGCC for the moment. They both burn the same kind of fuel. Let's assume that their life cycle economics are basically the same, which was what we found in the past to be the case when we evaluated these. On the one hand you have a -- definitely a proven technology. That has the advantage, of course, if you have a fairly certain feel of what the costs will be, but it has the down side of very little expected breakthrough as you build the unit. There's a lot of them have been built. They're basically standard units. You would not expect to see improvements to the costs, nor would you expect to see much in the way of overruns.

IGCC, in FPL's case, looking at an 800 megawatt class, nothing had been built that size. So obviously the cost estimates are less certain. By the same token, you might have an opportunity, as the technology progresses, to improve on the cost estimate. It's largely unknown. So you have to weigh that risk. The other things we would look at, of course, would be the environmental characteristics. IGCC has an advantage there. The use as a -- this gets into our overall plan, but you look at the fuel flexibility of the units. For example, adding a gasifier at the Martin site for Martin Units 5 and 6 would reduce the costs associated with converting Martin Units 3 and 4 to coal gas, should we ever make that decision, because the infrastructure would already be there. So it had that advantage.

So you weigh the pluses and minuses and make a decision on qualitative factors. Do we put dollars to those? No, not in general. The only time dollars get assigned would be, for example, in the environmental area when a price, for instance in SO2 allowances, is assigned. We would put that -- credit that to individual options, certainly, as that becomes known. But there are other environmental characteristics where dollars are not known, and we would not go in and assign dollars to those.

Q. If in a cumulative present worth revenue requirements analysis you found one technology coming out ahead of another, but the benefits were more in the out years, how would you factor that into a decision on what kind of technology to build?

A. Generally, as a rule of thumb, we look at the economics and hope to achieve net benefits on a present value basis within the first ten years. When you're looking at a 30 to 40-year option, for example, the fact that the unit provides benefits in the last two years of a 40-year study, we would not choose that option. Ten years, in general, has been used as a rough guideline for these 30-year units.

Q. Would it depend at all on what type of benefits you were expecting to get in the out years? For example, if the benefit was expected to come in terms of a widening fuel price differential between natural gas and coal, would you still go with your first ten-year standard -- first ten years' standard?

A. In that case, as part of the planning process, we would look at the different fuel forecasts, not just a base forecast, but we typically also use a low band and high band, and how those are developed, you know, is another whole story. But you would look at the economics under those circumstances.

The one advantage -- this is one of those strategic advantages that IGCC has in the way we looked at our plan. If we saw that the economics of the unit were unfavorable during the early years, but appeared to turn around in the late years, the one thing you can do with an IGCC that you can't do with a pulverized coal unit is begin operation on natural gas and convert it later to coal gas. So you can actually get the best of both worlds. You can take advantage of the natural gas economics in the short term, and then if the fuel spread widens, you can convert to coal gasification at a later date and make up for this widening spread.

Now there is additional cost to do that. It's not quite as straightforward as I may have described, but it can be done. You can run these gas turbines, these combined cycles, on coal gasification. In fact we discussed that when we licensed Martin 3 and 4.

Q. How could you protect yourself -- how could a utility protect itself against changed fuel price forecasts if it started out on the IGCC route? I guess my first question would be in relation to the construction period.

A. Well, I guess during the construction period you would simply reevaluate progressing with the unit, as planned, versus switching to another alternative. And the answer to that analysis might dictate what you would do. But again, with IGCC, since it does contain combustion turbine, combined cycle components, the possibility exists that you can sort of abort the gasification phase, if economics say that's the right thing to do. But you can kind of switch gears in the middle. Now there is a point beyond which you can't do that anymore; you will have committed to a certain number of dollars and a certain level of construction. You wouldn't be able to switch back economically.

Q. Is there any simple way to describe the point at which you'd find the point of no return? Is there a dollar comparison that would indicate that you're at that decision point?

A. I can't give you an absolute dollar number, but what it would be is a comparison of the incremental cost to complete the unit as planned versus the incremental cost to complete an alternative unit, in this case probably a combined cycle. At the point where the incremental cost to complete the IGCC is greater than the incremental cost to complete a combined cycle and run that, you would stop and switch, if that were to ever occur.

Q. When you say the point at which the incremental cost of the IGCC is greater, would that be incremental cost on a system cumulative present worth revenue requirements basis or on some other basis?

A. That would be net life cycle cost that includes both the capital cost to complete, plus the operating costs beyond the in-service date, which would include fuel and any other non-fuel O&M. So you would look at the analysis and say, it cost me $10 to finish the IGCC, and it will operate at a certain fuel cost, certain O&M from that point forward. It may cost me $20 to finish this thing as a combined cycle and convert it back to natural gas. Therefore I continue with the IGCC. If the numbers were reversed and the fuel costs gave you the appropriate economics over the long term, you might switch gears.

Q. How would you treat sunk costs in such an analysis?

A. Sunk costs. I guess in the traditional financial approach, you ignore sunk costs. In other words, whatever's been spent has been spent. It's not relevant to the future decision. In comparing combined cycle to an IGCC, that's a little bit of a difficult comparison because you have some costs that are sunk that might apply to both units. And that would depend on the design. But you have, for instance if you buy a gas turbine for the IGCC, okay, now it's bought. The fact that it's been paid for doesn't matter to your future decision. But that same combustion turbine might be bought and applicable to the combined cycle technology. So you have to take it out of there too and then look at the incremental cost from that point forward to finish each of the technologies and the operating costs, once they're in service, to make your decision.

Q. How would you treat the type of combined cycle you would be able to bring on line should you decide to halt construction of an IGCC? Would it be a -- would you factor in the cost of modifying the combined cycle back to run on, for example, natural gas, if that was the least cost alternative?

A. Yes. In the case of an IGCC, I mentioned, it depends on the design. There are various -- the different vendors of coal gasification have different designs, different levels of integration with the combined cycle, and so on. Your ability to convert back to natural gas would be somewhat dependent on what design you were using. And there may be a cost associated with switching back to natural gas. It maybe be that the unit was designed to be very heavily integrated with the gasifier. If the gasifier is not there, you have to change designs. That can be costly in the middle of the process. It all depends on where you are in the overall construction process.

Q. If modification was required, would you assign the costs to the project that required the modification. For example, if there were costs associated with bringing the combined cycle on line in a natural gas configuration, would you assign those costs to the incremental cost of finishing the project as a combined cycle?

A. Yes. If I understand your question, that's what you would do.

Q. If we might, assume that construction has begun on an IGCC and assume further that some costs have been incurred that are associated with combine cycled and some costs have been incurred that are associated with the gasification portion of the assets. Can you outline roughly what the analysis would be on an incremental basis between completing the project as an IGCC and completing the project as a natural gas-fired combined cycle?

A. The -- and again, this is the way I would do it. Have to be clear on that. The costs spent on the gasifier are basically irrelevant, and the only thing you would look at is the incremental cost, on the IGCC side of the study, to finish the gasifier. The costs spent on the combined cycle also need to be thrown out of the analysis, but now the question is how much of that needs to also be thrown out of just finishing as a combined cycle. For instance, if you paid $30 million for gas turbine and it's the same gas turbine you would use to just finish it as a combined cycle, that 30 million should be set aside on both sides of the analysis.

Q. Excuse me. What do you mean by set aside?

A. Disregarded. It should not be included in the numbers. You can, at that point then, look at the cost to finish the IGCC in its planned configuration, whatever that cost is, and the cost to finish the combined cycle in a natural gas-fired combine cycled mode. That may include modification to the unit to burn natural gas. But it's incremental cost versus incremental cost. And then from the in-service date forward, you would look at the operating fuel characteristics of both units and determine the life cycle cost for each, and on a net present value basis determine which is less expensive.

Q. How would you factor in changes in the megawatt rating of the unit going from the IGCC to the combined cycle configuration? First, would you expect a change in the megawatt rating; and secondly, if the combined cycle would necessarily have a lower megawatt rating, how would you consider it?

A. That would, again, kind of depend on the design you're using as to whether the rating went up or down. But, yes, I would expect a difference in rating between an IGCC and the combined cycle for any number of reasons. One is that there is steam fed from the gasifier forward to the combined cycle that can provide megawatts. But there's a tremendous parasitic load from the gasifier, for instance the compression, the gas compression up front. The net of all that may reduce the rating of the IGCC or actually increase the rating of the IGCC.

How do you account for the differences? I don't think there's any standard way to do it. It's a very difficult problem. You can either look at the analysis on a dollars per kilowatt basis and kind of normalize everything, to just look at what it would be if the ratings were the same. You can look to see if your expansion plan changes based on that rating change, and then take that expansion plan change into account when you compare the economics. For instance, if a unit moves forward or a unit moves back, you can take the economics of that and add that to the appropriate alternative. Either one of those has been used and probably will continue to be used. It sort of depends on how many megawatts we're talking.

Another option is to just simply ignore it if it's only a few megawatts and say the difference isn't that substantial. So it would depend on the situation. Generally the way we would do it is to modify the expansion plan to see if units move within the next five to ten years after that change is made to see if there's any economics that need to be taken into account.

Q. If your general planning horizon is, for example, 20 years, would there be any reason you would look at just the first five to ten years to see if units moved, as opposed to reconfiguring your expansion plan for an entire 20-year period?

A. I guess there are a number of reasons why you might look at the first few years. A lot of it has to do with the burden of developing new expansion plans and comparing those alternatives. In our case, with the software we use, it really wouldn't be that much of a problem to see how the units change after you have changed the rating on a given unit, but if you had -- were faced with the burden of using software, you had methods that would take a lot of work to see those changes, you might limit the analysis to just the first few years. And the justification for that, of course, is that in present value terms, once you get out beyond five years, or even ten years, the differences tend to become very small, in general. You may not need that level of accuracy.

Q. You referred earlier with reference to the IGCC configuration, I think you used the term "parasitic load," is that correct?

A. Yes.

Q. How would Florida Power and Light model a parasitic load? By that I mean, would you just net that against the output of the unit, or would you treat the parasitic load as a load on the system?

A. The -- part of that is almost a contractual answer. But given that the IGCC is built as one unit all owned by the same entity, we would net it and simply represent the net megawatts to the system. If you had a situation which has been described as over-the-fence gas supply, where you're buying the gas through a pipeline to feed your units, but somebody else owns the gasifier, and even a third party may own the gas compression facilities, you might model it differently. But from a generation perspective, a generation planning perspective, it really doesn't make any difference, and the netting is appropriate.

Q. Can you tell me what the cost is on a cents per kilowatt hour basis out of Martin Units 3 and 4? And I'm not asking for a precise number, just an approximation.

A. Very, very approximately, the O&M, including fuel, for '95, was about 1.6 cents, between 1.6 and 1.7 cents. The revenue requirements for that -- I'm thinking back to when we did those analyses for comparison in some of the other dockets -- I think it's around 3 cents, 3 to 3.5. So a total of 4.5 to 5 cents, somewhere in there.

Q. Where do Martin Units 3 and 4 dispatch on Florida Power and Light's system?

A. They would dispatch after nuclear, after the coal capacity would have, most of the time that -- with fluctuating gas prices that may vary a little bit, but basically they would come in after nuclear and coal, which means they would be very early in the dispatch for FPL, because we have not a lot of coal on our system. So we're talking about a unit that would look like base load, roughly 80 percent capacity factor or higher in today's market.

Q. Can you compare utilities on a fuel basis to determine where a similar unit would dispatch in their system? And let me try to explain what I'm trying to get at. Assume another utility with fuel costs, let's just say identical to Florida Power and Light, in other words they've got the same load of nuclear, their coal costs are the same as Florida Power and Light's, their nuclear costs are also the same. Is there any reason their unit would dispatch differently on another system? Can you just compare the fuel costs in determining where a unit will dispatch?

A. Just as far as the order in which things dispatch, yeah, you probably can just compare fuel costs. You can take a look at the units on the system, look at the fuel cost to that unit, and estimate where in the stack the combined cycle what fall. That you can do. Capacity factor is a little harder, because now it's a function of load on the system, what kind of load they have. But just looking at what dispatches before what, I think you can do that.

Q. For example, if we had another utility, otherwise similar to Florida Power and Light's, but let's assume its coal units had a lower fuel cost than Florida Power and Light's, could you assume that the combined cycle, identical to Martin Units 3 and 4, would dispatch then in the same order as they would dispatch on Florida Power and Light's system?

A. In other words after the coal units?

Q. Well it would necessarily have to be after the coal units, if that other utility's coal costs were lower.

A. Yes. So it would still be after the coal units, and it would be a function of how much coal was on that utility's system.

Q. Did I understand you, in answer to a question from Mr. Elias, state that from a planning perspective it doesn't make any difference whether a particular unit would be base load, intermediate or peaking?

A. What I was trying to clarify is that there are sort of textbook definitions to different kinds of units. There's a coal unit, which people associate with base load. There is an intermediate range, which people generally classify combined cycles in that range. There are peaking type units, gas turbines. And maybe this is a function of my having consulted with utilities around the country and around the world before I got to Florida, but if you go to Saudi Arabia where they're running all gas turbines on their system and you put a new gas turbine on that system, it could be a base load unit. It could very well. That's all they have. And if they got a slightly more efficient one than the ones that were there, it could run in a base load mode. So it's not -- I guess the point I'm trying to make is that you cannot assume that because units have sort of been pegged into certain holes that that is the way it will run on the system. How it would run on the system is a function of what is already there, as far as fuel mix and technologies. So combined cycle could run base load, as it does on our system. It can run in an intermediate range, as it might on a unit that has more coal. It can run even in a peaking mode, if you had a lot of coal and nuclear on a system.

Q. If Florida Power and Light were considering generation alternatives, and specifically, if Florida Power and Light was considering converting Martin Units 3 and 4 to coal gasification, would the fact that such a conversion would cause the units to run more on Florida Power and Light's system in any way affect the analysis?

A. The way it affects the analysis is if we were to convert Martin 3 and 4 to coal gas, the capacity factor might be very similar in that we're running base load now. What would happen though is, number one, the gas that is released from Martin Units 3 and 4 would displace oil in other units of the system, since they're dual-fired, assuming that gas is cheaper than oil. That would provide an economic benefit.

The other thing that would happen is the coal now, the incremental coal fuel that we've added to our system, would displace even more oil on the system, and back out oil primarily, although it would depend on the given period. So that is all taken into account in the economics. There is -- obviously we're burning more coal than we were, but now they've displaced other fuels. There should be a net savings involved in that, or it wouldn't make sense to do it.

Q. Does Florida Power and Light currently have any plans to construct or convert any of its units to an IGCC configuration?

A. No.

Q. Are any of the costs associated with an IGCC, such as the oxygen plant, properly categorized as O&M as opposed to part of the Btu charge of the output of the unit?

A. It seems like an accounting question. And not being an accountant, I'm not sure how you might categorize the expense. I assume you're talking about the operating expense of the oxygen plant, now, not the capital necessarily.

Q. Yes, sir, in the sense that -- as I understand it, and tell me if you agree in the first instance, that basically what you have with an IGCC unit is a chemical refinery to create the gas, and then you have combined cycle unit. Would that configuration give rise to a different method of accounting for the costs of the -- I guess you would call it the necessary components, but not directly related to gasification. These would be such things as the air separation unit, I think, which is also called the oxygen plant, the sulfuric acid plant and such things as that.

A. Well, I think it would in the sense that this is a very different type of operation than we hava in other plants. It may not necessarily result in a different accounting, but certainly the oxygen plant is -- can be viewed as a variable cost in that you're producing oxygen to run through the gasifier to make the gas that burns in the combined cycles. When the gasifier is not running, the oxygen plant is not running. So the production of oxygen would be a cost associated with the making of the gas that goes into the combined cycle.

Q. In performing an incremental analysis on Florida

Power and Light's system, given the choice between a IGCC and a combined cycle, in your estimation, would you, or the responsible people at Florida Power and Light, ever consider an IGCC against the power block of the IGCC?

A. I'm not sure I followed you. I'm sorry.

Q. Well, for example, if you start out constructing an IGCC, as I understand it, the combined cycle would be constructed. The combustion turbine, specifically, will be constructed to operate on synthesis gas as opposed to natural gas. It will have, perhaps, nitrogen injection. The heat recovery steam generator may have a steam feed from the radiant and convection Syngas coolers. So the combined cycle, the power block itself for an IGCC may differ in several respects from a standalone combined cycle. And my question is: In your estimation, would Florida Power and Light ever compare an IGCC versus a power block, which is just a combined cycle, but configured to run as part of an integrated gasification unit?

A. Only if the costs associated with either modifying or running that unit on a different fuel were accounted for. When we were looking at IGCC, it was my understanding that gas turbines, for example could be designed to run on any two fuels, which you picked during the design phase. Those two fuels, for example could be natural gas and Syngas. You could get two, but you couldn't get three. So if the Syngas went away, it might still be feasible to run the unit on natural gas. There are still questions as far as the steam feeds, as to how much you have integrated the outputs, steam outputs, from the gasifier end to the combined cycle configuration, but assuming you have taken into account the costs of modifying the unit to run without that feed, then the comparison could be made.

Q. And do you copies how that comparison would be done?

A. At any given point in time, going back to the incremental cost approach, you would have to get an estimate from the designers as to what would have to be spent to modify the combined cycle to run in that mode. Once you have that, that would be included in the incremental cost to finish the unit as a combined cycle running on natural gas versus the -- I'll call it the original project cost, assuming you started out as an IGCC. You simply go to the incremental cost of that as it was originally laid out and see how much it would cost to finish the unit in that configuration. And then again, once both units are in service, compare the life cycle cost, the fuel and non-fuel O&M of the two units, to see how the overall economics compare.

Q. Are you familiar with the term EPRI, E-P-R-I, TAG, T-A-G?

A. Yes.

Q. Could you explain what that is?

A. The EPRI TAG, the T-A-G stands for Technology Assessment Guide. That is a book produced by the Electric Power Research Institute, of which we are no longer a member, but when we were a member it was updated annually, and it provides cost and performance estimates of a wide variety of generating technologies that can be used for planning purposes.

Q. Would it be reasonable in your estimation -- in comparing the incremental costs of completion of an IGCC versus completing an IGCC project as a natural gas combined cycle unit, would it be reasonable to use EPRI TAG figures for the combined cycle but not for the IGCC?

A. I think you would be mixing apples and oranges. I don't think that's something you would want to do unless you absolutely had to. One of the problems in EPRI TAG is it doesn't tend to be detailed enough to allow you to make judgments on what part of the dollars go to which component, as I recall, at least when we were using it. It gives you a rough overall estimate of cash flows. It gives you a rough overall estimate of total dollars spent and so on. But how those dollars break out is a little rough, and I don't think you would want to make a comparison on that basis.

Q. How would Florida Power and Light compare the O&M

costs associated with an IGCC versus a combined cycle?

A. We, in fact, did a project, again when we were members of EPRI, to do a design, a preliminary design on an IGCC unit at Martin. So we had developed fairly site-specific cost numbers which were used in our planning process. We worked with basically the vendors, EPRI providing some of the funding, to develop those numbers. And over the years we continued to work with the vendors, vendors being GE for the turbines, Shell/Texaco and Dow for the gasification and so on, to update the numbers that we had, so we could keep sort of an updated database to make these comparisons.

Q. If you were -- if Florida Power and Light had set off to build an IGCC unit and was evaluating whether to change to a combined cycle configuration, what estimate of costs would they use for the respective incremental analysis, that of the IGCC and that of the combined cycle?

A. Well, the incremental cost of the IGCC to complete would basically be looking at dollars committed in the project, which we would copies if we were already underway. The remaining dollars would obviously be the incremental cost to finish. Combined cycle, we would probably have to go back to the vendor or designer to get the cost for that, because that we wouldn't have as part of the standard project. We would go back to, in the case of an IGCC, say a

Bechtel, or whoever had done the design work, and ask them, if we want to finish this as a combined cycle, what do we have to do and what will it cost. They would give us an estimate and then that would go into the analysis.

Q. With respect to the O&M costs associated with the two alternatives, would you use the vendor estimates instead of EPRI TAG numbers?

A. If they were available, yes. It's actually -- we go to the vendor and ask them -- not so much for O&M estimates, we get into a little more detail -- how many people are employed at the site, what kind of materials are needed to maintain the unit, and so on and so forth, and then put an estimate together from that. Because we use in our estimates, for instance, Florida-specific labor rates, which EPRI isn't using. They would take a Southeastern United States average, for example. That's one where they would be different. We try and get it a little more specific to FPL for planning purposes.

Q. Mr. Waters, I'm going to ask you to take a look at a document. This is an exhibit that was introduced in the deposition of Mr. Charles Black, who is vice president and project manager for Tampa Electric Company. The number, Exhibit 33, that is in the top right-hand corner is the exhibit number that was assigned during Mr. Black's deposition.

And Mr. Waters, this is just an excerpt from that. You can see that this is the first page and a subsequent page. I should tell you that the reason it begins with Page 8 is that it was apparently a report or a document authored by Mr. Black that was included in a larger DOE publication. I would ask you to refer to -- first I would like to get an exhibit number for this deposition. Would that be Exhibit 4?

THE REPORTER: Yes.

(Exhibit No. 4 marked for identification.)

BY MR. HOWE:

Q. And if you would refer, please, Mr. Waters, to the second page, the second paragraph -- well, I would ask you, for your comfort with this, if you would first refer to -- if you would like to review those paragraphs under the heading Business Issues Economic Justification. Could we take a moment and let the witness do that? (Pause)

Mr. Waters, you've had a chance then to review those paragraphs after the economic -- excuse me, Business Issues Economic Justification heading; is that correct?

A. Yes.

Q. If you would look at that second paragraph under that heading, and in particular that second sentence where it reads, and I quote, "I believe that in order for IGCC to compete on a commercial basis, that natural gas prices have to rise relative to coal prices and that the capital costs of the technology must come down." Do you agree with that statement, sir?

A. Yes.

Q. In the fourth paragraph after the heading, where it refers to the efficiencies associated with a combined cycle, and with an IGCC, and I believe -- let me see if the particular provision I was looking at -- Do you agree, Mr. Waters, that the advances and improved efficiencies associated with the combined cycle portion of the IGCC is also associated with a standalone combined cycle?

A. Yes. I think maybe just to make sure I'm clear, the efficiency improvements that result from improved combustion turbine efficiency and therefore combined cycle efficiency, should also be included in IGCC technology.

Q. Mr. Waters, if Florida Power and Light performed an incremental analysis, it had first started out to build an IGCC, and because of a later incremental analysis decided to proceed with a combined cycle, not a gasified combined cycle, how would Florida Power and Light treat the sunk costs for regulatory purposes?

A. Ultimately we would hopefully make a showing that switching to the alternate project was most cost-effective, and you've done that on an incremental cost basis. When it comes to recovery of costs, there would be a similar showing in that the total recovery from customers for the new technology, including sunk costs, would be less than the total recovery that would have occurred had you finished the project as scheduled. So that would be the proposal, that we have still chosen the most economic path, but you would hope to recover sunk costs, I think, as part of that switch. In other words, even though you write them off for analysis purposes, that doesn't mean you simply disregard them when it comes to recovery purposes.

MR. HOWE: I have no further questions. Thanks a lot, Mr. Waters.

(Discussion off the record)

EXAMINATION

BY MR. LONG:

Q. Mr. Waters, good afternoon. I'm Harry Long, and I am representing Tampa Electric this afternoon. I have a few questions to ask, and I'll try to make it as brief as possible so you can catch your plane.

A. That's all right. There are later flights, so that shouldn't be a constraint. Not that I'm volunteering to stay for several hours.

Q. I'll try to make it brief anyway. I would like to go back to a couple of the questions that were asked by Mr. Howe and Mr. Elias, and then I have some additional questions. In your conversation with Mr. Howe, you talked about the proposal that you submitted to DOE for -- I believe it was an 800 megawatt IGCC unit?

A. Correct.

Q. That was based on the Shell technology?

A. Yes.

Q. And you requested a grant of $400 million for that unit?

A. I believe that's roughly the number. I don't remember the precise number, but my recollection is between 4- and $500 million.

Q. Had you received the grant, would you have proceeded with the unit?

A. I can only speculate, but yes, we probably would have. The size of the grant we were asking for was to cover -- actually more than cover, the capital differences we saw between that and the other technologies over the present value differences, and also offset some of the operating costs, at least in the early years.

Q. And what were the capital differences, again, that you estimated?

A. Capital is probably not the right word. The net present value difference I mentioned before in our need filing was about $100 million net present value, and that was in '89 dollars, between that and the combined cycle.

Q. And that was for the 800 megawatt unit?

A. Yes.

Q. Now you've mentioned that on several occasions you've done cost-effectiveness studies of IGCC units as compared to alternatives that might be available to you.

A. Yes.

Q. In those studies, did you assume the existence of a grant or subsidy of any kind?

A. No.

Q. And what feed stock were you assuming in those studies?

A. Basically a standard bituminous coal. I don't know the coal grades that much, but it would have been coal feed stock.

Q. So you didn't assume in any of your studies a pet coke feed stock or some blend of pet coke?

A. No.

Q. Now you were asked some questions about the Martin Units 3 and 4 and the cost estimates. I believe you indicated in response to questions from Mr. Elias that the projected cost at the time of the need hearing was $676 million?

A. That's correct.

Q. Did that include the transmission upgrades?

A. Yes.

Q. Is it correct then that the total cost, including transmission on a kilowatt basis, was $878 per kilowatt?

A. Yes.

Q. Now you mentioned that the installed cost was somewhat less. I think you mentioned 511 million?

A. That's correct.

Q. Now you indicated that a good part of that cost reduction was due to what you described as project management. You also mentioned that part of that related to favorable costs on the hardware. Can you explain to me what you meant by that and --

A. It's an assumption on my part that in the acquisition of the hardware they were able to get a better price than had originally been estimated. Being a new technology, the 7F, there wasn't a lot of history with it, not a lot of purchasing done on that unit. A price was put in for the initial estimate. I would assume there was some savings when those were actually acquired.

Q. Do you copies how much the savings might have been?

A. No.

Q. Would it have been attributable to purchasing two units?

A. I don't think so, in that the plan from the beginning was to construct the two units. So any possible savings due to, say an economy of scale type of thing, would have been accounted for initially. If there is a savings there, it is probably more attributable to the fact that both Westinghouse and GE were very competitive in trying to provide turbines for that site.

Q. If you'll bear with me for a minute, I would like to ask you a couple of questions about Exhibit 3, your fuel forecast. (Pause)

I'm going to ask you to make some comparisons for us looking at your '95 and '96 forecasts. And what I would like you to compare, for the years that I'll mention in a moment, is the system weighted average gas price in dollars per MMBtu with your forecasted high sulfur coal price, the weighted average nominal, in dollars per MMBtu and your forecasted petroleum coke price in dollars per MMBtu. For each of those fuels, would you take a look at the years 1998, 2003, 2019 and 2024, and for each of those two studies, would you tell us what the differential is between the forecasted gas price and the forecasted high sulfur coal price, on the one hand, and then the differential between gas and the petroleum coke price on the other?

A. Okay.

Q. Oh, I'm sorry, you probably need this.

A. This is for the '95 and '96 forecast?

Q. Yes, please. (Pause)

A. Okay, I've got some numbers anyway.

Q. Start with the '95 forecast. For the four years that I mentioned, can you first tell us what the differential is between the gas price and the high sulfur coal price?

A. I think I screwed up here. I used '95 and '96. '95, let me double check here. Yeah, I skipped over and I used '94 and '96. Hang on. (Pause) Okay. I used '95 and '96. I'll come back to '94.

Q. Really, we just need '95 and '96 for now.

A. Okay. The '95 forecast -- and the question was?

Q. The differential, first, between high sulfur coal and the weighted average gas price.

A. 85 cents per million Btu.

Q. And is that in '98?

A. Yes.

Q. And what is it for 2003?

A. $1.46.

Q. 2019?

A. $4.39.

Q. 2024?

A. $5.59.

Q. Now, I take it the relationship between the coal price and the gas price is not constant over that forecast period?

A. That's correct.

Q. The prices are divergent?
A. Yes.
Q. Now, for '95, can you again tell us what the differential is between the pet coke price and the gas price?
A. $1.73.
Q. For '98?
A. Uh-huh.
Q. And then for 2003?
A. $2.56.
Q. 2019?
A. $6.28.
Q. And for 2024?
A. $7.78.
Q. Again, the relationship isn't constant?
A. That's correct.
Q. And the prices are divergent?
A. Yes.
Q. Let's look at the '96 forecast. Again, can we start with the forecasted differential between the high sulfur coal price and the natural gas price?
A. Okay, 60 cents per million Btu in '98, $1.01 in 2003, $3.10 in 2019 and $3.69 in 2024.
Q. And the difference between gas and pet coke?
A. In '98, it's $1.46 per million Btu. In 2003,

$1.98; in 2019, $4.49; in 2024, $5.25.

Q. So, again, in both cases for '96, the relationship between gas and coal on the one hand and pet coke on the other is not constant?

A. That's correct.

Q. The differential increases in both cases?

A. Yes.

Q. Mr. Waters, would it be prudent for FPL to adopt and implement, without modification, Tampa Electric Company's generation expansion plan?

A. No.

Q. Why not?

A. The systems are different. The first difference is size of the system and so on. It would -- we would need more capacity in our system than Tampa Electric would. The systems that exist today are different, so the technology choice might be different. Tampa primarily coal, FPL primarily oil/gas, or more of a diverse mix. So I would expect different answers.

Q. Would you agree that a unit that's cost-effective on one utility system may not be the most cost-effective option on another utility system?

A. Yes, it would be dependent on the characteristics of the system.

Q. Now, can you tell me when the Martin site was first purchased by FPL?

A. I really don't copies. The site has been -- has had units on it since the early eighties, so it was well before that, I assume.

Q. Do you copies when the Martin site was put into rate base?

A. I can only assume, on that, that it would have been an issue in FPL's '83 rate case, but I really don't copies. I haven't looked at that.

Q. But as far as you copies, the entire site is in rate base?

A. Well, when we look at the site today, as long as we're clear on what's in base rates and what's in rate base, for earnings purposes I believe the entire site is in our rate base. The rates were not set with everything that's there today, being on site, obviously, because we have new units there.

Q. Are the Martin Units 3 and 4 reflected in your surveillance report to the Commission?

A. Yes, I believe they are.

Q. And when did you start reflecting them in your surveillance report?

A. Reflecting them in the sense from commercial operation forward, which would have been 1994, they would be reflected as operating units. Prior to that time, obviously, there would have been accrued AFUDC and so on reflected.

Q. So they have been reflected since the day of commercial operation?

A. In the sense that they are -- basically there is an asset there that's operating. I mentioned the earlier period just because there is an impact during construction because of AFUDC.

Q. What is the significance of including these units in your surveillance report?

A. Well, I'm not sure I understand the question. The significance is it's an asset of the Company used for producing electricity and should be reported in the surveillance report.

Q. Does the inclusion of these units suggest that these units are currently in the rate base?

A. I want to be clear that while we're calculating, we may calculate earnings based on those being in rate base. That does not necessarily mean that the Commission has passed judgment on the final cost of the units at this point. If and when FPL comes in to reset its rates, that may be an issue in a rate setting case, but the costs to date have been reviewed, have been audited and we have included them as far as an asset of the Company.

Q. So for purposes of calculating earnings, you included Units 3 and 4 in rate base from the date of commercial operation?

A. I believe that's correct.

Q. To date, has there been a prudence review by the Commission of your investment in Units 3 and 4?

A. The units have been audited, but I don't believe there's been a formal prudence review in the sense of a hearing at the Commission, but the Commission Staff has audited the expenditures of the unit.

Q. Just to understand the answer you gave before about changing rates, is it your view that no further Commission action with regard to the prudence of these plants is warranted until such time as you attempt to adjust rates to reflect these units?

A. No, I don't think that's what I'm saying. I think at that time it would be an issue. Obviously the Commission is interested in the expenditures of that unit. That's why we've been audited as far as total expenditure on the units. What action the Commission would take, I really don't copies. I don't have a feel for that.

Q. Did you receive any explicit Commission authorization to begin including these units in your surveillance report?

A. I don't know. I -- really, these are accounting questions, and I'm not that familiar with how that was done.

Q. But you are not aware of any Commission authorization to include these units in your surveillance report?

A. I am not aware of any. That doesn't mean it doesn't exist. Obviously when they were included. that would be noted. And what action the Commission took with that information, I don't know.

Q. Now you stated earlier that you are responsible for all of FPL's regulatory filings?

A. Today, yes.

Q. Do you have any idea how the Martin site was initially selected as a location for power plants?

A. Originally? You mean before the first two units were even --

Q. At the time the first two units were constructed.

A. No, I'm not familiar with that process.

Q. Can you tell us how you decided to put Units 3 and 4 on the Martin site?

A. Yes. That was done through a siting study which reviewed not only FPL's existing sites but potential sites in Southern Florida for generation Southern Florida was focused on, because of the nature of the transmission system and the reliability associated with locating generation close to the load. Based on the -- a number of factors, including the availability of fuel, fuel transportation, transmission capability and so on, Martin was chosen as the preferred site for new generation. And this even predates Units 3 and 4.

Q. At the time that you were siting Units 3 and 4, did FPL own any other potential power plant sites?

A. Yes.

Q. Can you tell me what those sites were?

A. Two sites specifically, one in DeSoto County and one in South Dade County.

Q. And can you tell me approximately how many acres in each of those sites?

A. Maybe. (Pause).

Q. For North Dade, subject to check, would you accept that that site is about 3,000 acres, 3,097 acres?

A. The South Dade site?

Q. Yeah -- North Dade.

A. We refer to it as the South Dade site. Is there something --

Q. Oh for South Dade then. I'm sorry, that was my mistake. Would you accept, subject to check, that South Dade is approximately 13,400 acres?

A. I'll accept that subject to check.

Q. And the other site that you mentioned was DeSoto; is that correct?

A. Yes.

Q. And would you accept subject to check that that's approximately 13,500 acres?

A. I'll accept that subject to check.

Q. Do you copies if those two sites were in rate base at the time that you were siting Units 3 and 4?

A. I don't know.

Q. Do you copies if those two sites are now in rate base?

A. I'm really not aware of their status right now.

Q. Who would copies that?

A. Our accounting -- someone in our accounting department I'm sure would copies.

Q. Would it be possible for you to submit a late-filed exhibit to your deposition providing that information?

A. As to whether or not those two sites are in rate base?

Q. Yes, and if they are, how long they've been in rate base.

MR. HOWE: Excuse me. For clarification on that, are you asking him rate base for surveillance purposes or rate base for purposes of rate setting?

MR. LONG: Well, both.

MR. HOWE: Or to distinguish between the two?

MR. LONG: I would like information on both.

MR. HOWE: All right.

MR. LONG: Thank you.

BY MR. LONG:

Q. Mr. Waters, are those the only two power plant sites that are in rate base at the current time?

A. Well, I'm not sure they are in rate base. That's something that would be in the late-filed exhibit. Those are the only two sites I'm aware of that we own that do not have existing generation. We obviously have a number of other sites where generation might be placed, the existing sites on the system where generation already exists. But these are the two that I am aware of that do not have generation and have the capability for added generation.

Q. So in Late-filed Exhibit 5, you'll tell us if those two sites are in rate base, and if they are, when they were included in rate base. And then would you also include on that exhibit a listing of the other sites where you have expansion capability, and indicate generally the acreage for those sites, and again, if they're in rate base when they were added to rate base.

THE REPORTER: Can you give me a short title please?

MR. LONG: FPL Expansion Sites.

(Late-filed Exhibit No. 5 identified.)

BY MR. LONG:

Q. Mr. Waters, you mentioned that Units 1 and 2 at the Martin site are each 800 megawatt units?

A. Yes.

Q. Do you copies what the per kilowatt cost was for the first 800 megawatt unit on that site?

A. No, I don't.

Q. Do you have that information at your office?

A. The per kilowatt cost. The way I could determine it, I suppose, is to look at the in-service cost, which should be accessible, and just divide that by kilowatts.

Q. You're saying you would divide it evenly between the two 800 megawatt units?

A. Well, not necessarily. I would look at the way the in-service cost was accounted for.

Q. Would you mind providing that as well? We'll call that Late-filed Exhibit No. 6.

(Late-filed Exhibit No. 6 identified.)

MR. CHILDS: We may mind, depending upon how many more requests you have.

MR. LONG: Well, if you have an objection, you can state it. Otherwise I would like the information.

MR. CHILDS: I'll object to both of these, then, if you won't tell me how many more you have.

MR. LONG: I don't have any in mind. I'm looking for relevant information to this case. Those two items, in my view, are relevant, and to the extent that there's other information that's relevant, I'll ask for it.

MR. CHILDS: You can do that and I can object.

MR. LONG: Sure you can.

BY MR. LONG:

Q. Mr. Waters, what external oil and gas forecasts do you rely on?

A. Currently we use the DRI forecast as the basis for our own internal fuel forecast. There's also an effort to look at other forecasts. So to say "rely on," I guess I would have to say we use kind of a market scan to look at a number of different forecasts, but DRI is basically the starting point for our forecast.

Q. Period '91 through '95, did you rely on different external forecasts, if you copies?

A. I am not certain of the year it changed. But I think it was 1993. Prior to that time I think we relied more on our own internal forecasts, and that those internal forecasts, again, referred to a number of different commercial forecasts and publicly available forecasts to look at sort of a consensus view of the market, but that the numbers were generated internally. After that time, DRI became the -- I'll call it the base forecast, which was then converted to delivery in Florida, to our various sites, but it served as a basis.

Q. If you copies, how do you determine the reasonableness of your forecasts?

A. That goes back to this review of the alternative forecasts. Looking at different providers of forecasts, different agencies, the U.S. Government puts out forecasts, different economic forecasters do forecasts. Reasonableness has to be -- it is somewhat subjective, but you have to look at it in view of what the majority of forecasters are saying.

Q. Do you assign probabilities to your forecasts?

A. In the planning process, no, we have not done that. Now, whether the forecasters themselves use any kind of probabilities in developing the forecasts, I don't know. Once the forecast is input to the planning process, no, a probability is not assigned.

Q. Can you describe the generation mix on your system by percentages?

A. Energy -- I can give you some approximate numbers. I'll do it very approximately. Nuclear represents about 20 percent on our system; oil between 15 and 20 percent; gas between 20 and 25 percent, and then the remainder is purchases. So it's purchases in coal. Coal represents, from an ownership share, less than 10 percent. The remainder is purchases. So it's fairly evenly divided amongst four fuel types.

Q. I would like to go back to some questions on the Martin site at the time you sited Units 3 and 4. Can you tell me what site preparation costs you incurred when you put in Units 3 and 4?

A. I don't really have a number. They would have been relatively small.

Q. Did you have any environmental mitigation costs peculiar to Units 3 and 4?

A. There were some. I don't know the magnitude. I don't think there was a major expenditure, but there were some.

Q. The existing cooling pond was sufficient to meet the needs of Unit 3 and 4 at the site?

A. That's correct.

Q. And as I understand it, the site was already served by rail?

A. I believe that's correct. If not, it was very near by. There is a rail line very close by. In the planning for the site, if we had added coal capability, there was the potential for running spurs into a coal yard there, so I don't think it would have been a major undertaking.

Q. From a planning point of view, do you think it's important for a utility to have more than one potential site for power plants?

A. I guess if you mean identifying more than one potential site, yes; owning more than one potential site, not necessarily. But certainly you would want to be looking forward enough to be looking at sites beyond your next unit, in most cases. Depends on the growth rate.

Q. If I understood what you were staying before, FPL owns more than one potential site for a power plant; is that correct?

A. That's correct.

Q. Why is that important to FPL?

A. What value it has is difficult to say. That goes back quite a ways before I became involved in planning. And the expansion plan has changed over the years, as technology and the amount of land used and so on. It was felt to be important, and certainly in the high growth days of the seventies, that there would be adequate sites for the future generation. Growth has slowed somewhat. It's still important to have sites available, especially if you look to the long term where sites are going to become more scarce.

Q. Bear with me for a moment. (Pause)

Thank you, Mr. Waters, I don't have anymore questions.

MR. WILLIS: Matt, I take it since you're not faced with a whole multitude of late-filed exhibits, that you will withdraw your objection for those two?

MR. CHILDS: I think the basis for my question at first, in the first instance, is that I thought that if information was otherwise available, that there is a way for you people to track it down rather than asking us to go fetch it, and so I was trying to find out how much you had in mind. And if it wasn't very much, then we would obviously try to accommodate you. I assume we'll do the best we can to respond to these requests.

MR. WILLIS: Okay.

MR. ELIAS: Can we establish a time frame, approximately, when those exhibits will be filed or completed?

MR. CHILDS: Are you under any -- were you under any rapid time schedule?

MR. ELIAS: Yes and no. I mean if Mr. Willis thinks they're relevant to issues outstanding in this case, and Mr. Long, I don't have any objection to filing them after the deposition transcript would be filed.

MR. LONG: Can we have some sense of how soon after the deposition transcript?

MR. CHILDS: I don't even know when the transcript is going to be ready. When is that going to be?

MR. ELIAS: We'll discuss that later. But my point is this, is -- in the event that we file the deposition transcript as direct testimony in this case, I have no objection to those late-filed exhibits being filed at a later date, if they're available afterwards, and being made a part of the record that way.

MR. LONG: I would like to have access to them in time to make use of them for rebuttal, if that's appropriate.

MR. ELIAS: I certainly think that that's reasonable.

MR. CHILDS: What does that mean for us?

MR. ELIAS: Rebuttal testimony is due July 1st.

MR. WILLIS: Can you get those done in a couple weeks, Matt.

MR. CHILDS: I think we can. If we have a real problem in a couple weeks, I'll let you copies. I don't think we're going to have any problem with it though.

MR. ELIAS: Does the witness wish to waive reading and signing of the deposition?

THE WITNESS: I would like to look at it.

MR. ELIAS: One more question, Mr. Waters. Do you expect to be in Tallahassee on the 17th of next month?

THE WITNESS: Not if I can help it.

MR. ELIAS: Normally you would expect to be in Miami working?

THE WITNESS: Yes.

MR. ELIAS: That's all I have.

(Deposition concluded at 2:30 p.m.)

REPORTER'S DEPOSITION CERTIFICATE

STATE OF FLORIDA)

COUNTY OF LEON)

I, LISA GIROD JONES, Registered Professional Reporter, certify that I was authorized to and did stenographically report the above-styled deposition; that a review of the transcript WAS requested; and that the transcript is a true and complete record of my stenographic notes.

I further certify that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 11th day of June, 1996.

Lisa Girod Jones

LISA GIROD JONES, RPR, RMR

CERTIFICATE OF ADMINISTERING OATH

STATE OF FLORIDA)

COUNTY OF LEON)

I, LISA GIROD JONES, Registered Professional Reporter and Notary Public for the State of Florida;

DO HEREBY CERTIFY that the witness named herein personally appeared before me at the time and place designated and was duly sworn.

WITNESS MY HAND AND SEAL this 11th day of June 1996, in the County of Leon, State of Florida.

Lisa Girod Jones

Lisa Girod Jones, RPR, RMR
Notary Public, State of Florida

LISA GIROD JONES
MY COMMISSION EXPIRES
MAY 11, 1997
#CC 280206
NOTARY PUBLIC, STATE OF FLORIDA

EXHIBIT NO. 1

DOCKET NO.: 960409-EI

WITNESS: WATERS

DESCRIPTION: FPL MARTIN 3 AND 4 NEED DETERMINATION STUDY

Exh. 1

SB Waters

EXHIBIT

Petition to Determine Need For Electrical Power Plant 1993 – 1996

(REVISED NOVEMBER 1989)

FPL

FPL

Florida Power & Light Company

PETITION

TO DETERMINE NEED

FOR ELECTRICAL POWER PLANT

1993 - 1996

Revised

November, 1989

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EXH. 1

EXHIBIT

Petition to Determine Need For Electrical Power Plant 1993 – 1996

(REVISED NOVEMBER 1989)

FPL

FPL Service Territory

FPL

Florida Power & Light Company

PETITION
TO DETERMINE NEED
FOR ELECTRICAL POWER PLANT
1993 - 1996

Revised

November, 1989

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EXECUTIVE SUMMARY

Florida Power & Light Company (FPL) has determined a need to add approximately 2,000 MW of new generating capacity on its system between 1993 and 1997. This capacity is needed to maintain adequate system reliability in the face of increasing demand for electrical energy coupled with declining power purchases from the Southern Companies. FPL's studies show that the best series of unit additions to meet its need is as shown in Table 1.

Power Supply Expansion Plan

Total Installed Cost ($/KW)	Year	Addition	Summer Net
		Lauderdale Repowering Project[1]	
818	1993	Repower Lauderdale No. 4	286 MW
		Repower Lauderdale No. 5	286 MW
		Martin Expansion Project[1]	
821	1994	Martin Combined Cycle No. 3	385 MW
821	1995	Martin Combined Cycle No. 4	385 MW
2,229	1996	Integrated Coal Gasification Combined Cycle (IGCC) Plant consisting of:	
		Martin Combined Cycle No. 5	384 MW
		Martin Combined Cycle No. 6	384 MW
		Total	2,110 MW

Notes:

[1] The Martin Combined Cycle units and the repowered Lauderdale Units are all 400 MW class units. Because FPL's planning is based on its need to meet summer peak demand, all analysis is based on the expected summer net ratings of the proposed units. Actual summer net ratings may vary based on final design and performance testing.

Table 1

This series of unit additions reflects the need for new generating capacity that remains after implementation of all reasonably available, cost effective alternatives to new construction. These alternatives, which total over 3,000 MW, include: incremental conservation (126 MW), load management and interruptible load (1,003 MW), firm purchases from qualifying facilities (1,095 MW, of which 515 MW are currently under contract) and power purchases from the Southern Companies (911 MW). It should be noted that the integrated coal gasification combined cycle (IGCC) plant that comes into service in 1996 will meet FPL's projected reliability requirements through 1997.

This need determination document supports two separate petitions filed by FPL - a petition to determine the need for the repowering of Lauderdale Unit Nos. 4 and 5 by 1993 (i.e., the "Lauderdale Repowering Project") and a petition to determine the need for four new units at the Martin site between 1994 and 1996 (i.e., the "Martin Expansion Project"). FPL has filed two need determination petitions, rather than one, because the projects are at different sites and consequently, environmental licensing under the Florida Electrical Power Plant Siting Act must proceed separately. FPL is presenting information regarding the need for both the Lauderdale Repowering Project and the Martin Expansion Project in a single document for several reasons:

- First, a unified presentation is consistent with FPL's internal planning process and provides the Florida Public Service Commission (FPSC) with the best overall picture of FPL's needs. By evaluating competing streams of unit additions over a multi-year planning horizon, both FPL and the FPSC can properly consider both longer lead time units and larger units that incorporate economies of scale.

- Second, a unified presentation results in a more efficient use of FPL's and the FPSC's resources by giving the FPSC the information necessary to complete the certification of as many units as possible in a single proceeding.

- Finally, completing the licensing of all or some of the Martin units in advance of the latest possible date enhances FPL's flexibility to adjust the timing of those units, or to consider phased construction of the combustion turbine portions of those units, if unexpected increases in demand or unexpected decreases in supply side resources threaten FPL's system reliability earlier than currently predicted.

FPL's determination of capacity needs results from its on-going power supply planning process. FPL experienced an average compound annual growth in summer peak demand of approximately 4.0% for the period 1978 through 1988. That demand is projected to continue to grow at a rate of approximately 2.4% per year over the next two decades. At the same time, power purchases from the Southern Companies will decline to an annual average of 911 MW in the mid-1990's, down from their current level of 2,000 MW.

FPL's reliability analysis shows that in order to meet its dual reliability targets of less than .1 day/year assisted loss-of-load probability (LOLP) and minimum generation reserves of 15% based on summer peak demand, FPL would require, in the absence of other measures, additional capacity resources beginning in 1992, totalling over 5,000 MW by the year 1997.

FPL analyzed its generating needs by first assuming that all of the incremental demand would have to be met by FPL constructed new generation. Through a two stage analysis, FPL determined the series of unit additions that would best meet this total incremental need.

- The first stage of analysis identified candidate generating units based on consideration of availability in the required time frame, technological maturity, technical feasibility and the use of economic screening curves which compared the levelized revenue requirements of various options over a range of capacity factors.

- In the second stage, the candidates which passed the initial screening (advanced combustion turbine, advanced combined cycle, advanced combustion turbine repowering, IGCC and pulverized coal units) were evaluated using the more detailed PROSCREEN economic simulation program. This program provided the present value of revenue requirements (PVRR) of different unit combinations over a thirty year horizon. The resulting PVRR information was evaluated, together with non-economic strategic considerations, to select the optimum series of unit additions.

This analysis resulted in a "Reference Plan" in which FPL's total capacity need was met by the addition of over 5,700 MW of generation between 1992 and 1996.

FPL then conducted an economic and strategic analysis of demand side and purchase alternatives to determine how much of this new construction could be avoided by incremental conservation, load management, interruptible load, potential qualifying facilities, and the recently concluded power purchase agreement with the Southern Companies. This analysis showed that these alternatives to new construction would defer the first capacity addition from 1992 to 1993 and would reduce the total amount of new capacity through 1997 from over 5,700 MW to approximately 2,000 MW.

This analysis resulted in the development of the "Base Plan," consisting of the Lauderdale Repowering Project and the Martin Expansion Project (see Table 1). The economics of the Base Plan were then compared to the economics of other combinations of unit additions to verify that it was the optimum plan for meeting the portion of FPL's capacity requirements that remained after the implementation of all alternatives to new construction. The various combinations of unit additions were tested under a number of scenarios and sensitivities designed to determine their flexibility under changing conditions, including changes in fuel price and availability, peak demand forecasts and economy energy availability.

The Base Plan was found to be the optimum power supply expansion plan. The unit additions in this plan provide a flexible, cost effective approach to meeting the future needs of FPL's customers. In combination with the other demand and supply side alternatives discussed above, this plan represents significant savings compared to a plan based on new construction alone.

The balance of this document contains more detailed information and analysis supporting certification of the Lauderdale Repowering Project and the Martin Expansion Project.

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I. INTRODUCTION

A. Purpose And Overview

This document supports petitions to determine the need for new electrical generation on the Florida Power & Light Company (FPL) system, consistent with the informational requirements contained in Section 25-22.081 of the Florida Administrative Code. The information presented herein will "*allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, and the need to determine whether the proposed plant is the most cost effective alternative available.*"

Included in the following sections are:

- A description of the existing FPL system (*Section I.B*).
- A detailed discussion of the methodology used to determine need and compare the cost effectiveness of alternatives (*Section II*).
- A comprehensive discussion of the assumptions underlying the analysis, including projections of peak demand and energy, fuel prices and availability, financial data and a description of the generating and non-generating alternatives evaluated (*Section III*).
- A discussion of the analysis performed and a full presentation of the study results (*Section IV*).
- Unit specific information, including cost data for the capacity additions identified as a result of the planning study (*Section V*).

- A discussion of the consequences of delaying the in-service dates of the proposed units (*Section VI*).

In addition to the above sections, detailed background material has been provided in a series of appendices.

B. Description Of FPL System

FPL is the fourth largest investor owned utility in the nation. As of December 31, 1988, FPL served a total of 2,953,621 customer accounts in thirty-five Florida counties. The Company's service area contains approximately 27,650 square miles with a population of approximately 5.8 million.

The existing system, including service boundaries, generating plants, substations and transmission lines, is shown on the following map entitled "*Substation and Transmission System of Florida Power & Light Company.*"

The existing FPL generating capability is comprised of thirteen generating facilities distributed geographically around its service territory. The current generating facilities consist of four nuclear steam units, twenty-four fossil steam units, forty-eight gas turbines, two diesel installations, two combined cycle units and two coal units (See *Appendix A* for further information on FPL's generating units).

FPL's bulk transmission system is composed of 985 circuit miles of 500 KV lines (including 75 miles of 500 KV lines between Duval Substation and the Florida-Georgia state line, which are jointly owned with JEA) and 2,336 miles of 230 KV lines. The underlying network is composed of 1,431 miles of 138 KV, 638 miles of 115 KV and 248 miles of 69 KV transmission lines. Integration of the generation, transmission and distribution system is achieved through FPL's 397 substations. FPL is also interconnected to neighboring utilities at voltage levels ranging from 69 KV to 500 KV. A list of major interconnections (i.e., 230 KV and 500 KV) is shown in *Appendix A*.

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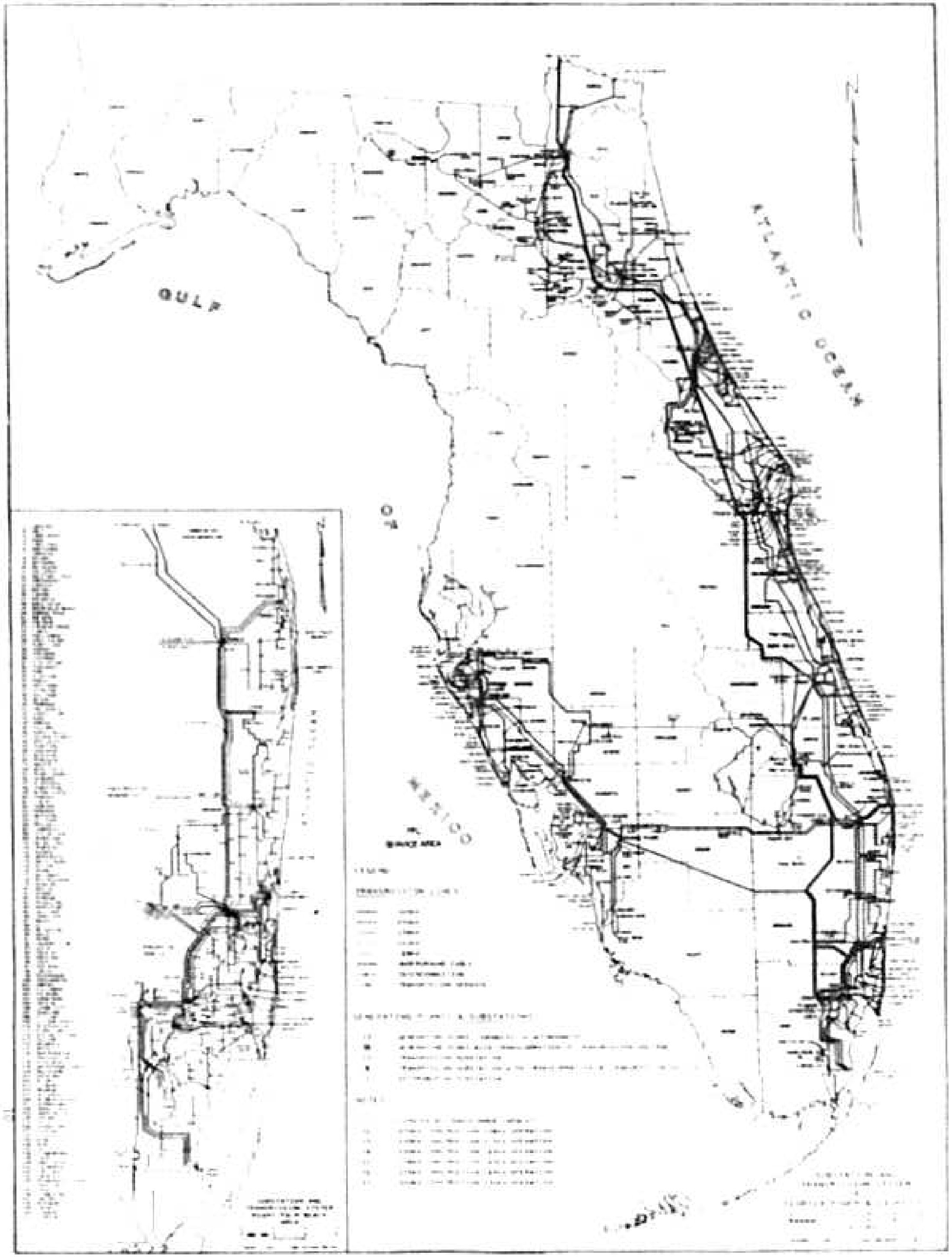


GULF
OF
MEXICO
ATLANTIC OCEAN
SERVICE AREA

II. METHODOLOGY

The objective of FPL's power supply planning process is to meet its customers' electric needs as reliably and economically as possible, with due regard to environmental, financial, regulatory and other considerations. To accomplish this objective, FPL evaluates a wide range of supply side options and demand side alternatives to new construction. The purpose of this section is to provide a description of the methodology used in FPL's power supply analysis.

A. Overview Of The Power Supply Planning Process

FPL's power supply planning process is illustrated in Table II.A.1. The seven major steps of the process are as follows:

Planning Process Steps
1. Gather Data and Prepare Assumptions
2. Reliability Assessment
3. Screening Evaluation
4. Create a Reference Plan
5. Evaluate Alternatives to New Construction
6. Identify the Base Plan
7. Scenario and Sensitivity Analyses

Table II.A.1

The first step is to *Gather Data and Prepare Assumptions*. The data and assumptions include information on FPL's existing system, information on generating options and non-generating alternatives, and load and fuel forecasts. These input data and assumptions are described in more detail in *Section III*.

FPL then performs a *Reliability Assessment* to identify the timing and amount of its capacity needs. FPL uses the dual reliability targets of reserve margin and assisted, or net, Loss-Of-Load Probability (LOLP) in its planning process. Other means of reducing capacity needs, such as increasing the availability of existing units, are also considered in this assessment. See *Section II.B* for more detail.

The *Screening Evaluation* is the step that identifies the generating options that are candidates for meeting the capacity need. There are two screening steps. First, a broad range of potential generating options are examined for availability in the required time frame, technological maturity and technical feasibility in FPL's service territory. The options that are not capable of meeting FPL's needs are eliminated. Second, the overall economics of the remaining options are evaluated using screening curves. The screening curves identify the candidate units to be carried forward into the detailed economic and strategic analysis. See *Section II.C* for more detail.

The next step of the planning process is to *Create a Reference Plan* which represents the optimal "supply side" plan, assuming that all future capacity needs must be met by the construction of new power plants. This Reference Plan is used later as the basis for evaluating the relative economics of alternatives to new construction. Creation of the Reference Plan involves identification of alternative series of generating unit additions that would satisfy FPL's capacity need, followed by detailed economic and strategic evaluation of these plans. This step is described in more detail in *Section II.D*.

FPL then *Evaluates Alternatives to New Construction*. The overall economics of a specific alternative, such as load management or power purchases, are compared to the economics of the unit or units in the Reference Plan that the alternative would displace. If an alternative is found to be cost effective and to meet FPL's strategic goals, then it is retained for inclusion in the Base Plan. See *Section II.E* for more detail.

The next step in the planning process is to *Identify the Base Plan*. This requires reoptimization of potential generating unit additions, taking into account the non-construction alternatives that have been identified in the previous step. The reoptimization is performed using FPL's base case, or most likely, planning assumptions, and includes strategic considerations as well as a detailed economic evaluation. The Base Plan identified through this process represents the optimum series of unit additions to meet the capacity need that remains after implementation of non-construction alternatives. *Section II.F* provides more detail on the identification of the Base Plan.

The Base Plan is then subject to *Scenario and Sensitivity Analyses*. The scenario analyses examine the Base Plan under alternative scenarios to the base case planning assumptions, while the sensitivity analyses test the Base Plan by varying key assumptions, such as fuel availability. These analyses provide a measure of how well the Base Plan performs in light of the inherent uncertainty in future assumptions. This step in the planning process is described in more detail in *Section II.G*. Strategic considerations are used throughout the analyses. These considerations are discussed in *Section II.H*.

The balance of this section describes the methodology for the major steps of the planning process in more detail. The results of the various analyses are presented in *Section IV*.

B. Reliability Assessment

FPL uses both loss-of-load probability (LOLP) and percent reserve margin criteria in evaluating the impact of capacity additions on system reliability. Reserve margin analysis accounts for peak load, installed generation, power purchases/sales and load management considerations. The LOLP analysis, in addition to the elements included in the reserve margin analysis, also considers tie line assistance, daily load variations and unit characteristics. Tie line assistance is the use of transmission interconnections to obtain power from neighboring utilities to maintain system integrity. Table II.B.1 summarizes the variables considered in each methodology.

The LOLP analysis conducted by FPL uses the TIGER (Tie Line Assistance and Generation Reliability) program as the analysis tool and an assisted LOLP of .1 day/year as the threshold criterion for need. This criterion is generally accepted throughout the utility industry and it has been recognized by the FPSC in the statewide Annual Planning Hearings. The assisted LOLP, as analyzed by the TIGER program, is dependent on the interaction of many variables, such as those shown in Table II.B.2.

	Considered In Calculation	
Variable	Reserve Margin	Loss-Of-Load Probability
Unit Characteristics		
· Size	No	Yes
· Maintenance	No	Yes
· Forced Outage Rate	No	Yes
Tie Line Assistance	No	Yes
Daily Load Variations	No	Yes
Total Capacity*	Yes	Yes

* Includes Firm Purchases, Load Management, Qualifying Facilities and Interruptible Load

Table II.B.1

Tie line assistance can be provided to the FPL system by other utilities in Florida or by the Southern Companies and other interconnected utilities. The tie line assistance is dependent not only on the transmission ties into FPL's system from its neighbors, but also on transfer capability within the FPL system (predominantly the transmission capability from the north to the south).

Variables Considered By Tiger When Analyzing Assisted LOLP

1. The load forecasts of FPL and assistance areas. The assistance areas include the Southern Companies and all other Florida utilities.
2. The existing generation and committed plans of the primary and assistance areas.
3. Firm purchase agreements of the primary and assistance areas.
4. The tie line transfer capability from the assistance areas to the primary area.

Table II.B.2

The geographic location of resources, whether those of qualifying facilities, independent power producers or other utilities, may have an impact on the amount of assistance that would be available to FPL from its neighbors. These resources may load the transmission system, thus reducing the tie line assistance capability.

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 over-reliance 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 change in growth rates and other unexpected developments. FPL uses 15% of summer peak load as a minimum acceptable reserve margin in determining the need for new capacity.

FPL's final determination of capacity needs is based on the more conservative of the two criteria, i.e., whichever indicates a need for more capacity. This approach assures that customer needs for reliable service will be adequately met.

The reliability assessment is initially performed without consideration of any incremental demand side programs, potential qualifying facilities, additional power purchases or new capacity additions.

These alternatives are evaluated against one another in later analyses and their reliability impact is taken into account at that time. Since conservation is treated as an adjustment to the load forecast, as discussed in Section III.A, the expected amount of total incremental conservation is added back into the demand and energy forecasts so that its reliability effect and economic benefit may be determined in the planning process.

C. Screening Evaluation

The purpose of the screening evaluation is to identify appropriate generation options prior to the detailed economic optimization analysis. Screening of options is basically a two step process. First, a broad list of capacity alternatives is pared down to a more manageable size based on considerations of availability in the required time frame (including licensing and construction lead time), technological maturity and technical feasibility for use in FPL's service area.

The second step in the screening evaluation is an economic comparison of the remaining options using "screening curves." These graphs illustrate the total revenue requirements of constructing and operating a generation option versus its capacity factor. Since the generation options would generally be of different sizes, these costs are normalized on a $/KW-year basis. There are two components to the total revenue requirements: capital and operating costs. The capital revenue requirements are calculated based on the capital costs of the generation option, as well as on FPL's projected cost of capital. The operating costs (fuel and maintenance) are levelized over a thirty year period following the expected in-service date. This is done so that different fuel prices, as well as the effect of different fuel price escalation rates, are included in the analysis. The operating costs are calculated over the full range of capacity factors. The resulting operating revenue requirements are then combined with the capital revenue requirements at each capacity factor. The result is a curve depicting the total levelized revenue requirements for each generation option as a function of the capacity factor.

Usually, the curves of similar generation options are displayed on the same graph. The points of interest on these graphs are any intersections between curves. The y-intercept of the curves shows the fixed cost of the generation option, including capital and fixed operation and maintenance. The slope of the curve is dependent upon the operating cost (fuel, heat rate and variable O&M). A steeper slope means greater operating costs. Figure II.C.1 illustrates how generation options are compared using "screening curves."

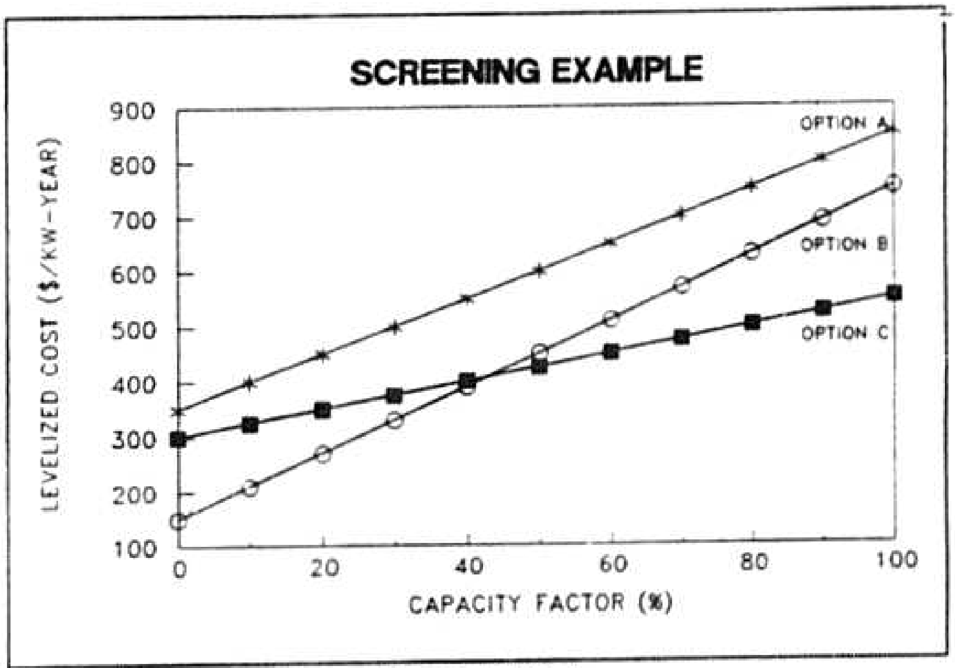


Figure II.C.1

When the curves for two similar generation options do not intersect at any capacity factor, it is a good indication that the capacity option described by the line having the higher costs (e.g., Option A) will be, from an economic point of view, a less desirable choice. Such options may be eliminated from the detailed economic optimization analysis. However, if the curves cross (e.g., Options B and C), then it must be decided whether the expected range of operation will occur beyond the crossover. If so, the option corresponding to the line representing the higher costs (e.g., Option B) may again be eliminated from the detailed economic optimization analysis. Through this process, the original list of capacity options may be reduced before proceeding to the economic optimization analysis. However, caution must be exercised in the use of this method of analysis. Important factors such as the effect on system operation and differences in unit availability are not included. Therefore, the results should be viewed as a preliminary screening only.

D. Creation Of The Reference Plan

As discussed in the previous section on reliability assessment, the timing and amount of FPL's capacity needs are first determined without incremental conservation, load management, interruptible load, non-contracted qualifying facilities and firm power purchases (i.e., without the 1988 Southern contract). A multi-step process is then used to create a *Reference Plan*, which is a plan designed to meet FPL's total capacity need solely by the addition of new units. This Reference Plan becomes the base line for evaluation of all alternatives to the construction of new units. As the first step in creating the Reference Plan, FPL identifies a number of alternative generation expansion plans that would meet system reliability requirements throughout the study period. Each of these expansion plans consist of combinations of the candidate units which were selected through the preliminary screening process. Second, FPL performs an economic optimization analysis of these alternative expansion plans and examines the results of that analysis in light of strategic considerations in order to determine which of these alternative plans best meets FPL's needs.

The economic optimization analysis is the heart of the generation expansion planning study. It is a detailed economic analysis with the objective of producing the most economical generation expansion plan while maintaining adequate generation system reliability. The reliability analysis produces a schedule of capacity requirements. Through the economic optimization analysis, the specific types of generation capacity are identified. The objective of the economic optimization analysis is to determine the total present value of revenue requirements (PVRR). The PVRR includes the capital, fuel and O&M costs for the new unit additions, as well as the fuel costs for the existing units in FPL's system. The PVRR is the accumulation of the annual nominal system revenue requirements over a period of thirty years, which is discounted to present value using a discount rate equal to the weighted cost of capital.

FPL chose to use the PROSCREEN program to do the economic analysis in coordination with the detailed reliability analysis program, TIGER. The TIGER program provides a very detailed reliability assessment and PROSCREEN provides an economic analysis that incorporates the following:

1. Annual revenue requirements of capital projects
2. Detailed production costing simulation
3. Limited fuel logic
4. Dual fuel unit capability
5. Interchange accounting
6. Extensive program documentation

See *Appendix E* for a further description of the computer programs used in the study.

E. Evaluation Of Alternatives To New Construction

Following the creation of the Reference Plan, several non-construction alternatives were tested for cost effectiveness against the unit addition schedule identified. The alternatives, shown in Table II.E.1, displace units in the Reference Plan to the extent they are cost effective and adequately address strategic considerations. When all non-construction alternatives have been evaluated, the remaining units represent the total new capacity needs of FPL.

Alternatives Evaluated For Cost Effectiveness
• Incremental Conservation
• Load Management
• Interruptible Load
• Potential Qualifying Facilities
• Power Purchases from Southern Company

Table II.E.1

F. Identification Of The Base Plan

The series of new unit additions that remains after the incorporation of non-construction alternatives is reoptimized to produce a Base Plan. The methodology used to perform the reoptimization is similar to that used to create the initial Reference Plan. A number of alternative expansion plans are identified that would meet the remaining capacity need throughout the study period. These plans consist of units, including repowering, that survived the preliminary screening. These combinations are then subjected to economic and strategic analyses in order to select the Base Plan that meets FPL's needs in the most cost effective manner consistent with strategic considerations. *Section II.H* describes the strategic factors considered in FPL's planning process.

By giving full consideration to both non-construction and construction alternatives, FPL's planning process results in identification of a combined resource plan that includes a balance of all generating and nongenerating alternatives.

C. Scenario And Sensitivity Analyses

The final phase of the planning study involves testing the Base Plan under a number of alternative assumptions. A scenario is a coordinated set of assumptions which describe all conditions associated with a particular case. For example, a pessimistic fuel price scenario would reflect not only higher fuel prices, but also the corresponding changes in the economic and load forecasts. A sensitivity analysis is an evaluation in which only one variable at a time is changed to determine the impact of each change on the Base Plan.

FPL has tested the Base Plan under the following alternative scenarios and sensitivities:

Alternative Scenarios

- Effective OPEC Cartel (Pessimistic Fuel Price)
- Oil Shock

Sensitivities

- Lower Natural Gas Availability
- Lower Economy Energy Availability
- Gasification "Break Even"
- High Load

In each case, the economics of the Base Plan were reexamined against alternative expansion plans.

H. Strategic Considerations

In developing a power supply plan, consideration of economics alone would fail to recognize the changing environment which will most certainly exist through time. Therefore, the expansion plan which is considered to be lowest cost may or may not be an "optimal" plan, depending on its ability to deal with other more qualitative issues. FPL believes that it is appropriate to pursue a balanced approach to meeting future needs, recognizing both economics and risk. To achieve this balance, FPL's analysis includes consideration of a number of strategic factors.

Some of the strategic factors which are considered in the planning process are shown in Table II.H.1. A more comprehensive discussion of each of these considerations follows. *Section IV* shows how these factors were applied in the power supply planning process.

Strategic Factors Considered
In The Planning Process

- Protection of the environment
- Conservation of natural resources
- Customer retention and customer choice
- Economic risk to the customer
- Fuel flexibility
- Flexibility to respond to changes in demand growth
- Operational flexibility
- Financial integrity of FPL
- Regulatory uncertainty

Table II.H.1

Protection Of The Environment

One of the most important considerations in the development of a power supply plan is environmental impact. Environmental regulations and emerging issues must be carefully analyzed in evaluating generating options. While two power supply alternatives may be economically competitive, their effects on the environment may be quite different.

Conservation Of Natural Resources

The conservation of natural resources, such as coal, natural gas and oil, must be an objective of power supply planning. Conservation of these resources requires both supply side efforts to maximize the efficiency with which such fuels are used in the production of electricity, and demand side efforts to increase the efficient use of electricity.

Customer Retention And Customer Choice

Consideration must also be given to the uncertainties introduced by the awareness of the customer to the choices offered in an increasingly competitive environment. This environment necessitates the introduction of options which allow the customer to choose a desired level of service at a corresponding price. Options such as interruptible rates and load management are an important part of the power supply plan to meet customer needs.

Economic Risk To The Customer

Alternative expansion plans are often compared on a total present value of revenue requirements (PVRR) basis. It is important, however, to compare not only the "bottom line," but also the year by year economics of alternatives. A plan which is lower cost in year thirty, but does not produce savings until year twenty-nine, may not present the best economic choice to the customer. Particularly when savings are predicated on fuel price differences, results should be carefully examined before a decision is made. Reliance on fuel savings to offset higher capital costs introduces a high degree of risk to both shareholders and customers. An expansion plan must therefore carefully consider the risks associated with relying on fuel savings to offset initially higher capital costs.

Fuel Flexibility

Recent events have clearly demonstrated the volatility of the fuels market. The price and availability of fuels, most notably oil and gas, have shown dramatic swings over the past few years. These swings influence the results of the power supply planning study, affecting both type and timing of units.

In evaluating supply options, consideration must also be given to changing price relationships between competing fuels. Power supply plans are developed assuming certain long range price relationships between competing fuels. In identifying a preferred plan, it is important for the planner to realize that the conditions upon which a decision is based are subject to change after a course is set. When fuel price relationships change to the point where the economics of a supply are significantly altered, the ability to switch fuels would benefit the utility and the ratepayer. There is an emphasis, therefore, on developing a power supply plan that maintains the ability to respond to changing fuel price conditions.

It is important in discussing fuel flexibility to distinguish between a unit which is capable of burning several different fuels at the time it is put into service and a unit which can be "converted" to burn different fuels. Both could be considered "fuel flexible." However, the capital costs may be quite different and this difference must be factored into any comparison between the units. For example, a coal unit capable of burning oil or gas may be considered to offer approximately the same fuel flexibility as a combined cycle unit capable of burning natural gas or coal. However, a large portion of the capital cost of the coal burning combined cycle unit may be deferred until it is economically attractive to burn the coal, while practically all of the capital cost of the coal unit must be committed up front whether or not the additional fuel capability is used.

Flexibility To Respond To Changes In Demand Growth

Uncertainty over demand growth must also be considered when a power supply plan is developed. Options with short installation/construction lead times and modular construction allow the utility to respond to changes in the demand forecast. Options which have long lead times introduce significant risk into a plan by making it more difficult to respond to change. In many cases, this will also impact the financial risk associated with the plan. Modular construction, meaning the unit can be constructed in "pieces," also enhances the utility's ability to respond to changes. An example would be a combined cycle unit, which consists of one or more combustion turbines and a steam turbine generator. These components can be "phased in" to match the pattern of demand growth.

Operational Flexibility

When a number of diverse alternatives are compared, consideration needs to be given to the operational requirements of the system. Particularly where non-utility supply sources are evaluated, the following factors should be accounted for in the analysis:

- Unit dispatchability
- System voltage regulation
- System reactive requirements
- Transmission constraints
- Unit cycling requirements imposed by load patterns

Financial Integrity Of FPL

Financing and rate relief are major considerations that must be analyzed before a plan is adopted. Any power supply plan requires a financial analysis to determine if adequate financing can be expected to be available at a reasonable cost. The availability of financing is dependent on the financial integrity of FPL, which is reflected in its debt coverage ratios, return on equity and capital structure.

In a business such as FPL's, investors must perceive that their investment will earn a rate of return comparable to that available from companies of similar risk. Adequate revenues producing a fair rate of return on the investment are essential to attracting investment to FPL. Such investments are needed to meet the following facility requirements: 1) replacement of existing lines, poles, cables and power plant components as they wear out or become obsolete, 2) environmental control equipment, 3) capital improvements to facilities to enhance efficiency, 4) investment in fuel stocks to obtain supply security and stability, 5) demonstration projects for new technology, 6) capital investment to maintain flexibility of fuel supply and 7) new facilities to accommodate load growth.

Regulatory Uncertainty

Regulatory considerations represent significant issues in the power supply planning process. As a result of a myriad of regulatory requirements, numerous uncertainties are created in the overall planning process. These uncertainties can impact the cost and timing of potential options. One of the main responsibilities of the power supply planner is to assess existing and proposed Federal and State regulations in order to develop an expansion plan that properly addresses these considerations.

Both nuclear and fossil generating plants have to meet State and Federal regulations. On the Federal level, there are several agencies, such as the Nuclear Regulatory Commission (NRC) and the Environmental Protection Agency (EPA), which have approval authority over the design and construction of power plants. Likewise, on the state level, generation additions have to meet the standards set forth by the Florida Department of Environmental Regulation (FDER) and other state, regional and local agencies. Also on the state level, the Florida Public Service Commission (FPSC) must make a determination of need for any proposed power plant.

The end effect of these regulatory requirements is the creation of uncertainties in the planning process with regard to capital costs, lead times for site selection and plant construction. The capital costs of a new generating plant may be increased by additional equipment necessary to meet regulatory requirements. For example, scrubbers and electrostatic precipitators are now required on all new coal fired power plants. Future legislation may result in even more stringent requirements that would significantly increase the costs of new generating units.

The lead time, or time for construction of a new plant, has also been significantly affected by regulations. A plant that might have been built in five years in the past may now take ten years to site, license, design and build, due to more comprehensive licensing procedures and required studies. Longer lead times increase the uncertainty of timely completion of generation projects and thus, affect the overall reliability of the system. In addition, extended lead times increase the financial risk of a project, as well as the possibility of cost overruns.

Until 1987, the Power Plant and Industrial Fuel Use Act (FUA or Act) prohibited the use of natural gas or petroleum in new electric power plants unless an exemption was obtained from the Department of Energy. In 1987, the Act was amended to remove all restrictions on construction of peak and intermediate load power plants and to allow construction of base load power plants using natural gas or petroleum if the plants are also coal capable. Under the definition of coal capability provided in the Act, a base load power plant need not be capable of burning coal immediately upon operation. The power plant must have inherent design characteristics to permit the addition of equipment necessary to render the power plant capable of using coal in the future and not be physically, structurally or technologically precluded from burning coal. The alternative generation technologies considered by FPL satisfy these requirements.

I. Consistency With Peninsular Florida Needs

The generation additions in the Base Plan are compared with the Peninsular Florida needs identified in the FCG's most recent statewide planning study. This comparison is designed to ensure that the plans are generally consistent and to explore the reasons for any inconsistencies.

III. ASSUMPTIONS

Power supply plans are based on a number of forecasts and assumptions. One of the major parameters that drives the timing of FPL's need for additional capacity is the summer peak load forecast. Once a need for additional capacity has been identified, the development of an optimal power supply plan depends on a number of factors, including the availability of non-generating alternatives, the capital and operating costs of the various generating options, the fuel price forecast, the utility's cost of capital and the utility's mix of existing resources. This section discusses each of the major forecasts and assumptions that serve as inputs into the planning process.

A. Load Forecast

FPL prepares long term twenty year forecasts of customers, sales and net energy for load, and summer and winter peak demand using a variety of load forecasting techniques. These include regression analysis, time series analysis, end use models and load duration curve analysis. FPL's "most likely" forecast is based on most likely assumptions about factors such as population, price of electricity and weather. There is nonetheless a great deal of uncertainty in any forecast which must recognize economic, demographic, technological and social changes. Therefore, in addition to the scenario of most likely conditions, alternative scenarios are developed to take into account optimistic and pessimistic assumptions about the economy and customer growth. These alternative scenarios are used to develop high and low band forecasts. The following is a brief summary of the long term forecast methodology, input assumptions and results. See *Appendices B and C* for more detail on FPL's load forecast.

Forecast Methodology

- *Customers*

  Customers are forecast by revenue class. The Residential customer forecast is based on projections of population and household size. Commercial, Industrial, and Street and Highway customers are forecast using econometric models. Specific projections are made for the number of customers in the Other Public Authority and the Railroads and Railways classifications.

- *Sales*

  Residential sales are forecast using an integrated end use/econometric model developed by EPRI and known as the Residential End Use Energy Planning System (REEPS). Typical input requirements in REEPS are the price of electricity, weather variables, appliance saturation and household vintage. REEPS incorporates FPL's Home Energy Survey and Residential and Demographic Survey data as input into the customers' household appliance purchases. The REEPS model output is adjusted to reflect the conservation induced by FPL's conservation programs.

  Commercial sales are forecast using the Commercial End Use Model (COMMEND), also developed by EPRI. COMMEND forecasts commercial energy requirements by disaggregating the commercial sector into building types, end uses and fuel types and then examining trends in these components.

  Industrial sales are forecast using a linear multiple regression model that incorporates Florida manufacturing employment and FPL service territory population as explanatory variables.

  Resale (wholesale) sales are comprised of three categories which are forecast separately. The forecast of sales to Seminole

Electric Cooperative is based on Seminole's service obligation, regression analysis and load duration curve analysis. The forecast of sales to full requirements customers other than Seminole is based on state space modeling. The forecast of sales to partial requirements customers is based on contract demands from the customers and historical usage patterns.

Sales forecasts for these and other classes are summed to produce a total sales forecast. Transmission loss estimates, which are based on FPL's most recent cost of service study (1987), are then applied to the total sales forecast to forecast annual net energy for load.

- *Peak Demand*

Summer peak demand per customer is forecast using a multiple regression model. Explanatory variables include the real average price of electricity, real per capita income, and a weather term multiplied by the stock of air conditioning appliances. The output of the demand-per-customer model is multiplied by the forecast of FPL summer customers to obtain total summer peak demand values.

Winter peak demand is forecast using the same methodology. The multiple regression model for winter peak demand-per-customer uses price of electricity, weather, and heating appliance saturations as explanatory variables.

Embedded conservation and future non-utility induced conservation are implicit in the regression models used to forecast peak demands. In addition, adjustments are made to the output of these models to reflect the incremental impacts of utility induced conservation.

Forecast Assumptions

The assumptions which drive the customer, energy and load forecasting models come from both internal and external sources. For example, FPL's current service territory population forecast was prepared by combining FPL's internally estimated share of each county served with the average of the mid-band and high-band county population forecasts by the Bureau of Economic and Business Research (BEBR). Similarly, economic projections combine FPL's internal estimates with data from outside sources such as Data Resources, Inc. (DRI). The assumptions used in the creation of FPL's 1989 forecast are shown in Table III.A.1.

Assumptions Used In The Creation Of FPL's 1989 Forecast

FPL Service Territory Population
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-1988	----	3.1%	----
1988-1998	1.8%	2.3%	2.8%
1988-2008	1.5%	2.0%	2.5%

Household Size In FPL Service Territory
Compound Average Annual Growth Rate

Years	Most Likely
1978-1988	-0.9%
1988-1998	-0.6%
1988-2008	-0.5%

Florida Real Personal Income
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-1988	----	5.1%	----
1988-1998	2.8%	3.3%	3.8%
1988-2008	2.7%	3.1%	3.6%

Real Average Price Of Electricity For Total Customers
Compound Average Annual Growth Rate

Years	Most Likely
1978-1988	0.5%
1988-1998	-0.7%
1988-2008	-0.6%

Table III.A.1

As shown in Table III.A.1, population in FPL's service area is expected to continue to grow over the next twenty years. The compound average annual growth rate (CAAGR) is expected to be 2.0% per year, down from the 3.1% level experienced during the last decade. Household size is projected to be 1.99 persons in 2003, down from 2.20 in 1988. This reduction in household size results from an aging population and demographic changes in households.

Forecast Results

The historical and forecast average annual growth rates in customers, demand and energy are summarized in Table III.A.2.

FPL's 1989 Forecast Results

Total Customers
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-1988	----	4.1%	----
1988-1998	2.5%	3.1%	3.7%
1988-2008	2.1%	2.7%	3.2%

Demand: Summer Peak
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-1988	----	4.0%	----
1988-1998	2.0%	2.7%	3.4%
1988-2008	1.8%	2.4%	2.9%

Net Energy For Load
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-1988	----	4.0%	----
1988-1998	2.3%	3.0%	3.7%
1988-2008	2.1%	2.7%	3.5%

Demand: Winter Peak
Compound Average Annual Growth Rate

Years	Low	Most Likely	High
1978-79/1988-89	----	3.9%	----
1988-89/1998-99	2.7%	3.4%	4.5%
1988-89/2007-08	2.7%	3.0%	3.5%

Table III.A.2

The population growth and household size projections used by FPL reflect a consistent decline in the customer growth rate over the forecast period. The compound average annual growth rate in total customers is expected to decline from 4.1% during the last decade to 2.7% over the next twenty years.

This decline in customer growth rate is reflected in the forecasted twenty-year growth rates of net energy for load (2.7%) and summer peak demand (2.4%), both of which are below the growth rates for the last decade.

The forecasts of customers, summer peak demand, winter peak demand and net energy for load are shown in Figures III.A.1, III.A.2, III.A.3 and III.A.4, respectively and the components of total energy sales are presented in Figure III.A.5. Additional detail on the forecast results and underlying assumptions is contained in *Appendices B and C*.

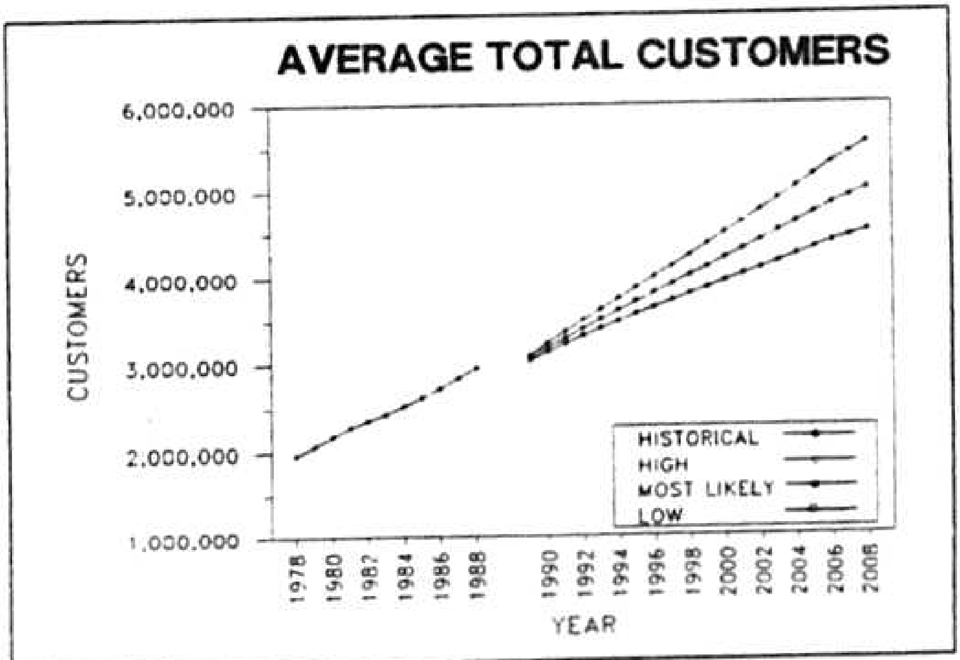


Figure III.A.1

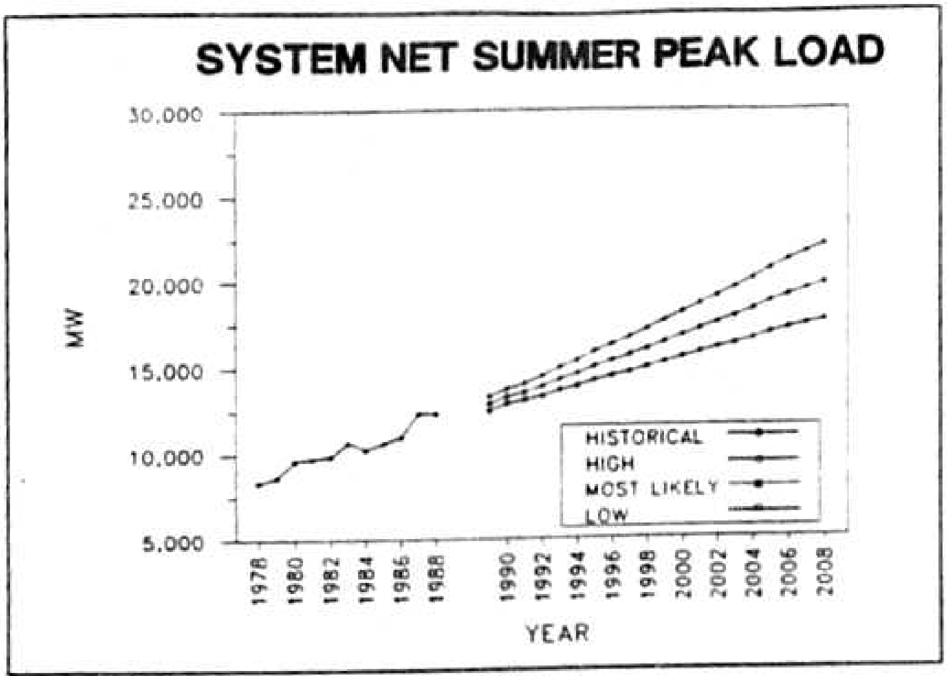


Figure III.A.2

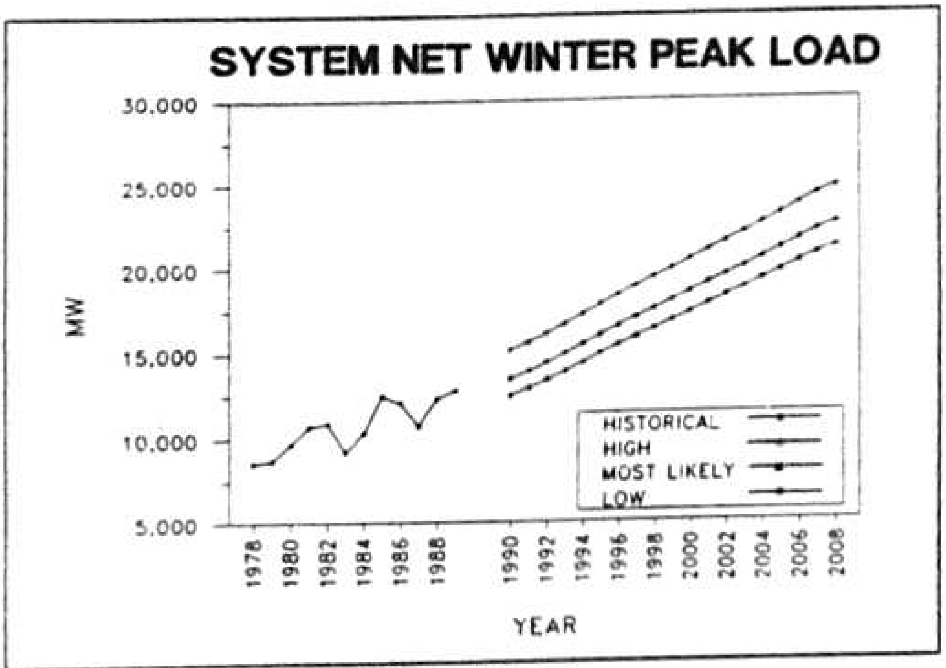


Figure III.A.3

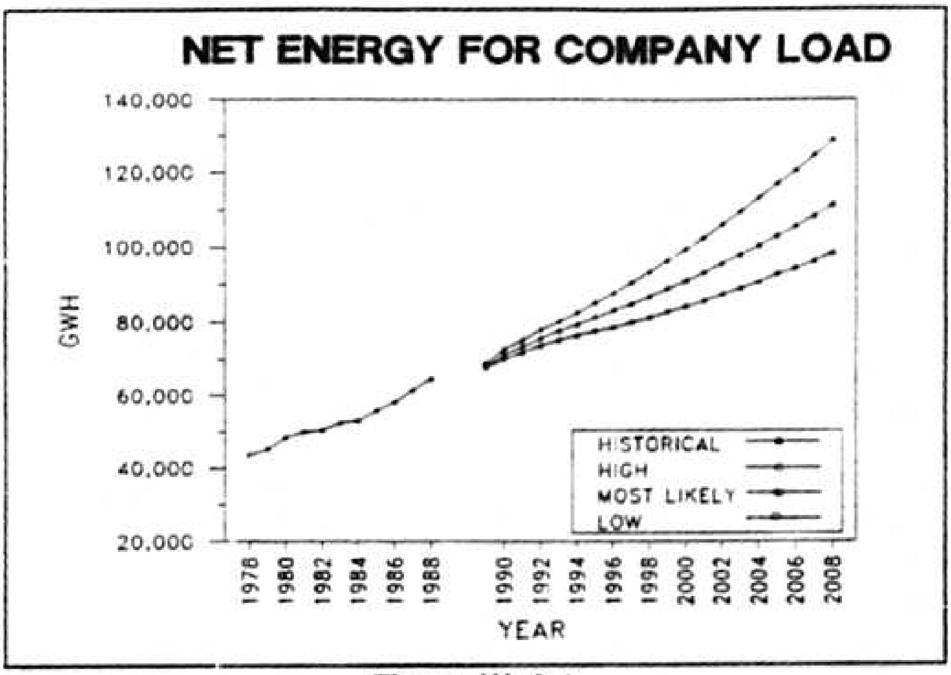


Figure III.A.4

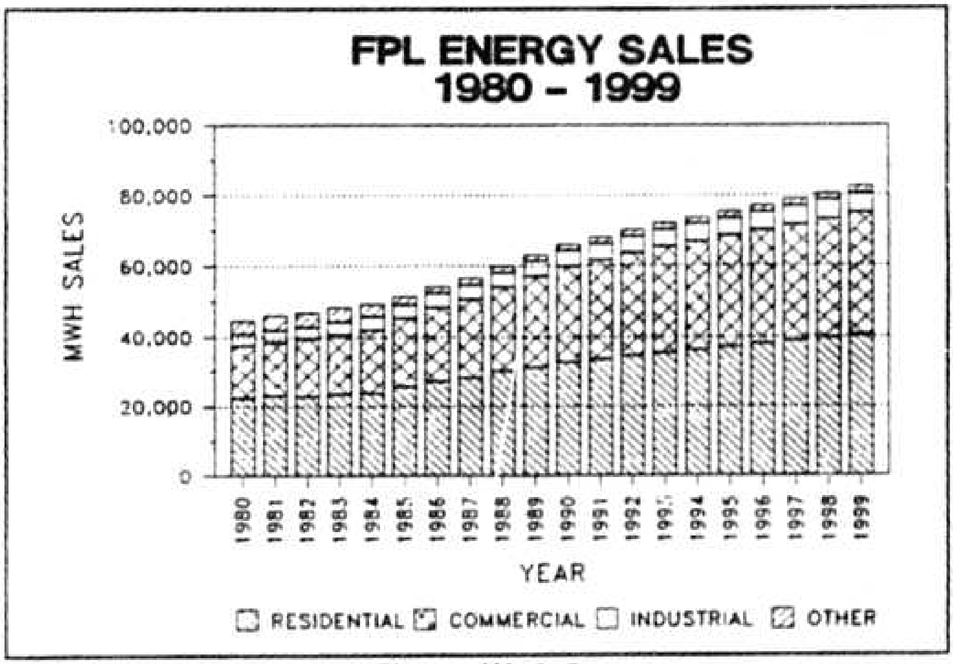


Figure III.A.5

B. Fuel Price Forecast

Fuel price and availability forecasts and the resulting projected price differentials between alternative fuels are major factors used in developing FPL's strategy for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published forecasts prepared at the same time.

Forecast Methodology

FPL uses a scenario approach to the development of long term fuel price forecasts. FPL develops a base case scenario, as well as alternative fuel price scenarios which reflect potential changes in the various fuel markets. Each scenario describes potential international and domestic events which can affect the supply, demand, and/or price of fuels over time. Scenarios are not predictions of specific events, but a description of potential market conditions which could result in different fuel prices and availabilities. The base case scenario describes market conditions which are considered the most likely to occur. The alternative scenarios are considered less likely to occur and describe market conditions which result in higher and lower prices, and different availabilities, than the base case. Together, these scenarios tend to bound the range of uncertainty in fuel price forecasts, and provide the mechanism to evaluate the study results under a reasonable range of price and availability forecasts. In addition, an oil shock scenario was developed to test the effect that a radical change in fuel markets would have on FPL's generation plan.

These scenarios are used to support the various price forecasts for crude oil and mine mouth coal. Forecasts for fuel oil and natural gas are then developed based on expected market price relationships between those fuels and crude oil. Real price forecasts are also prepared for fuel transportation costs. Delivered real fuel prices are derived by adding the fuel and transportation components. The resulting forecasts are multiplied by FPL's forecast of the GNP implicit price deflator developed for each scenario to produce nominal delivered fuel price forecasts. These final forecasts are reviewed to ensure reasonableness and consistency. A more detailed description of FPL's fuel forecast methodology is contained in *Appendix D*.

Oil And Gas Scenarios

The primary factor that differentiates the most likely oil and natural gas price forecast from the alternative oil and natural gas price scenarios is the degree of success the Organization of Petroleum Exporting Countries (OPEC) is projected to have in controlling the crude oil market. The most likely scenario assumes that a production sharing agreement between all OPEC members with varying degrees of adherence will exist throughout the thirty year forecasting horizon. This scenario also assumes that non-OPEC crude oil supply will decline slowly, but steadily, and that OPEC will regain control of the market by the early 1990's. This will contribute to a steady increase in the real (constant) dollar price of oil and natural gas through the 1990's. The rate of increase in the real price of oil and natural gas is expected to diminish in the late 1990's, as higher oil prices result in a resurgence in non-OPEC supply. The rate of increase in the real price of oil is expected to decrease even further after the year 2000, as non-OPEC production peaks, then declines for the remainder of the planning horizon and competition from alternative sources of energy replaces non-OPEC supply as the limiting factor in OPEC's ability to continue to increase the real price of oil. However, the rate of increase in the real price of natural gas will escalate rapidly after the year 2000, as the more rapid decline in domestic natural gas supply results in natural gas becoming a more premium product, competitive with No. 2 oil in the heating oil market.

The effective OPEC cartel scenario assumes that a more restrictive production agreement is implemented and observed by all OPEC and some non-OPEC countries, which maintains world oil supply at a level sufficiently low to force supply and demand to reach equilibrium at a higher price than in the most likely case. These assumptions contribute to significantly higher oil and natural gas prices throughout the planning horizon.

The ineffective OPEC cartel scenario assumes that OPEC is unable to adhere to an effective production sharing agreement and that "production cheating" and "price discounting" are extensive. Under this scenario, all member nations would compete for market share and raise production to the level necessary to meet internal financial and political requirements. This level of competition would result in relatively low oil prices throughout the planning horizon. However, since most of the natural gas used in the U.S. is domestically produced, and since low energy prices would lead to lower exploration and development expenditures in the United States, natural gas availability would be significantly reduced under this scenario. This would result in natural gas prices rising much faster than oil prices.

Coal Scenarios

The primary factor that differentiates the most likely mine mouth coal price forecast from the alternative coal price scenarios is the degree of success the domestic coal industry will have in increasing or maintaining its share of the boiler fuel market at the expense of oil and natural gas. The most likely scenario assumes that the demand for coal will remain constant through the early 1990's then increase slowly to partially fill the additional capacity requirements in the boiler fuel markets. FPL's projection of abundant domestic supplies of coal in all sulfur grades and a very competitive market with chronic excess production capacity leads to the conclusion that the real (constant) dollar mine mouth price of coal will decline slightly through the early 1990's. As demand increases in the mid-1990's, the real price of coal should increase slowly as more costly mines are opened to meet a growing demand.

The high (mine mouth) coal price scenario, which is consistent with the effective OPEC cartel scenario, assumes that the demand for coal will remain constant through the early 1990's, then increase more rapidly than in the most-likely scenario to fill the additional capacity requirements in the boiler fuel market as end-users switch from high cost oil and natural gas. As a result, coal prices will remain essentially unchanged in real (constant) dollars terms through the early 1990's then increase slowly as more costly mines are opened to meet a growing demand. In general, mine mouth coal prices will only be slightly higher than in the most likely case as suppliers attempt to capture a portion of the increase in oil and natural gas prices without giving up their market share to a competing coal company.

The low (mine mouth) coal price scenario, which is consistent with the ineffective OPEC cartel scenario, assumes that the demand for coal would remain constant through the late 1990's, then increase at a slower rate than in the most likely scenario to only partially fill the additional capacity requirements in the boiler fuel markets as industry responds to the lower cost of alternate fuels. As a result, coal prices will decline through the mid-1990's then increase slowly as more costly mines are opened to meet a growing demand. In general, mine mouth coal prices will only be slightly lower than in the most likely case as the coal industry tries to maintain market share in light of relatively low cost oil.

A forecast of coal transportation costs was developed assuming a competitive delivery situation. Scenarios consistent with the most likely and alternate oil, natural gas and coal price scenarios were developed.

Oil Shock Scenario

The oil shock scenario is essentially the same as the most likely scenario until 1993, at which time there would be a major disruption in crude oil supply, such as an upheaval in a major Middle Eastern producing country which is postulated to last about six years. This would cause a sudden and radical imbalance between crude oil supply and demand. The resulting oil shock price forecast would mirror the 1979 run-up in prices and the subsequent market changes through 1988. After the initial price rise, prices would level off. Demand for petroleum products will decline as the market adjusts to higher prices through conservation and fuel switching, and OPEC countries will reduce supply, attempting to maintain higher prices. By the seventh year of relatively high prices, Middle Eastern OPEC countries would find themselves producing at levels which would not meet their revenue needs. To compensate for reduced revenues, several Middle Eastern countries would begin to increase production. As a result, supply would exceed demand and prices would plummet by the year 2000. After a short adjustment period during which time OPEC would regain some control over its members' production volumes, the price forecast under this scenario returns to the most likely forecast (in the year 2002).

A comparison of the projected prices of high sulfur coal delivered to the Martin Site, distillate fuel oil and natural gas is shown in Figure III.B.1 for the oil shock scenario.

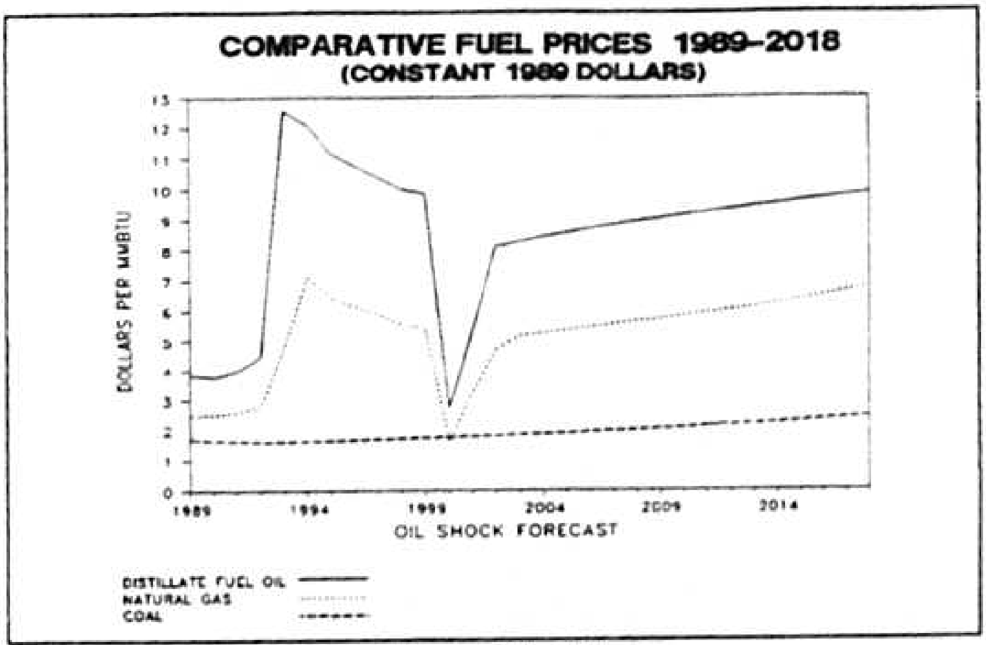


Figure III.B.1

Residual fuel oil and natural gas prices would follow the same pattern as crude oil prices, while coal would be relatively unaffected and forecasted coal prices would be only slightly higher than in the most likely scenario.

Forecast Results

A comparison of the projected real prices of high sulfur coal delivered to the Martin Site, distillate fuel oil and natural gas are shown in Figures III.B.2 through III.B.4 for the most likely, ineffective OPEC cartel, and effective OPEC cartel scenarios, respectively. These comparisons indicate a trend toward an increasing differential between the cost of coal, and natural gas or oil.

The detailed fuel price forecasts for these fuels, together with forecasts for coal delivered to SJRPP, 0.7% sulfur residual fuel oil and 1.0% sulfur residual fuel oil are presented in tabular form in *Appendix D*.

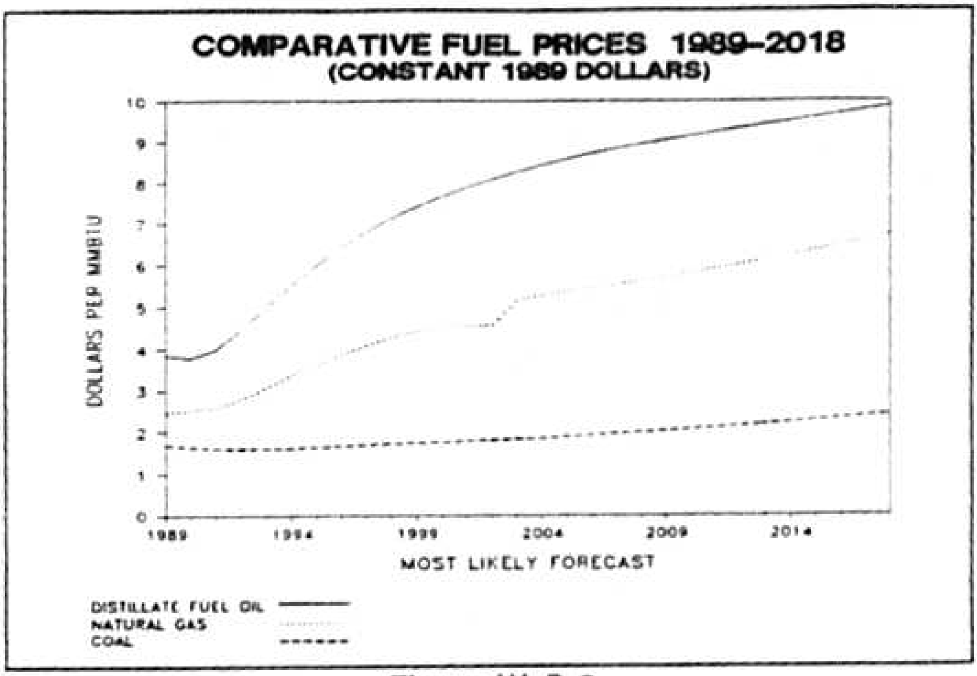


Figure III.B.2

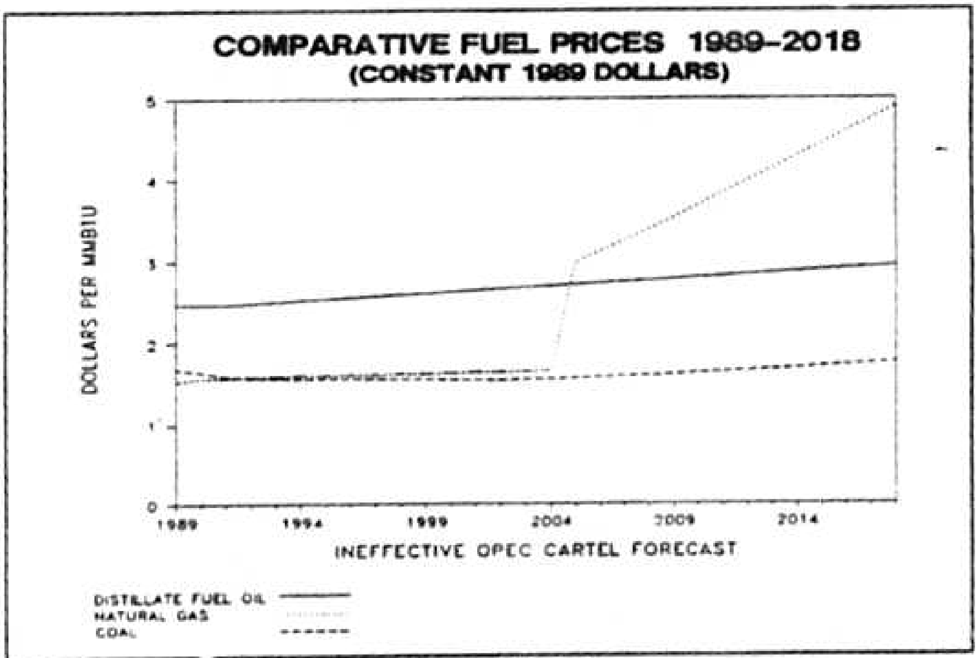


Figure III.B.3

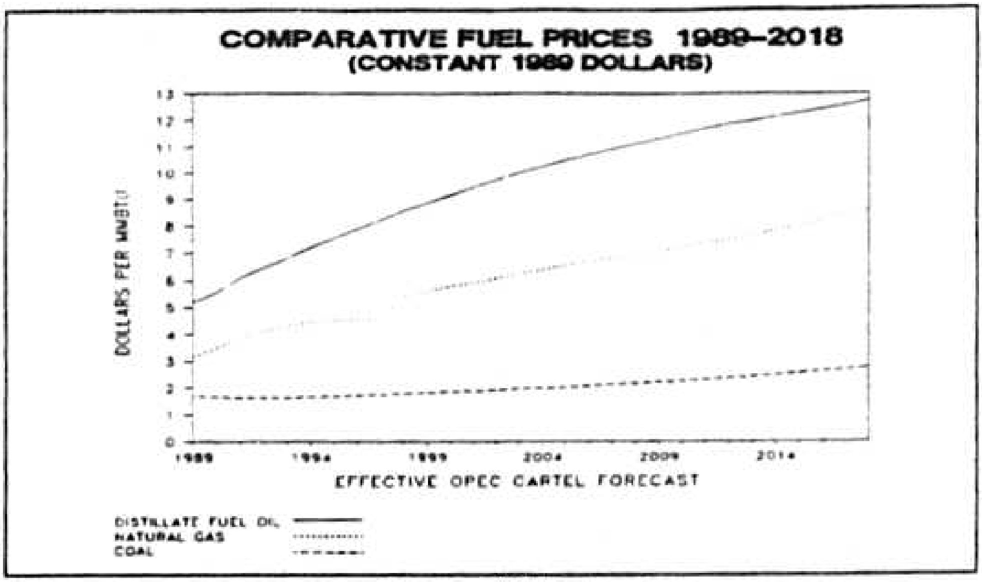


Figure III.B.4

C. Fuel Supply And Availability

Natural Gas

Natural gas is the primary fuel for the repowered Lauderdale Unit Nos. 4 and No. 5 and for the Martin Combined Cycle Unit Nos. 3 and 4. The back-up fuel for both sites is distillate fuel oil. It is anticipated that the back-up fuel will only be used in the event of natural gas supply disruptions. A summary of the natural gas volumes projected to be delivered to FPL under the various scenarios is presented in *Appendix D*.

On January 13, 1989, Florida Gas Transmission Company (FGT) filed with the Federal Energy Regulatory Commission (FERC) for a certificate to become an "open access" (common carrier) pipeline. This certificate, as well as the Phase II expansion (to 925 million cubic feet per day) of the FGT system, are currently pending before FERC for approval. As a result of the open access filing, the existing FGT pipeline capacity (Phase I) will be reallocated. Based on the proposed allocation plan submitted by FGT on May 13, 1989 to the parties involved in the Phase I settlement proceedings, FPL will receive sufficient firm gas transportation capacity to meet the natural gas requirements of the repowered Lauderdale Plant and the Martin Combined Cycle Unit Nos. 3 and 4. Citrus Trading Corp. (a subsidiary of Citrus Corp., jointly owned by Enron Corp. and Sonat, Inc.) will provide firm natural gas supplies.

Transportation of the natural gas to each plant site will be provided by FGT. Currently, both sites are connected to the FGT pipeline system. The pipeline lateral to the Lauderdale Site will be upgraded in the second quarter of 1991 and will have sufficient capacity to accommodate the repowered units. The existing pipeline lateral at the Martin Site does not have sufficient capacity to deliver the full gas volume requirements of the Martin Combined Cycle Unit Nos. 3 and 4. In order to provide an adequate gas supply, a new lateral will be constructed as discussed in *Section V.D* of this document.

Coal

The coal tonnage requirement for 800 MW of coal gas generation for the Combined Cycle Unit Nos. 5 and 6 at Martin will be approximately 2.3 million tons per year. This requirement would increase to approximately 4.5 million tons per year if the Martin Combined Cycle Unit Nos. 3 and 4 were retrofitted with coal gasification. The supply of this coal could come from either domestic or foreign producers, or both, with little or no impact on the domestic or foreign coal supply markets. The production capacity of the coal supply market is currently under-utilized and this situation is expected to continue through the late-1990's. As a result, it is expected that coal will be readily available. This condition of production capacity under-utilization exists for a broad range of coal qualities, spanning all sulfur grades.

A significant component of the cost of coal supply to any power plant is the cost of transportation and delivery. The cost of transporting and delivering coal can amount to from thirty to sixty percent of the total delivered cost of coal for power plants in Florida. A critical factor that determines the cost of transportation and delivery is whether there is more than one transportation and delivery alternative. Having more than one coal transportation and delivery alternative is also highly desirable in order to provide diversity, flexibility, and competitive transportation rates.

The Martin Site offers the desired flexibility. A six mile rail spur from the Florida East Coast Railway (FEC) main line enters the Plant property from the northwest. The FEC is a private, non-union railroad operating entirely within Florida, with a connection to the Norfolk-Southern railroad in Jacksonville, Florida. The Norfolk-Southern runs north into the Appalachian and Illinois coal fields. In addition to the FEC, one of the main lines of the CSX Railroad (CSX) in Florida runs adjacent to the northeast corner of the Martin Plant property. The CSX system extends into the Appalachian and Illinois coal fields. A spur of approximately one mile from the CSX main line to the plant would have to be built to enable CSX to deliver coal to the Plant.

The fact that the plant can be served by two separate, independent railroads both of which have access to the coal fields in Appalachia and Illinois, will provide competitive transportation rates, diversity and flexibility in coal transportation and delivery.

D. Financial And Economic Data

Several financial and economic parameters were used in the economic analyses of competing options. A summary of these assumptions is presented in Table III.D.1.

Summary Of Financial And Economic Assumptions
(For Long Range Planning Purposes)

Discount Rate: **12%**
AFUDC Rate: **12%**

Projected Capitalization Ratios		Projected Cost Of Capital	
Debt	44%	Debt	10.0%
Preferred	9%	Preferred	10.0%
Equity	47%	Equity	14.5%

Tax Assumptions

Rates:		Book Life:	
State	5.50%	Fossil Units	31 Years
Federal	32.13%[1]	Combustion Turbines	30 Years[2]
Effective	37.63%	Combined Cycle	30 Years
		Coal Gasifier	30 Years

Tax Depreciation Life: 20 Years

[1] State income taxes are deductible for federal tax purposes and thus, effectively reduce the federal tax rate from 34% to 32.13%.

[2] Designed with the capability of future conversion to combined cycle operation.

Annual Escalation Assumptions
(In Percent)

Year	General[1] Inflation	Plant[2] Construction Cost	O&M Cost[3]
1989	4.5	5.1	5.0
1990	4.5	5.0	4.9
1991	4.5	5.0	4.9
1992	4.6	5.1	5.0
1993	4.4	5.0	4.9
1994	4.9	5.1	5.0
1995	5.1	5.4	5.3
1996	5.3	5.5	5.4
1997	5.4	5.5	5.4
1998	5.5	5.6	5.5
1999-2015	5.4	5.6	5.5

[1] GNP Implicit Price Deflator (IPD)
[2] Producer Price Index (PPI) for Capital Goods
[3] Consumer Price Index (CPI)

Table III.D.1

E. Supply Side Options

Existing Unit Data

The data required for modeling FPL's generation system operations includes individual unit capacities, heat rates, forced outage rates, maintenance outage rates, O&M costs and fuel types. This individual unit data is used in conjunction with the fuel price and load and energy forecasts to calculate system production costs.

Data for existing units was based on historical performance and on the projected results of FPL's plan to decrease the forced outage rate of its fossil units. This plan is further described in *Section IV.B* of this document.

New Generation Options

The modeling of new generation options requires the same categories of data listed above, plus data on capital costs and construction cash flows which are used to calculate capital revenue requirements.

Table III.E.1 provides a summary of the planning data for the major generation options considered in this study. The cost and performance data associated with each generation option were developed by FPL with the assistance of architect/engineers, coal gasification process developers and recent studies by the Electric Research Power Institute (EPRI). The cost and performance data for the units to be constructed will change as engineering, design and licensing progress and component purchases occur. The amounts shown in this document will be updated accordingly. More detailed information on the units to be constructed is presented in *Section V.A*.

Although FPL considered a more extensive list of alternatives in the planning study, many were eliminated in the screening evaluation

(See *Section IV.C*). Only the options studied in detail are presented in Table III.E.1. Where capital or O&M costs vary between the first and second units installed at a single site, separate cost data is shown for both the initial unit and the extension unit.

F. <u>Interchange And Economy Power Purchases</u>

FPL's contracts for interchange and purchased power can provide a substantial portion of system energy requirements. To assure that forecasts of future energy production requirements reflect an appropriate contribution from interchange and purchased power sources, major categories are identified and included in modeling. For each category, energy cost and availability assumptions are provided as input.

The categories of interchange and purchased power include firm and non-firm (economy) sources. The firm sources are available to meet capacity requirements and are modeled in accordance with existing capacity contracts with the Southern Companies and the Jacksonville Electric Authority (JEA). The non-firm energy sources are modeled as energy available to offset the use of other higher cost generation sources. Such non-firm energy sources are not available to meet capacity requirements. The non-firm sources modeled include both intrastate and interstate economy energy.

FPL's major source of firm purchased power is from Southern. The Unit Power Sales Agreement (UPS) between FPL and Southern was executed in 1981 and amended in 1982. It includes provisions which require Southern to make best efforts to supply the contracted capacity at a 90% annual capacity factor. FPL's capacity entitlement is available for scheduling based on system economics subject to minimum purchase requirements as detailed in the Agreement.

Generation Options: Planning Assumptions

	Combustion Turbine (Advanced)	CT Repower (Advanced)	Combined Cycle (Advanced)	IGCC (Advanced)	IGCC (Advanced)	Pulverized Coal (Subcritical)	Pulverized Coal (Subcritical)	Pulverized Coal (Supercritical)	Pulverized Coal (Supercritical)
NOTES:	1	1	1	2	2	3	3	1	1
Unit	Initial/Extension	Initial/Extension	Initial/Extension	Initial	Extension	Initial	Extension	Initial	Extension
Site	Martin	Lauderdale	Martin	Martin	Martin	Martin	Martin	Martin	Martin
• Size, MW									
- (Net Summer)	125	572	385	768	768	624	624	750	750
• Fuel									
- Primary	Nat. Gas	Nat. Gas	Nat. Gas	Coal	Coal	Coal	Coal	Coal	Coal
- Back-Up	No. 2 Oil	No. 2 Oil	No. 2 Oil	No. 2 Oil	No. 2 Oil	None	None	None	None
• Heat Rate (BTU/KWH)									
- 100 %	11,416	7,578	7,620	8,701	8,701	9,739	9,739	9,449	9,449
- 75 %	12,044	7,736	7,600	8,957	8,957	9,862	9,862	9,667	9,667
- 50 %	13,644	8,585	8,230	9,220	9,220	10,301	10,301	10,221	10,221
• Reliability									
- F.O.R. (%)	6.0	0.4	0.4	2.6	2.6	5.0	5.0	9.5	9.5
- E.F.O.R. (%)	6.0	7.5	6.3	6.3	6.3	9.0	9.0	13.0	13.0
- Maint. (wk./yr.)	3.5	3.5	3.5	3.5	3.5	8.0	8.0	9.0	9.0
- Equiv. Av. (%)	87.0	86.0	87.0	87.0	87.0	75.6	75.6	70.0	70.0
• O&M[4/]									
- Fixed ($/KW-yr.)	8.55	13.30	14.25	40.75	30.60	24.54	24.54	14.85	13.79
- Var. ($/MWH)	0.44	0.91	0.58	0.92	0.69	2.43	2.43	2.65	2.45
• Capital[4/]									
- $/KW	441	611	533	1,376	1,078	1,315	1,030	1,190	931
• Schedule									
- Lic./Eng. (months)	24	30	37	48	48	48	48	48	48
- Construction	18	22	28	33	33	60	48	52	47
• Cash Flow[4/] ($000)									
- Year 1	228	12,340	5,849	6,342	3,083	2,051	1,608	1,153	782
- Year 2	4,858	37,863	13,029	26,956	13,575	4,103	4,822	6,641	3,864
- Year 3	21,160	171,205	33,930	120,509	61,410	6,566	6,751	12,874	18,780
- Year 4	26,817	81,688	68,485	206,473	137,890	9,848	11,574	31,389	57,422
- Year 5	--	39,843	63,500	369,985	218,188	28,313	88,406	71,860	106,550
- Year 6	--	6,513	20,215	215,119	262,772	125,559	183,242	155,156	159,616
- Year 7	--	--	--	77,182	112,590	221,575	176,812	304,561	203,965
- Year 8	--	--	--	4,530	18,765	213,369	121,840	248,774	126,220
- Year 9	--	--	--	--	--	151,820	47,900	59,810	20,915
- Year 10	--	--	--	--	--	57,445	--	--	--
Total	55,063	349,452	205,008	1,057,096	828,073	820,648	642,955	892,218	698,314

Notes:

1/ Source: FPL Project Management
2/ Source: FPL/EPRI IGCC Study (Fluor)
3/ Source: EBASCO, JEA, System Planning
4/ All Cost Estimates Are Expressed in 1989 $

Table III.E.1

The forecasted energy rates used as input to the production cost model were based on data provided by Southern Company Services (SCS). The energy rates shown in Table III.F.1 are the resulting average costs as dispatched by the production cost model.

Forecasted Energy Rates For 1982 UPS Agreement

Year	$/MWH
1989	22.48
1990	21.79
1991	21.39
1992	21.06
1993	21.69
1994	23.53
1995	23.75

Table III.F.1

In January, 1988, FPL and SCS executed a letter of intent to negotiate an agreement at a level of 700 MW from June, 1995 through May, 2010. In July, a contract was signed at a level of 900 MW from June, 1995 through May, 2010. Capacity charges for the 1988 contract are shown in Table III.F.2 and reflect the expected unit ratings provided by Southern. In order to verify the economics of this contract, it was treated as an alternative to new construction in the analysis which led to the development of the Base Plan. The history and projections of current capacity entitlements from Southern, based on the expected unit ratings, are shown in Table III.F.3.

FPL's other source of firm purchased power is a contract entered into in 1982 with JEA. This contract entitles FPL to a portion of JEA's capacity from the jointly owned St. Johns River Power Park units. FPL owns 20% and purchases an additional 30% for a combined 50% of the total capacity (i.e., 624 MW out of 1,248 MW) for the life of the plant. Since the available capacity is unit-specific, planned and unplanned outage data is included in modeling, in addition to forecasted energy costs, which are based on the fuel price forecast and unit performance data.

Southern Company Unit Power Sales
Florida Power & Light Company

CONTRACT MW CAPACITY AND CAPACITY COSTS

	1982 UPS Agreement			1988 UPS Agreement			Both Agreements		
	Average Annual MW	Capacity ($000)	Capacity ($/KW/Mo.)	Average Annual MW	Capacity ($000)	Capacity ($/KW/Mo.)	Average Annual MW	Capacity ($000)	Capacity ($/KW/Mo.)
1989	2,067.0	340,324	13.720	N/A	N/A	N/A	2,067.0	340,324	13.720
1990	2,065.0	376,136	15.179	N/A	N/A	N/A	2,065.0	376,136	15.179
1991	2,063.0	386,205	15.600	N/A	N/A	N/A	2,063.0	386,205	15.600
1992	2,067.0	396,428	15.982	N/A	N/A	N/A	2,067.0	396,428	15.982
1993	1,314.0	265,444	16.834	177.0	28,319	13.333	1,491.0	293,763	16.401
1994	724.0	149,589	17.218	392.0	67,762	14.405	1,116.0	217,351	16.215
1995	213.0	43,254	16.922	721.0	128,017	14.796	934.0	171,271	14.760
1996	N/A	N/A	N/A	911.0	160,454	14.677	911.0	160,454	14.677
1997	N/A	N/A	N/A	911.0	159,184	14.561	911.0	159,184	14.561
1998	N/A	N/A	N/A	911.0	158,904	14.536	911.0	158,904	14.536
1999	N/A	N/A	N/A	911.0	158,476	14.496	911.0	158,476	14.496
2000	N/A	N/A	N/A	911.0	158,028	14.455	911.0	158,028	14.455
2001	N/A	N/A	N/A	911.0	157,573	14.414	911.0	157,573	14.414
2002	N/A	N/A	N/A	911.0	157,443	14.402	911.0	157,443	14.402
2003	N/A	N/A	N/A	911.0	157,754	14.430	911.0	157,754	14.430
2004	N/A	N/A	N/A	911.0	158,648	14.512	911.0	158,648	14.512
2005	N/A	N/A	N/A	911.0	160,168	14.651	911.0	160,168	14.651
2006	N/A	N/A	N/A	911.0	161,243	14.750	911.0	161,243	14.750
2007	N/A	N/A	N/A	911.0	162,220	14.839	911.0	162,220	14.839
2008	N/A	N/A	N/A	911.0	164,286	15.028	911.0	164,286	15.028
2009	N/A	N/A	N/A	911.0	166,094	15.193	911.0	166,094	15.193
2010	N/A	N/A	N/A	380.0	71,036	15.578	380.0	71,036	15.578

NOTES:

- CAPACITY AVAILABLE AT MINIMUM 90% ANNUAL CAPACITY FACTOR
- N/A - NOT APPLICABLE

Table III.F.2

FPL Capacity Entitlements[1]
From Southern Company
(in MW)

Year	Long Term Power Purchases Winter	Summer	Unit Power Sales Winter	Summer	Total Winter	Summer
1983	300	300	353	353	653	653
1984	300	300	663	660	963	960
1985	300	300	1722	1718	2022	2018
1986	300	300	1727	1725	2027	2025
1987	0	0	2033	2033	2033	2033
1988	0	0	2050	2048	2050	2048
1989[2]	0	0	2050	2067	2050	2067
1990	0	0	2067	2064	2067	2064
1991	0	0	2064	2060	2064	2060
1992	0	0	2058	2072	2058	2072
1993	0	0	1723	1326	1723	1326
1994	0	0	1325	967	1325	967
1995	0	0	966	911	966	911
1996-2009	0	0	911	911	911	911
2010	0	0	911	0	911	0

1983 Winter = Winter, 1982-83

[1] Totals reflect total capacity entitlements resulting from agreements between FPL and Southern Company. Nominal contract MW values adjusted for actual 1988 unit ratings.

[2] Values for 1983-1989 are actuals

Table III.F.3

Non-firm sources modeled include both intrastate and interstate economy energy. Including these sources in the production model does not have any impact on the amount of capacity required, but reduces the utilization of other relatively higher energy cost capacity resources through their displacement by lower cost energy from other utilities. Table III.F.4 summarizes the assumptions for both interstate firm capacity purchases and economy energy availability through the year 2018. The projected economy availability is based on a forecast by Southern through May, 2010 and is further

Assumptions For Interstate Firm Capacity Purchases And Economy Energy Availability (Average Annual)

Year	Firm Peak Unit Power Sales (MW)	Available On-Peak Economy Sales (MW)	Available Off-Peak Economy Sales (MW)
1989	2,067	300	300
1990	2,065	300	300
1991	2,063	300	300
1992	2,067	300	300
1993	1,491	797	803
1994	1,116	1,184	1,184
1995	934	1,338	1,372
1996	911	1,225	1,400
1997	911	1,197	1,394
1998	911	1,109	1,381
1999	911	981	1,394
2000	911	919	1,084
2001	911	763	1,097
2002	911	706	1,088
2003	911	575	1,075
2004	911	219	1,031
2005	911	194	941
2006	911	291	1,034
2007	911	191	1,084
2008	911	178	1,044
2009	911	141	1,003
2010	380	312	1,466
2011	0	1,223	1,651
2012	0	1,123	1,651
2013	0	1,023	1,651
2014	0	923	1,651
2015	0	823	1,651
2016	0	723	1,651
2017	0	623	1,651
2018	0	523	1,651

Table III.F.4

constrained by tie line capability and firm purchases. The UPS off-peak capacity is assumed to become available for economy sales in 2011, however, only a portion of the on-peak UPS capacity is assumed to become available due to Southern's anticipated load growth. Projected seller energy prices were based on forecasts provided by Southern Company Services. The transaction price to FPL is based on a "split the savings" calculation between this energy price and FPL's incremental energy price at the time of the transaction.

FPL assumed 300 MW of on-peak intrastate economy (i.e., broker) availability throughout the study period. The projected energy costs are based on FPL's coal price forecast. The transaction price to FPL is also based on a split the savings methodology.

G. Qualifying Facilities

FPL expects that qualifying facilities (QFs) will continue to develop in the future due in part to the encouragement provided by Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the FPSC rules implementing the Federal Energy Regulatory Commission (FERC) regulations adopted under PURPA.

FPL has made a projection of the potential QF additions. This projection includes two general types of QFs: cogenerators and small power producers. Cogenerators are further divided into two types. One type of cogenerator is typically not a net producer to grid, as its generation is usually smaller than its total electrical requirements. This type of cogenerator is usually a non-dispatchable technology whose size is determined by the requirements of the customer. The other type of cogenerator is a net energy producer and electrical energy supplier whose generation capability is greater than its own total electrical requirement. The forecast of the generation contribution of this type of QF is considered on a "net to grid" basis. The demand impact of both types of cogenerator is accounted for in the load forecast.

The small power producers are shown as net producers of energy, as they typically provide most of their energy to the grid. The small power producer category includes such facilities as municipal solid waste-to-energy facilities, sugar mills and other biomass facilities (e.g., waste wood burners).

FPL develops a projection of QFs and their generation contributions on an annual basis. The projection is based on active projects known to FPL and an extrapolation of the trends which govern the economic feasibility of these projects. The specific data that has been developed for each project is based on FPL's current knowledge of that type of facility and estimates of its generation capability and electrical load requirements. In many instances, this information is supplied to FPL by the project owner or representative. This data will change through time, as more information becomes available for each type of project. FPL's projections are limited to today's known variables that influence the economics of these types of facilities. As these variables change and influence the economics of these projects, FPL's projection of QFs will be revised to reflect the most current conditions. The economics of specific QFs included in the forecast are unknown to FPL; therefore, their financial stability cannot be assured by the Company. A summary of the projected capacity to be provided by QFs for the 1989 through 1997 period is provided in Table III.C.1.

Year	Firm And Potential Firm Cumulative Summer (MW)	Firm[1] And Potential Firm Cumulative Winter (MW)	Cumulative[2] Annual Energy (MWH)
1989	0	0	853,200
1990	0	0	1,513,200
1991	0	0	1,841,200
1992	391	391	2,160,600
1993	616	616	3,908,000
1994	616	616	3,936,600
1995	991	991	5,213,256
1996	1,058	1,058	5,627,156
1997	1,095	1,095	5,854,056

Capacity And Energy Contributions From Qualifying Facilities

[1] 1989 Winter = Winter, 1989-90

[2] Includes as-available (non-firm) energy purchases from Qualifying Facilities

Table III.G.1

H. Demand Side Management

FPL's demand side management (DSM) efforts to reduce the growth in peak load basically consist of activities in three areas: conservation, load management and interruptible rates. FPL's DSM activities began in the late 1970's, continue today and are an important part of FPL's future plans.

The history of DSM at FPL has been characterized by an evolution of DSM activities. The nature of these activities has changed from the late 1970's to the present as the needs of FPL's customers have changed. Conservation programs represented FPL's initial offering of DSM options to its customers. Many of the original conservation programs continue to be offered today, while the appeal of other programs has diminished. New DSM options are examined and the most promising ones are then developed. For example, load management options began to be offered in 1987 and interruptible rates began in 1988. Both of these DSM offerings are expected to provide FPL with a substantial demand reduction capability in the 1990's. The cost effectiveness of new and continuing DSM programs is analyzed and discussed in *Section IV.E.*

Conservation

FPL's initial DSM program was the Watt-Wise Home Program which was introduced in the late 1970's to encourage the construction of energy-efficient new homes. The introduction of this program contributed greatly to the eventual development of the Model Energy Efficiency Code by the State of Florida. Since that time, FPL has introduced more than a dozen additional conservation programs and both the residential and commercial/industrial markets have been addressed.

In 1981, FPL began reporting conservation program results to the FPSC pursuant to rules adopted under the Florida Energy Efficiency and Conservation Act (FEECA). Table III.H.1 shows the cumulative energy and demand reductions from conservation programs as reported by FPL in accordance with this reporting requirement. The table shows that FPL has reported a cumulative summer peak demand reduction of approximately 600 MW and a cumulative annual energy reduction of

FPL Conservation Programs
Energy And Summer Demand Reductions*

Year	Cumulative Energy Reductions (GWH)	Cumulative Summer Demand Reduction (MW)
1981	61.3	19.0
1982	246.1	68.7
1983	546.3	148.7
1984	924.4	246.2
1985	1,312.0	355.1
1986	1,634.3	455.6
1987	1,925.5	549.7
1988	2,093.7	598.8

Source: FPL FEECA Report Database

*Load Management, Interruptible Rates and Cogeneration program results are omitted

Table III.H.1

over 2,000 GWH through 1988. FPL's current projections of the future contribution from conservation programs is discussed in the section entitled "Summary of FPL's Demand Side Management Results and Projections."

Load Management

FPL is currently implementing two load management efforts: the On Call Program and the Commercial/Industrial Load Control Trial Project. In addition, other load management options are under consideration.

On Call Program

FPL introduced its residential load control program, the On Call Program, in 1987. This voluntary program offers residential customers a monthly credit on their bill for allowing FPL to temporarily interrupt certain appliances and equipment (central electric air conditioners, central electric space heaters, conventional electric water heaters and swimming pool pumps), as needed. The program was initially offered in Dade County and expanded into Broward County and the Southwest Florida region in 1989. Expansion into the rest of FPL's service territory will soon follow.

The On Call Program had a demand reduction capability of approximately 24 MW during the summer of 1989. The current implementation plan for the On Call Program from 1990-1997 is shown in Table III.H.2.

On Call Program
Projection Of Energy And Summer
Demand Reduction Capability

Year	Cumulative Energy Reductions (GWH)	Cumulative Summer Demand Reduction (MW)
1990	3.7	77
1991	7.1	146
1992	11.1	228
1993	15.1	310
1994	19.6	402
1995	24.5	504
1996	29.6	610
1997	32.5	668

Source: Load Management Department

Table III.H.2

Commercial/Industrial Load Control
Trial Project

FPL introduced a one year Commercial/Industrial Load Control Trial Project in April, 1988. The Trial was designed to test the acceptability of a load control concept with FPL's largest commercial/industrial customers. Fourteen customers have participated in the Trial, which ended on March 31, 1989. The Trial's tariff will be in effect until March 31, 1990 unless the FPSC reaches a decision earlier on FPL's petition for approval of a permanent Commercial/Industrial Load Control Program.

The Trial has been a success and a demand reduction capability of approximately 82 MW was achieved during the Trial. However, the introduction of FPL's Interruptible Rates in mid-1988 caused several Trial participants to shift a portion of the load they had committed to the Trial over to Interruptible Rates. The demand reduction capability from Commercial/Industrial Load Control during the summer of 1989 was approximately 50 MW. A projection of the total demand reduction capability from Commercial/Industrial Load Control and Interruptible Rates is given below in the Interruptible Rates section.

Interruptible Rates

As mentioned above, FPL's Interruptible Rates offering began in 1988. Currently, seven customers are receiving service under these rates and they provided a demand reduction capability of approximately 47 MW during the summer of 1989. The current implementation plan for Interruptible Rates and Commercial/Industrial Load Control is shown on the next page in Table III.H.3.

FEECA Goals

As previously mentioned, FPL's DSM efforts throughout the 1980's have already achieved a summer demand reduction of over 700 MW, primarily from conservation. In addition, FPL's DSM programs are anticipated to contribute an additional 1,000 MW of demand reduction capability by the end of the 1990's. FPL views these as both a significant accomplishment to date and a serious on-going commitment to DSM implementation.

Interruptible Rates
Commercial/Industrial Load Control
Projection Of Energy And Summer Demand
Reduction Capability

Year	Cumulative Energy Reduction (GWH)	Cumulative Summer Demand Reduction (MW)
1990	50.0	175
1991	95.0	250
1992	156.4	335

Source: Load Management Department

Table III.H.3

However, when comparing this accomplishment with the FEECA goals, the results are mixed. FPL has generally achieved success in meeting the FEECA summer demand goals, but has had less success with meeting FEECA's winter demand and annual energy goals. FPL's analysis of its DSM efforts to date and the FEECA results have led it to file a September 14, 1988 petition to initiate rulemaking in regard to Rule 25-17.002 F.A.C. in belief that the current FEECA goals are not the most appropriate "standards" by which a utility's DSM efforts should be evaluated. FPL plans to address its views in regard to the FEECA goals in proceedings for Docket No. 820517-EU.

Summary Of FPL's Demand Side Management Results And Projections

The combined contributions of FPL's demand side management efforts, both as reported in the past and projected into the future, are presented in Table III.H.4. This table incorporates information from Tables III.H.1, 2 and 3, plus the current projection of additional conservation.

Cumulative Summer Demand Reduction Capability
(MW)

	Year	Conservation	On Call	Interruptible* Rates	Total
Actual	1981	19	---	---	19
Actual	1982	69	---	---	69
Actual	1983	149	---	---	149
Actual	1984	246	---	---	246
Actual	1985	355	---	---	355
Actual	1986	456	---	---	456
Actual	1987	550	2	---	552
Actual	1988	599	14	95	708
Actual	1989	624	24	97	745
Projection	1990	642	77	175	894
Projection	1991	660	146	250	1,056
Projection	1992	675	228	335	1,238
Projection	1993	690	310	335	1,335
Projection	1994	705	402	335	1,442
Projection	1995	720	504	335	1,559
Projection	1996	735	610	335	1,680
Projection	1997	750	668	335	1,753
Incremental	1990-1997	126	644	238	1,008

* Interruptible Rates and/or Commercial/Industrial/Load Control Offerings

Table III.H.4

In summary, FPL's DSM efforts in the 1980's have provided FPL with a demand reduction capability of over 700 MW. In the future, FPL projects that continued effort in DSM will contribute an *additional* demand reduction capability of 1,000 MW by 1997, which is accounted for in FPL's generation planning process, as described in *Section IV.E.*

IV. ANALYSIS AND RESULTS

A. Introduction

FPL's final power supply plan was developed using the seven step process described in *Section II* of this report and the input assumptions described in *Section III*. This process:

- Identified a need for over 5,000 MW of capacity and/or load reductions by 1997 to maintain adequate reliability.
- Identified a number of non-construction alternatives to satisfy over 3,000 MW of that need in a cost effective manner (see Table IV.A.1).
- Identified the best series of new unit additions to satisfy the remaining 2,000 MW of capacity need (see Table IV.A.2).
- Tested the final expansion plan to insure that it would remain appropriate under variations in key planning assumptions.

The following subsections detail the analyses and results of each of the major steps in the planning process.

Final Expansion Plan
Options Included Through 1997

	Incremental	Total
Conservation	126 MW	126 MW
Interruptible Load[1]	238 MW	335 MW
Residential Load Control	644 MW	668 MW
Qualifying Facilities	580 MW	1,095 MW
Purchased Power	911 MW	911 MW
New Capacity	2,110 MW	2,110 MW
Total	4,609 MW	5,245 MW

Note:

[1] Includes Commercial/Industrial Load Control

Table IV.A.1

B. Results Of The Reliability Analysis

As described previously, a reliability analysis is performed to determine when new capacity is needed without the construction of new units. Since alternatives to new construction must also be evaluated, system reliability must be examined without these alternatives in place. In other words, the timing of need for new capacity was determined for the FPL most likely load forecast without the alternatives shown in Table IV.B.1.

Power Supply Expansion Plan

Total Installed Cost ($/KW)	Year	Addition	Summer Net
		Lauderdale Repowering Project[1]	
818	1993	Repower Lauderdale No. 4	286 MW
		Repower Lauderdale No. 5	286 MW
		Martin Expansion Project[1]	
821	1994	Martin Combined Cycle No. 3	385 MW
821	1995	Martin Combined Cycle No. 4	385 MW
2,229	1996	Integrated Coal Gasification Combined Cycle (IGCC) Plant consisting of:	
		Martin Combined Cycle No. 5	384 MW
		Martin Combined Cycle No. 6	384 MW
		Total	2,110 MW

Notes:

[1] The Martin Combined Cycle units and the repowered Lauderdale Units are all 400 MW class units. Because FPL's planning is based on its need to meet summer peak demand, all analysis is based on the expected summer net ratings of the proposed units. Actual summer net ratings may vary based on final design and performance testing.

Table IV.A.2

Capacity needs determined in this manner are used to identify all new units which would be required in a "Reference Plan" in which no option but new construction is considered. This establishes a basis for further economic evaluation of the non-construction alternatives.

One alternative to construction which was evaluated during the reliability assessment is the improvement of existing unit availabilities. By improving the performance of existing units, system reliability is enhanced and new capacity requirements may be reduced.

In 1986, FPL developed and started implementing a plan to improve the availability/reliability of its fossil power plants. The plan's objective is to reduce the equivalent forced outage rate (EFOR) of the power plants and to keep the rate low. Keeping EFOR at low levels decreases the requirement for new capacity. The plan consists of a comprehensive methodology which allows the identification of causes of all significant historical failures and implementing solutions to prevent their recurrence, as well as identifying significant potential causes of future failures and developing and implementing solutions to prevent them from occurring. Figure IV.B.1 shows the most recent performance of FPL fossil power plants, as well as the projected targets.

Alternatives Not Considered In Initial Reliability Analysis

- Incremental conservation
- Interruptible load
- Residential load control
- Potential qualifying facility capacity above that already under contract
- New capacity purchases from Southern Company above the 1982 contract

Table IV.B.1

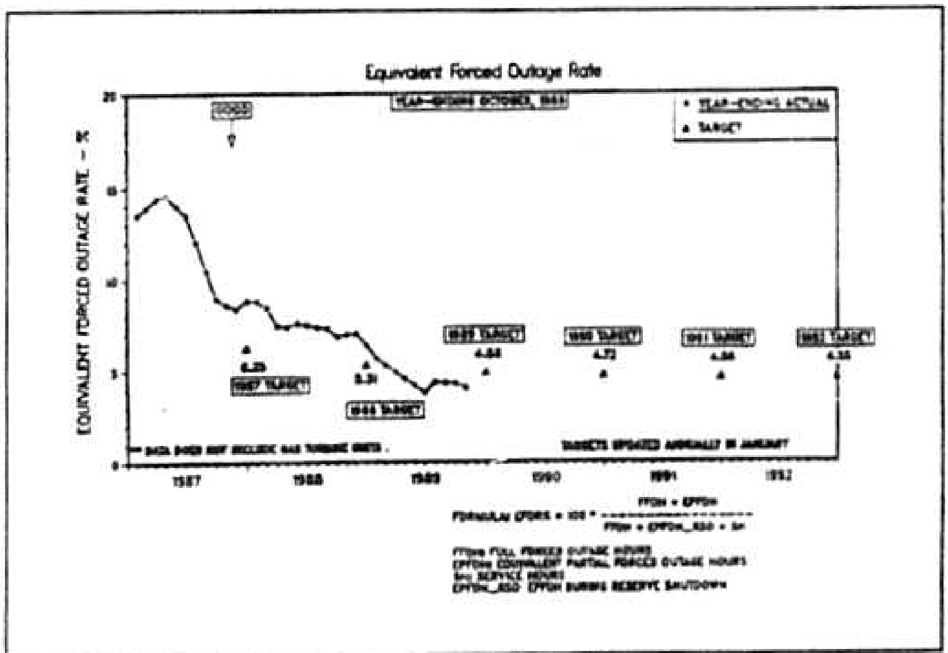


Figure IV.B.1

The FPL system net LOLP was calculated, incorporating the previously described plan. The results, showing that the target of 0.1 days/year is exceeded in 1990, are presented in Figure IV.B 2. The system reserve margin is also calculated and shown in Figure IV.B.3. Based on a minimum reserve margin of 15%, new capacity would be needed in 1993, three years later than shown in the LOLP analysis. Since FPL bases capacity requirements on the more conservative of the two criteria, 1990 is the first year of need in the Reference Plan, based on LOLP requirements. The amount of capacity needed and the required timing of subsequent unit additions are determined by the development of alternative capacity plans, as discussed in *Section IV.D.*

Having identified when new capacity is required, the planning process next moves to the selection of capacity alternatives which are available to meet the system need.

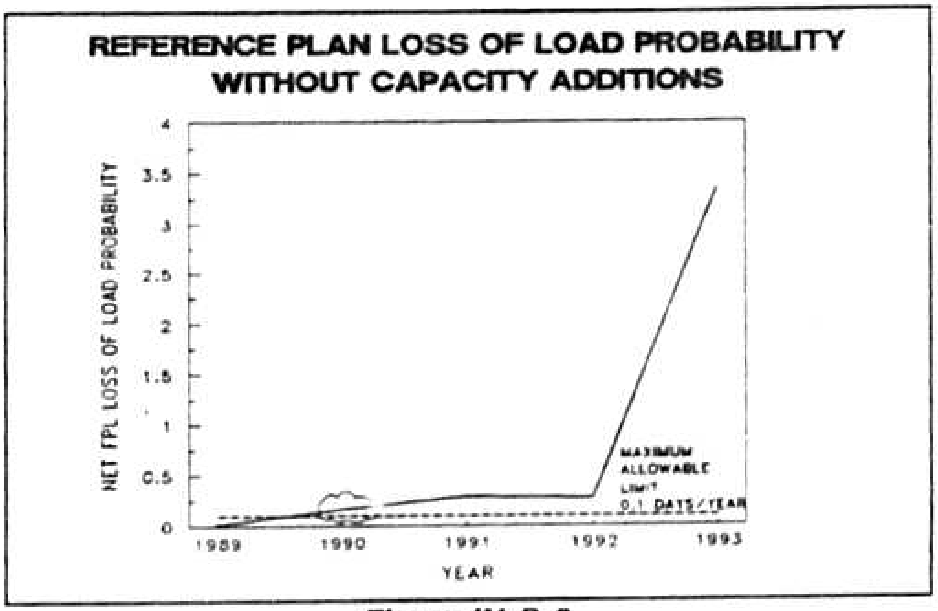


Figure IV.B.2

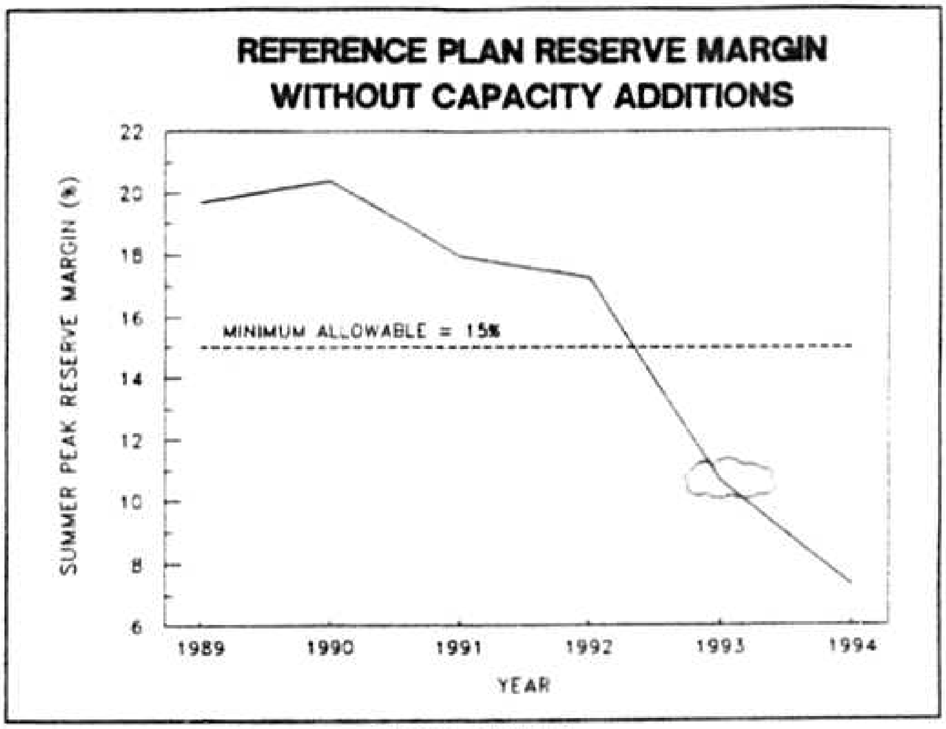


Figure IV.B.3

C. Results Of The Screening Evaluation

There are two steps in the screening evaluation used to identify the capacity options to be studied in detail. First, a "short list" of capacity options is created by eliminating from a comprehensive list those alternatives which do not meet in-service availability, technological maturity or technical feasibility criteria. The initial list is created by reviewing the *EPRI Technical Assessment Guide* (TAG) which lists approximately seventy-five generating technologies and selecting from similar options those which would most likely be considered by FPL (e.g., coal units using lignite or oil fired units using distillate as a primary fuel source are unlikely to be considered by FPL). Technologies with similar characteristics (e.g., various types of IGCC) are also combined and evaluated as one unit. Table IV.C.1 presents the total list of thirty-seven options considered by FPL at this step of the planning process. In deciding which options to retain for economic screening, the following criteria were applied, referring to the headings in Table IV.C.1.

- **In-Service Availability**
  The alternative must be capable of being sited, licensed and constructed to meet a commercial in-service date between January 1, 1992 and January 1, 1996.

- **Technological Maturity**
  The alternative must have been demonstrated on a suitable scale for utility use (100 MW) or have a major sponsor (EPRI, DOE, Utility or Industry) capable of supporting such a demonstration project.

- **Technical Feasibility**
  The alternative must be suitable for use in the FPL service territory, i.e., sufficient resources must be available to develop the option. For example, FPL does not have sufficient water resources to construct a hydro unit within its service territory.

SCREENING EVALUATION OF GENERATION TECHNOLOGIES

TECHNOLOGY	IN-SERVICE AVAILABILITY	TECHNOLOGICAL MATURITY	TECHNICAL FEASIBILITY	RETAIN FOR ECONOMIC SCREENING?
Coal Technologies				
Coal, Steam, Wet Limestone FGD, Sub-critical, 400 MW	1994	Existing	Feasible for FPL	Y
Coal, Steam, Wet Limestone FGD, Sub-critical, 600 MW	1994	Existing	Feasible for FPL	Y
Coal, Steam, Dry FGD, Subcritical	1994	Existing	Limited fuel range	N
Atmospheric Fluidized Bed, Circulating	1994	Demo Projects	Feasible for FPL	Y
Atmospheric Fluidized Bed, Bubbling	1994	Demo Projects	Feasible for FPL	N (Preferred for Retrofit)
Pressurized Fluidized bed, Bubbling, Combined Cycle	1996	No demo to date	Feasible for FPL	N
Coal Gasification, Combined Cycle	1994	Demos of major Technologies	Feasible for FPL	Y
Oil/Gas Technologies				
Oil, Steam, Wet Limestone FGD, 400 MW	1993	Existing	Feasible for FPL	Y
Conventional Combustion Turbine	1992	Existing	Feasible for FPL	Y
Advanced Combustion Turbine	1992	Testing complete 1st delivery made	Feasible for FPL	Y
Intercooled Injected Gas Turbines	1994	No demo to date	Feasible for FPL	N
Conventional Combined Cycle	1992	Existing	Feasible for FPL	Y

Table IV.C.1

SCREENING EVALUATION OF GENERATION TECHNOLOGIES				
TECHNOLOGY	IN-SERVICE AVAILABILITY	TECHNOLOGICAL MATURITY	TECHNICAL FEASIBILITY	RETAIN FOR ECONOMIC SCREENING?
<u>Oil/Gas Technologies</u> (Continued)				
Advanced Combined Cycle	1992	Testing of CT complete; 1st delivery made	Feasible for FPL	Y
Advanced CT Repowering	1992	Testing of CT complete; 1st delivery made	Feasible for FPL	Y
Fuel Cell Phosphoric Acid	1997	No demo to date	Feasible for FPL	N
Fuel Cell Molten Carbonate	1997	No demo to date	Feasible for FPL	N
Fuel Cell - Solid Oxide	1997	No demo to date	Feasible for FPL	N
<u>Nuclear Technologies</u>				
Pressurized Water Reactor	2000	Existing	Feasible for FPL	N
Liquid Metal Fast Breeder Reactor	Beyond 2005	No demo to date	Feasible for FPL	N
Advanced Passive Reactor	Beyond 2005	No demo to date	Feasible for FPL	N
<u>Hydro Technology</u>				
Conventional	1992	Existing	Insufficient resources for FPL	N

Table IV.C.1, Continued

SCREENING EVALUATION OF GENERATION TECHNOLOGIES

TECHNOLOGY	IN-SERVICE AVAILABILITY	TECHNOLOGICAL MATURITY	TECHNICAL FEASIBILITY	RETAIN FOR ECONOMIC SCREENING?
Renewable Technologies				
Geothermal	1992	Existing	Insufficient resource for FPL	N
Wind Turbines	1992	Existing	Insufficient resource for FPL	N
Hybrid Solar Central Receiver	1997	Existing	Concern over production capabilities	N
Solar Photovoltaic	1997	Existing	Concern over production capabilities	N
Ocean Thermal	1997	No major sponsor	Feasible for FPL	N
Ocean Current	1997	No major sponsor	Feasible for FPL	N
Ocean Wave	1997	No major sponsor	Insufficient resource for FPL	N
Ocean Tidal	1997	Existing	Insufficient resource for FPL	N
Wood-Fired Steam	1992	Existing	Insufficient resource for FPL	N
Municipal Refuse Steam	1992	Existing	Pursued by others	N
Storage Technology[1]				
Lead Acid Battery	1992	Existing, but may may have supply limitations	Unknown	N
Advanced Battery	1992	Existing, but may may have supply limitations	Unknown	N
Pumped Hydro Storage	1992	Existing	Inappropriate geology for FPL	N

[1] Detailed examination of storage technologies is to be done following the results of a feasibility study which will be conducted by FPL in 1990.

Table IV.C.1, Continued

SCREENING EVALUATION OF GENERATION TECHNOLOGIES				
TECHNOLOGY	IN-SERVICE AVAILABILITY	TECHNOLOGICAL MATURITY	TECHNICAL FEASIBILITY	RETAIN FOR ECONOMIC SCREENING?
Storage Technology (Continued)				
Compressed Air Energy Storage - Rock, Salt, Aquifer	1992	Existing	Inappropriate geology for FPL	N
Compressed Air Energy Storage Vessel	1992	Existing	Unknown	N
Superconducting Magnetic Energy Storage	1997-1999	No major sponsor	Unknown	N

Table IV.C.1, Continued

Based on the above criteria, the following "short list" of options to be evaluated in economic screening was developed.

- Coal, steam, wet limestone FGD, subcritical, 400 MW
- Coal, steam, wet limestone FGD, subcritical, 600 MW
- Atmospheric fluidized bed circulating
- Coal gasification combined cycle
- Oil, steam, wet limestone FGD, 400 MW
- Conventional combustion turbine
- Advanced combustion turbine
- Conventional combined cycle
- Advanced combined cycle
- Advanced CT repowering

The second step in the screening evaluation is the development of screening curves that show levelized capital and operating costs for each option over a range of capacity factors up to projected unit availability. These curves aid in further paring of the list of alternatives to a manageable few. The relevant costs used in the development of the screening curves are shown in Table IV.C.2. Options are initially grouped for comparison by fuel type and expected operating mode (e.g., combustion turbines are grouped together, as are combined cycles and repowering, etc.). Capital, O&M and fuel costs are levelized over a thirty year period for comparison. Fuel levelization is accomplished by calculating a levelized fuel charge which represents the average cost of fuel over a thirty year period. This enables an accurate comparison of relative costs over the life of the units.

Figure IV.C.1 shows a comparison of the coal technologies remaining on the list. The curve shows that the 600 MW pulverized coal (PC) unit and the 800 MW coal gasification combined cycle (IGCC) are competitive at higher capacity factors. The atmospheric fluidized bed (AFB) unit and 400 MW pulverized coal unit show higher costs throughout the range of capacity factors. Based on these curves, the IGCC and 600 MW PC units are retained for the detailed economic analysis.

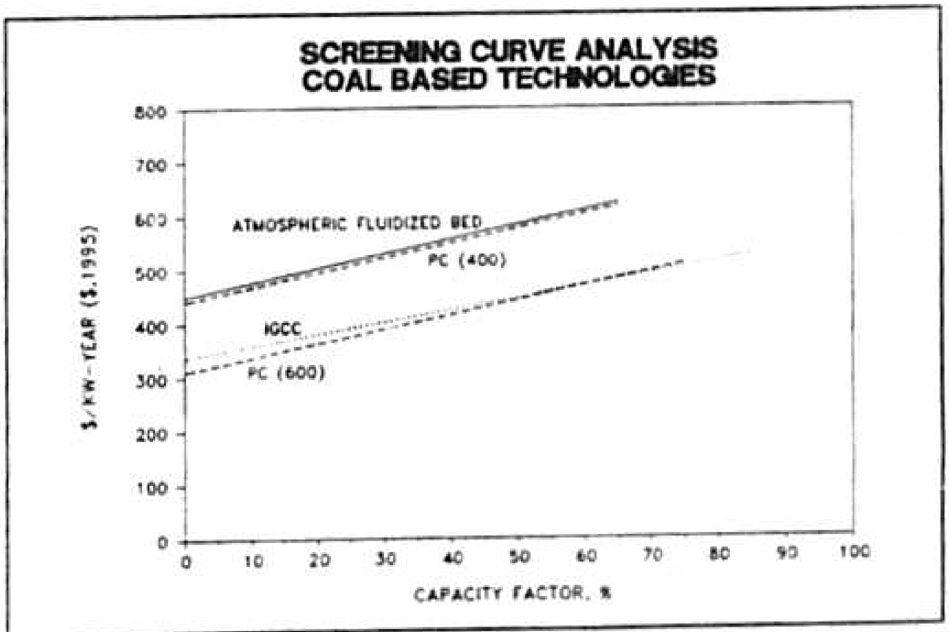


Figure IV.C.1

Cost Parameters Used In Screening Curves[f]

Unit Type	Pulverized[f] Coal	Pulverized[f] Coal	Supercritical[g] Pulverized Coal	Atmospheric Fluidized Bed	Coal[f] Gasification Combined Cycle (IGCC)	Oil[g]	Conventional Combustion Turbine	Advanced Combustion Turbine	Conventional Combined Cycle	Advanced Combined Cycle	Combustion[g] Turbine Repowering
Nominal Size	400 MW	600 MW	750 MW	400 MW	800 MW	400 MW	75 MW	140 MW	220 MW	300 MW	286 MW[a]
Capital Cost ($ 1995/KW)[b]	2,018	1,530	1,432 1,383	2,098	1,601	1,432	375	575	622	695	825
Heat Rate BTU/KWH[c]	9,792	9,739	9,449	9,878	8,781	9,400	13,800	11,416	8,394	7,620	7,578
O&M[d] Fixed (1995 $/KW-Yr.)	73.52	32.18	32.62	67.69	46.78	23.47	0.68	11.21	10.25	18.69	17.35
Variable (1995 $/MWH)	3.72	3.19	3.42	3.28	1.06	0.98	6.15	0.58	2.60	0.76	1.19
Primary Fuel[e]	High Sulfur Coal	High Sulfur Coal	High Sulfur Coal	High Sulfur Coal	High Sulfur Coal	0.7% S Residual Oil	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas

Notes:

[a] Repowering size is net increase in MW at Lauderdale Unit 4 or 5.

[b] Capital costs are in 1995 dollars, escalated from 1989 using PPI, Capital Goods. AFUDC is not included.

[c] Heat Rate is at 100% load.

[d] O&M costs are in 1995 dollars, escalated from 1989 using CPI.

[e] Fuel price information is presented in Appendix D.

[f] All data developed by FPL Project Management Department except IGCC, which was developed by Fluor, Inc. for the EPRI/FPL Site Specific IGCC Study and the Conventional Combustion Turbine and Conventional Combined Cycle, which are from the EPRI Technical Assessment Guide. The 600 MW Pulverized Coal numbers are based on the FPL SJRPP units.

[g] The costs reflect the average of two units.

Table IV.C.2

Figure IV.C.2 compares the oil fired steam unit, advanced combustion turbine (CT) repowering, conventional combined cycle (CC) and advanced combined cycle (CC) options. The curve shows the advanced CC to have an economic advantage over all but very low capacity factors (i.e., less than 20%). Because combined cycle units for FPL's system are expected to operate at higher capacity factors, the conventional CC option was eliminated from further consideration.

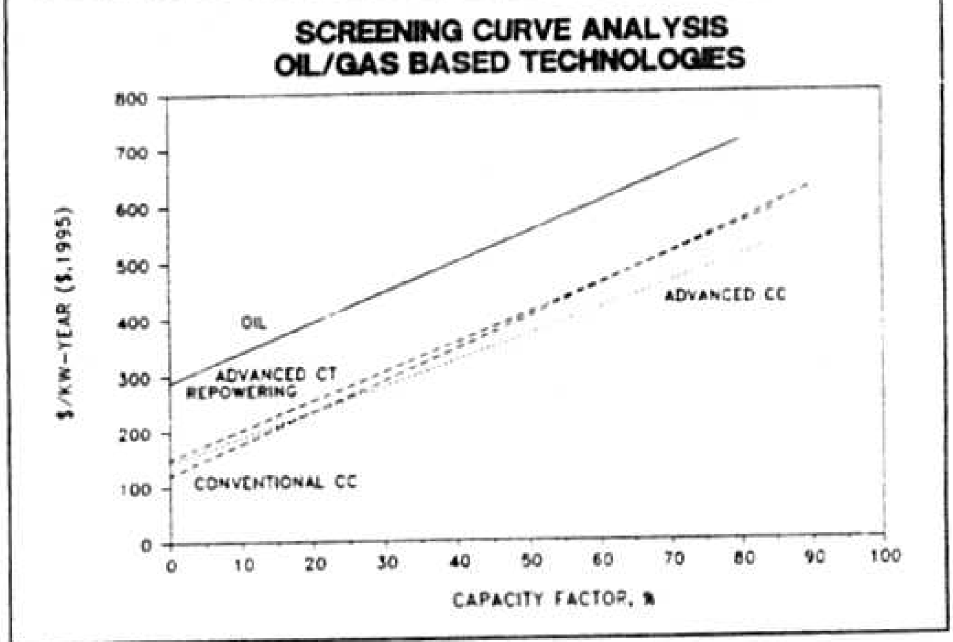


Figure IV.C.2

The advanced CT repowering option appears to be higher cost than the advanced CC over the entire range of capacity factors. However, the screening curve methodology does not reflect the incremental improvement in the efficiency of existing capacity that is obtained in the repowering. This can be reflected in the detailed economic analysis. Therefore, both the advanced combined cycle and the advanced CT repowering options are kept for detailed economic analysis.

Figure IV.C.3 compares the remaining options and shows that the advanced combustion turbine is more economic than the conventional combustion turbine over all but the lowest end of the capacity factor range. Although combustion turbines would normally be expected to run at a low capacity factor, compatibility with future combined cycle operation and coal gasification was considered to be an overall strategic goal of the planning process. The advanced CT, with its higher operating efficiency, is more compatible with this goal. The advanced CT was, therefore, retained for detailed economic analysis.

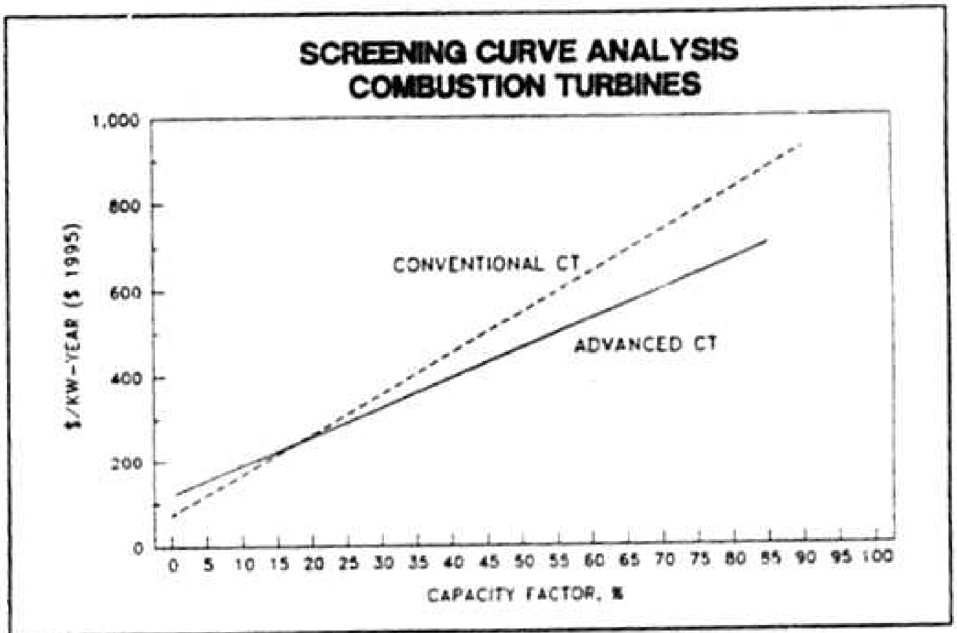


Figure IV.C.3

The three figures presented above show groupings of alternatives with expected similar operating characteristics. Figure IV.C.4 shows a comparison of alternatives that were retained for detailed economic analysis. Note that many of the curves cross one another, preventing a judgment on which alternative is most economic, since each option may be expected to operate at a different capacity factor based on its variable operating cost.

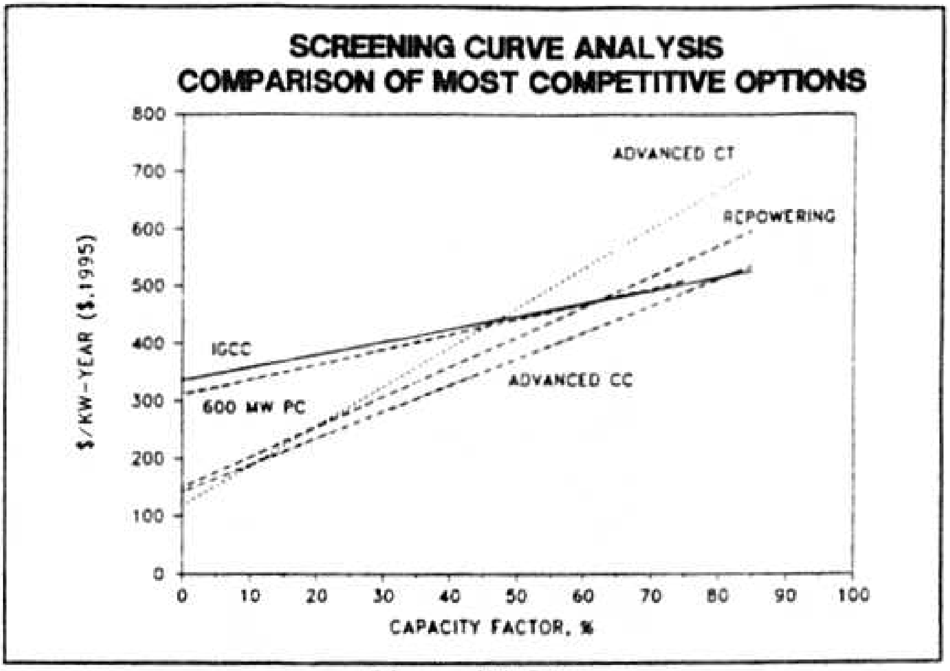


Figure IV.C.4

D. Results Of The Economic Analysis Of The Reference Plan

The Reference Plan is a generation expansion plan developed without any of the options listed in Table IV.D.1. Each of these non-construction alternatives will be added to the Reference Plan in a later step in the analysis to the extent they are available and cost effective. The Reference Plan serves as a basis for economic evaluation of these alternatives.

Alternatives Not Considered In Development Of The Reference Plan

- Incremental conservation
- Interruptible load
- Residential load control
- Potential qualifying facility capacity above that already under contract
- New capacity purchases from Southern Company above the 1982 contract

Table IV.D.1

The first step in creating the Reference Plan is to develop a reasonable number of alternative plans that consist of various combinations of the supply side options (other than repowering) remaining after the screening evaluation. A list of the alternative plans is presented in Table IV.D.2. The rationale for developing these alternative plans is shown on the following page.

Alternative Expansion Plans - Reference Case
Unit Additions Through The Year 2000

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total MW
R.1	1-CC	3-CC	1-CC 1-IGCC	1-IGCC	2-IGCC	1-IGCC	------	1-IGCC	1-IGCC	7,301
R.2	1-CC	3-CC	1-CC 1-IGCC	1-IGCC	2-CC 1-IGCC	1-IGCC	------	1-IGCC	1-IGCC	7,303
R.3	1-CC	3-CC	1-CC	2-IGCC	2-CC 1-PC	1-PC	1-PC	------	2-PC	7,351
R.4	1-CC	2-CC 1-IGCC	1-IGCC	1-IGCC	2-IGCC	1-IGCC	------	1-IGCC	1-IGCC	7,299
R.5	1-CC	2-CC 1-IGCC	1-IGCC	2-CC	2-IGCC	1-IGCC	------	1-IGCC	1-IGCC	7,301
R.6	1-PC	2-PC	1-PC	3-PC	2-PC	1-PC	1-PC	1-PC	1-PC	8,112
R.7	3-CT	3-CC	1-CC 1-IGCC	1-IGCC	2-IGCC	1-IGCC	------	1-IGCC	1-IGCC	7,291
R.8	1-PC	1-PC 1-CC	1-IGCC	2-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC	7,009
R.9	3-CT	2-PC	1-IGCC	2-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC	6,999
R.10	3-CT	2-PC	1-IGCC	1-IGCC 1-CC	3-CC 1-IGCC	------	1-IGCC	------	1-IGCC	7,003
R.11	1-CC	3-CC	1-CC 1-PC	1-PC 1-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC	7,013
R.12	1-CC	3-CC	1-CC	3-CC	4-CC	1-CC	1-CC	1-CC	2-CC	6,545
R.13	1-IGCC	1-IGCC	1-IGCC	2-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC	6,912
*R.14	1-PC	2-PC	1-PC	2-PC	3-PC	1-PC	1-PC	------	1-PC	9,000
R.15	1-CC	3-CC	1-CC 1-PC	1-PC 1-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC	7,013

Note:

CT: 125 MW Combustion Turbine
CC: 385 MW Combined Cycle
IGCC: 768 MW Coal Gasification Combined Cycle Plant
PC: 624 MW Pulverized Coal Unit
*PC: 750 MW Pulverized Coal Unit

Table IV.D.2

- Only a limited number of natural gas fired units can be supported due to limited fuel supply. One 385 MW Combined Cycle unit would use approximately 70 MCF per day of natural gas at full capability during the summer. The average firm daily supply of natural gas to FPL is 327 MCF per day (see *Appendix D*), with additional volumes available during the summer months. This would limit the number of economic combined cycle units in any alternative plan to five or six. Three cases (R.2, R.3 and R.12) were developed which exceed this number of combined cycle units in order to verify the effect of the gas limits.

- The pulverized coal units have high costs associated with the initial unit and lower costs with the second unit. Therefore, these units were always added in pairs to take advantage of the economy of the second unit.

- Repowering was not considered in the development of the Reference Plan in order to simplify the analysis. This is discussed further in *Section IV.F.*

- The scheduling of units was generally developed to meet the system reliability criterion of 0.1 days per year LOLP. Case R.1 meets the LOLP criterion in all years. The other alternative plans have unit schedules which are similar, but do not in all cases meet LOLP in every year. For example, since unit capacities and availabilities differ, (e.g., the pulverized coal unit is 624 MW versus 768 MW for the IGCC), Case R.6 does not quite meet 0.1 days per year in 1996.

- Case R.6 was developed to show the impact that lower availability (75.6% for the PC unit versus 87% for the CC and IGCC) has on capacity requirements over the period 1992 through 2000. A plan consisting solely of lower availability PC units requires significant additional capacity compared to a plan consisting of CCs and IGCCs.

The second step in creating the Reference Plan is to perform an economic comparison of the alternative generating plans. The results of the economic analyses are presented in graphic form in Figures IV.D.1 to IV.D.3. The present value of revenue requirements (PVRR) savings in 1989 dollars (millions) are plotted against Case R.1. Clearly, different alternative plans are most economic at different times. Table IV.D.3 shows the relative economic rankings of the different plans at twenty, twenty-five and thirty years into the future.

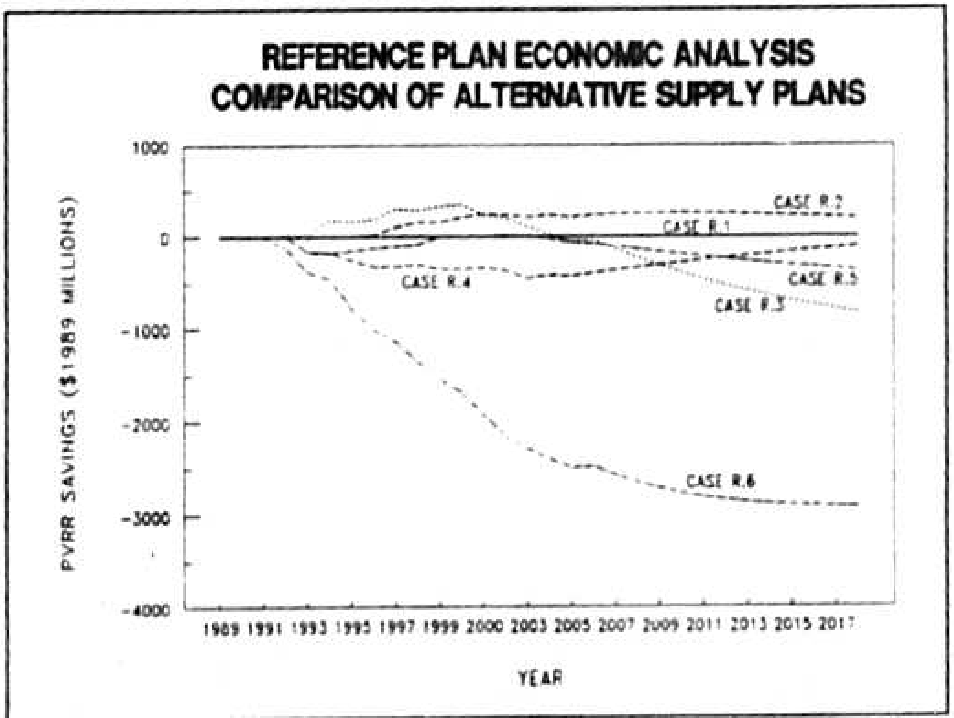


Figure IV.D.1

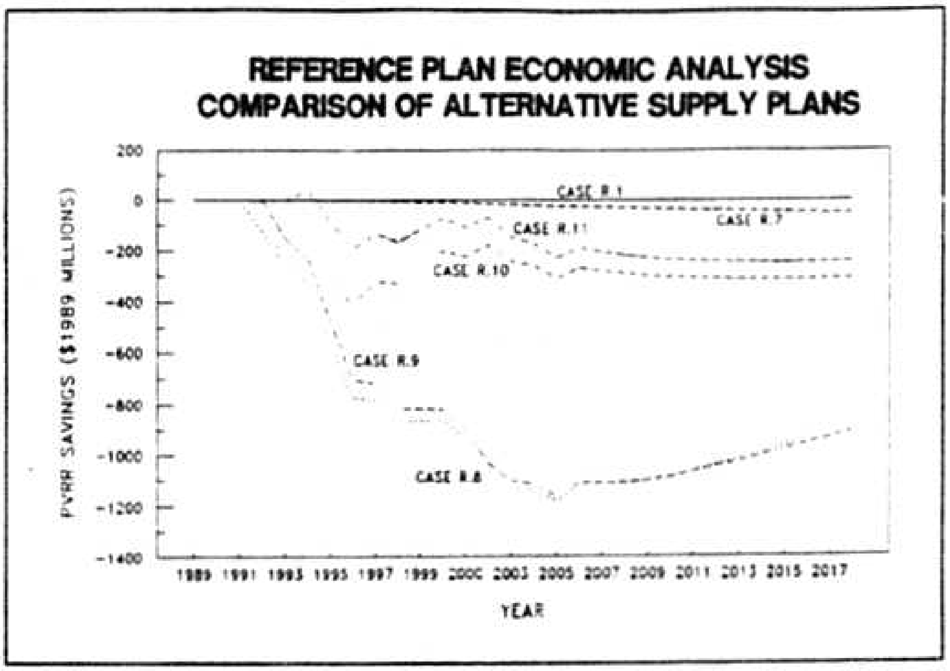


Figure IV.D.2

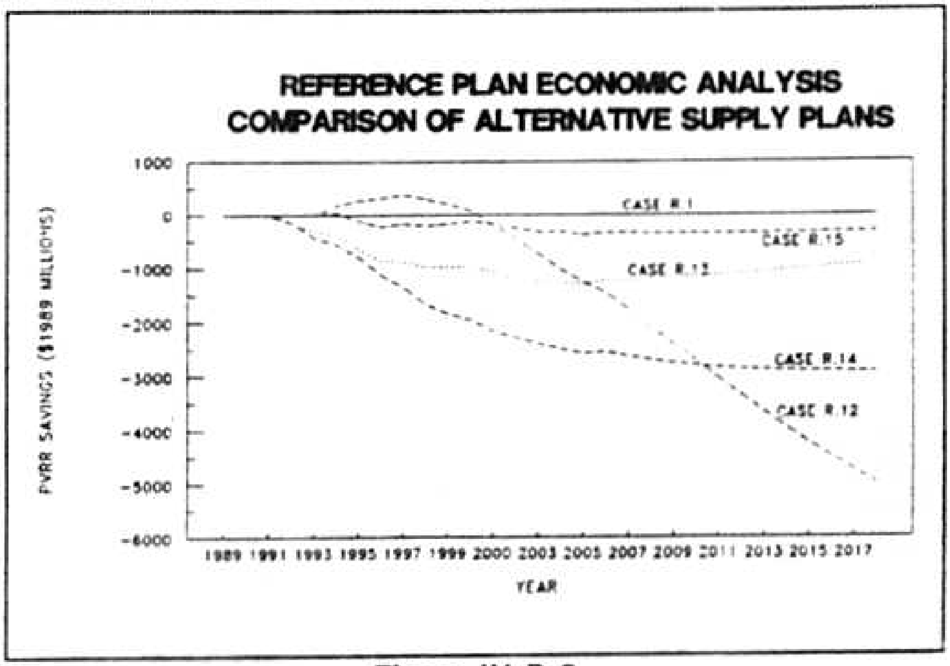


Figure IV.D.3

Determination Of Need
Reference Case Optimization

	Generating Units Added 1992-2000				PVRR In Millions					
					1989-2008		1989-2013		1989-2018	
Case	IGCC	PC	CC	CT	PVRR	Rank	PVRR	Rank	PVRR	Rank
R.2	6		7		29,948	1	34,933	1	38,351	1
R.1	7		5		30,201	2	35,176	2	38,550	2
R.4	8		3		30,534	8	35,383	3	38,662	3
R.11	5	2	5		30,417	5	35,420	4	38,792	4
R.5	7		5		30,336	3	35,440	5	38,[illegible]19	7
R.10	5	2	4	3	30,489	7	35,486	6	38,859	5
R.7	7		4	3	30,380	4	35,501	7	38,992	8
R.15	5	2	5		30,544	9	35,517	8	38,868	6
R.3	2	5	7		30,436	6	35,774	9	39,392	9
R.8	7	2	1		31,309	11	36,184	10	39,431	10
R.9	7	2		3	31,304	10	36,196	11	39,453	12
R.13	9				31,398	12	36,232	12	39,440	11
R.6		13			32,855	14	38,040	13	41,472	14
R.14		12			32,896	15	38,049	14	[illegible]1,462	13
R.12			17		32,290	13	38,835	15	43,551	15

Table IV.D.3

Based on relative economics and strategic considerations, Plan R.1 was selected to be the Reference Plan and is summarized in Table IV.D.4.

Summary Of Plan R.1
Reference Plan

1992	1-385 MW Combined Cycle
1993	3-385 MW Combined Cycle
1994	1-385 MW Combined Cycle 1-768 MW IGCC
1995	1-768 MW IGCC
1996	2-768 MW IGCC
1997	1-768 MW IGCC
1998	No Additions
1999	1-768 MW IGCC
2000	No Additions

Table IV.D.4

With the exception of Plan R.2, Plan R.1 ranked as the most economic over all time horizons. Plan R.2's only difference from the case selected is that it substituted two combined cycle units for one of the 1996 IGCC units in Plan R.1. A plan such as R.2, which contains additional combined cycle units, is reliant on there being an adequate supply of non-firm gas available. In addition, the ability of the gas pipeline to supply sufficient quantities of gas to sites south of Ft. Pierce is limited.

This would require siting of the two additional combined cycle units in Case R.2 north of Martin, which conflicts with the need to site new generation near FPL load centers. While Case R.2 appears to be economically advantageous, it cannot be realistically implemented without enhancements to the gas supply or electrical transmission system.

E. Results Of Economic Evaluation Of Alternatives To New Construction

The Reference Plan establishes a schedule of new generating units which would be required if no other alternatives were available. There are, however, alternatives to new construction in the form of both demand side and supply side alternatives. These include conservation, load management, interruptible load, QFs and purchased power from other utility sources.

The order in which these alternatives are added into the Reference Plan must be considered when cost effectiveness versus new construction is determined. The economic benefits of any alternative, derived primarily from the avoidance and/or deferral of specific generating units, are compared to the costs associated with that alternative. Obviously, the calculation of benefits will be dependent on the type and timing of the unit against which an alternative is measured. Alternatives which are implemented first would produce greater benefits by virtue of eliminating the first units shown in the Reference Plan. Deferral of later units produces less benefit and so on. How, then, should the alternatives be evaluated? One approach would be to compare the cost effectiveness of all alternatives against the first generating unit, then implement the one which shows the greatest benefit/cost ratio. However, any methodology based solely on cost does not take into account important strategic factors, such as customer choice and conservation of natural resources.

Given the strategic factors previously discussed in *Section II.H*, it would seem appropriate to differentiate between demand side and supply side alternatives to new plant construction, taking demand side options first in the analysis. Why take demand side programs first? In theory, customers could choose to participate in demand side programs in such numbers that future capacity additions would not be needed. In practice, participation in demand side programs reduces the magnitude and slows the timing of needed new capacity. Thus, this "customer choice" impact should be accounted for first to the extent that programs can be cost effectively implemented. Other considerations favoring Demand Side Programs appear in Table IV.E.1.

Other Considerations Of
<u>Demand Side Programs</u>

- "Customer choice" is fully addressed, since customers may choose their desired level of reliability and corresponding price or choose an appropriate comfort level and corresponding price.
- Program implementation rates can be increased or decreased to more closely follow load growth and economic considerations.
- Demand side programs can, in some cases, be implemented with shorter lead times.

Table IV.E.1

In prioritizing within the demand side programs, similar consideration of these strategic factors results in an implementation order of conservation, followed by interruptible rates, then load control. Conservation is considered first, emphasizing its role in offering a broad variety of choices to virtually all FPL customers. Interruptible Load and Commercial/Industrial Load Control follow in priority because they can be rapidly increased to meet future needs. Residential load control is considered as the last demand side program due to its relatively slower implementation rate.

In considering supply side alternatives to new construction, prioritization is determined more by regulatory requirements than by strategic considerations. Since utility purchases from QFs are mandated by the 1978 PURPA legislation and the FPSC Rule 25-17.080 - 25-17.091, they are added first to the plan at full avoided cost. Any remaining purchased power options would then be evaluated. While purchases from utility sources may be more cost effective than purchases from QFs, thus reducing the full avoided cost, no attempt was made to evaluate this impact in this study.

Based on the above considerations, the alternatives to new power plant construction were added to the Reference Plan in the following order:

- Conservation
- Interruptible Load
- Residential Load Control
- Qualifying Facilities
- Purchased Power (1988 Southern UPS Contract)

As each alternative was added to the Reference Plan, a new expansion plan was identified and the benefits of the alternative were calculated for comparison to costs. A summary of the intermediate expansion plans is shown on the following page in Table IV.E.2.

The incremental savings provided by each alternative are presented in Figures IV.E.1 through IV.E.3. Total savings of the final resultant plan versus the Reference Plan are shown in Figure IV.E.4.

In each case, the MW levels of the alternatives were fixed at currently projected levels. Implementation rates and costs for conservation were as reported in Docket No. 880002-EG in November, 1988, with the inclusion of revenues losses. For interruptible

Intermediate Expansion Plans For Demand Side Options

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000
Reference Plan	1-CC	3-CC	1-CC 1-IGCC	1-IGCC	2-IGCC	1-IGCC	------	1-IGCC	1-IGCC
Add Conservation	1-CC	2-CC	2-CC	2-IGCC	2-IGCC	------	1-IGCC	------	1-IGCC
Add Interruptible Rates	----	2-CC	2-CC	1-CC 1-IGCC	2-IGCC	1-IGCC	------	1-IGCC	------
Add Residential Load Control	----	1-CC	2-CC	2-CC	2-IGCC	1-IGCC	------	1-IGCC	------
Add Qualifying Facilities	----	1-CC	2-CC	1-CC	1-CC 1-IGCC	1-IGCC	------	1-IGCC	1-IGCC
Add Southern Purchases (1988 Southern UPS Contract)	----	1-CC	1-CC	1-CC	2-CC	1-IGCC	------	1-IGCC	1-IGCC

(Year spans columns 1992–2000.)

Note:

CC: 385 MW Combined Cycle Unit
IGCC: 768 MW Coal Gasification Combined Cycle Unit

Table IV.E.2

rates and residential load control, the sign up rates and costs were based on the targets established in the testimony of S.S. Waters in Docket No. 870197-EI, the Non-Firm Service Rule, and were updated slightly for purposes of this study. These targets were identified in that filing as the cost effective maximum levels of these programs.

The level of qualifying facilities added reflects FPL's most likely forecast of future supply. The cost associated with these QFs was assumed to be the cost of the avoided capacity, modified to include an 80% risk factor. The purchase from Southern Company of 911 MW reflects the terms of the 1988 Unit Power Sales agreement. Other power purchase offers have been evaluated by FPL over the past several years and been found either not to be cost effective or to present unacceptable levels of risk. These offers involved both non-utility and out of state utility sources and have totalled over 3,500 MW of capacity in years 1991 through 2000. FPL has also explored the availability of generating capacity from other Florida utilities in the desired time frame, but capacity is not expected to be available for purchase. As evidenced by the individual utility filings in the 1989 Annual Planning Hearings, most Florida utilities show a need for capacity on their own systems by the mid-1990's. The consistency of FPL's plan with the needs of peninsular Florida is further discussed in *Section IV.I.*

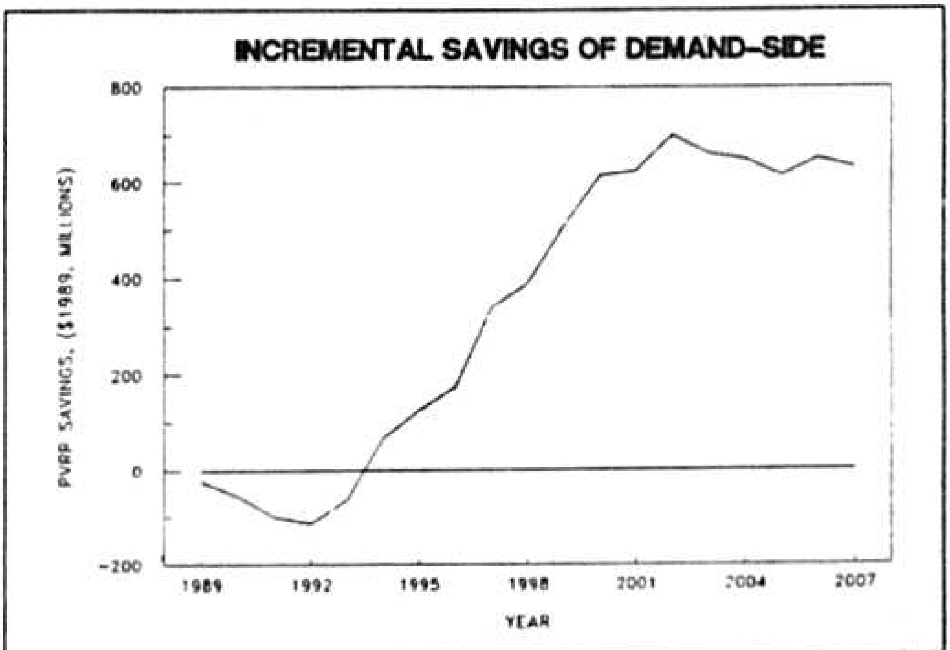


Figure IV.E.1

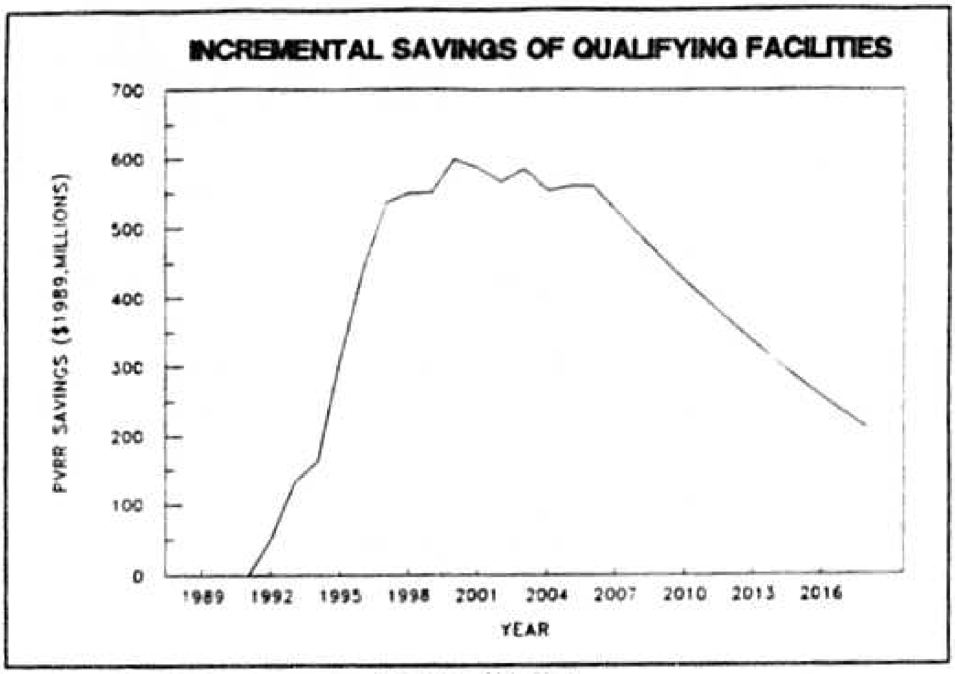


Figure IV.E.2

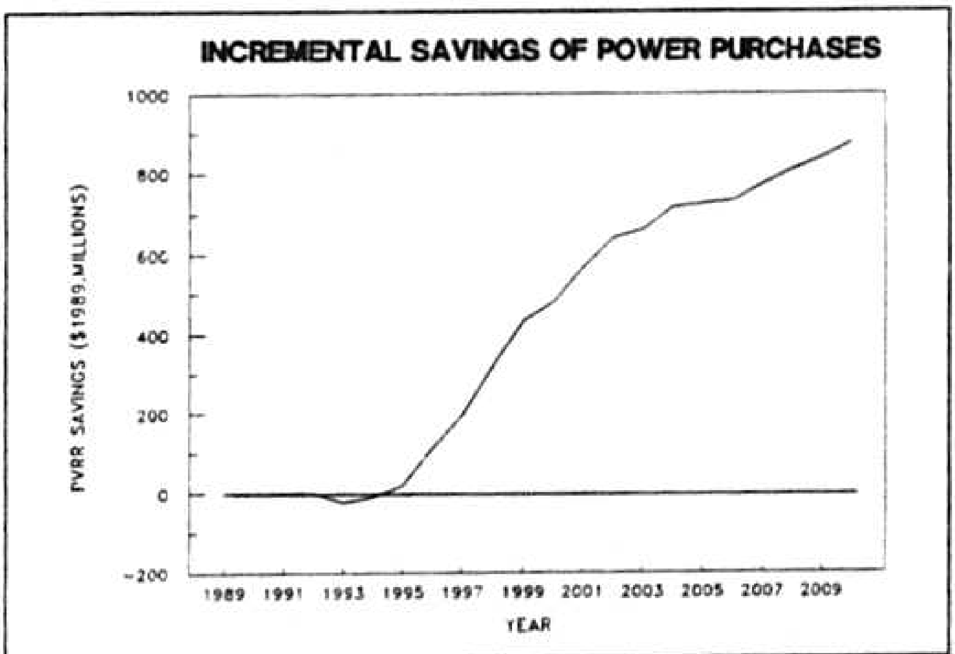


Figure IV.E.3

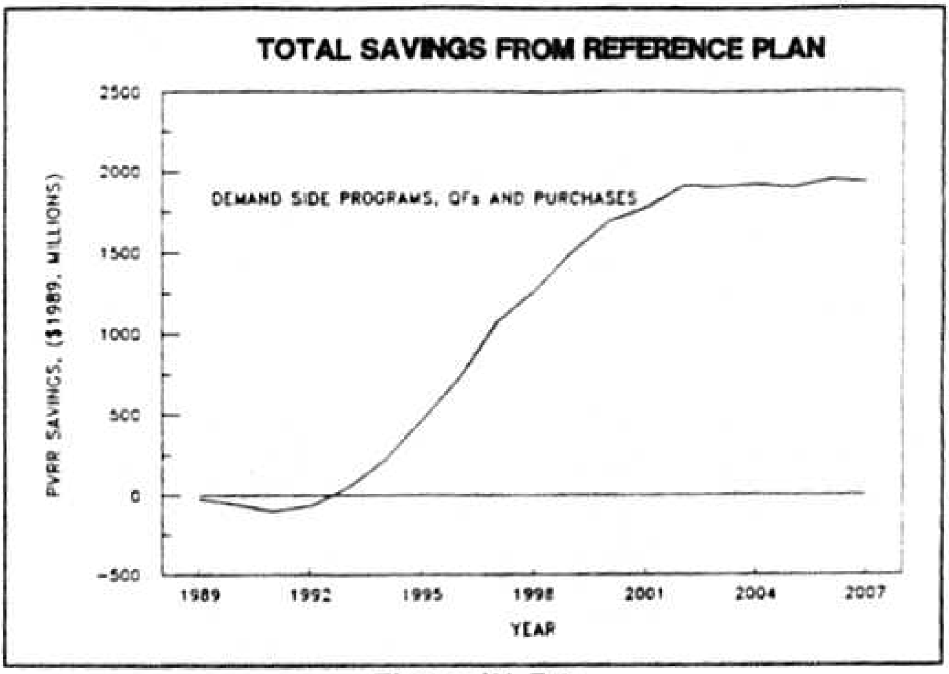


Figure IV.E.4

F. Addition Of Repowering To The Plan

Having begun with an expansion plan based entirely on the construction of new units and then having displaced some of these units with alternatives to new construction, the next step in the development of the final plan would normally be the retesting of plan economics versus a number of competing plans consisting of different combinations of units. However, before proceeding to this step, one additional generating option, which combines new construction with conversion of existing capacity, was examined. Known as repowering, this option improves the efficiency of existing capacity and adds new capacity to the system by converting an existing steam-fired unit to combined cycle operation through the addition of combustion turbines and heat recovery steam generators. A schematic diagram of repowering is shown in *Section V.A.*

Repowering had been excluded in development of the Reference Plan in order to simplify the analysis of non-generating alternatives. That simplification was appropriate for two reasons:

- First, the life cycle cost of repowering and new combined cycle units are comparable, due to similarities in capital cost and operating costs. Thus, the simplification has little impact on the overall analysis.

- Second, to the extent that repowering has an economic advantage over new combined cycle units and presents strategic benefits, repowering should be included in the final expansion plan. If repowering were included in the Reference Plan as the first unit to be "avoided" by non-generating alternatives, it would only have to be reintroduced into the plan at a later step in order to preserve the optimum stream of unit additions. So long as repowering is preferred over new combined cycle units, delaying its introduction into the analysis simplifies the study with no impact on the final results.

Repowering is more economic than a new combined cycle unit as the first unit addition on FPL's system. Figure IV.F.1 shows the net savings provided by replacing the 1993 Combined Cycle Unit in the Reference Plan with the repowering of Lauderdale Unit Nos. 4 and 5. The analysis shows a net present value of approximatley $100 million through the year 2018. The addition of repowering, combined with the alternatives to new construction discussed in the previous section, results in a total savings, in present value terms, of over $2 billion compared to the Reference Plan. Total savings versus the Reference Plan are shown in Figure IV.F.2.

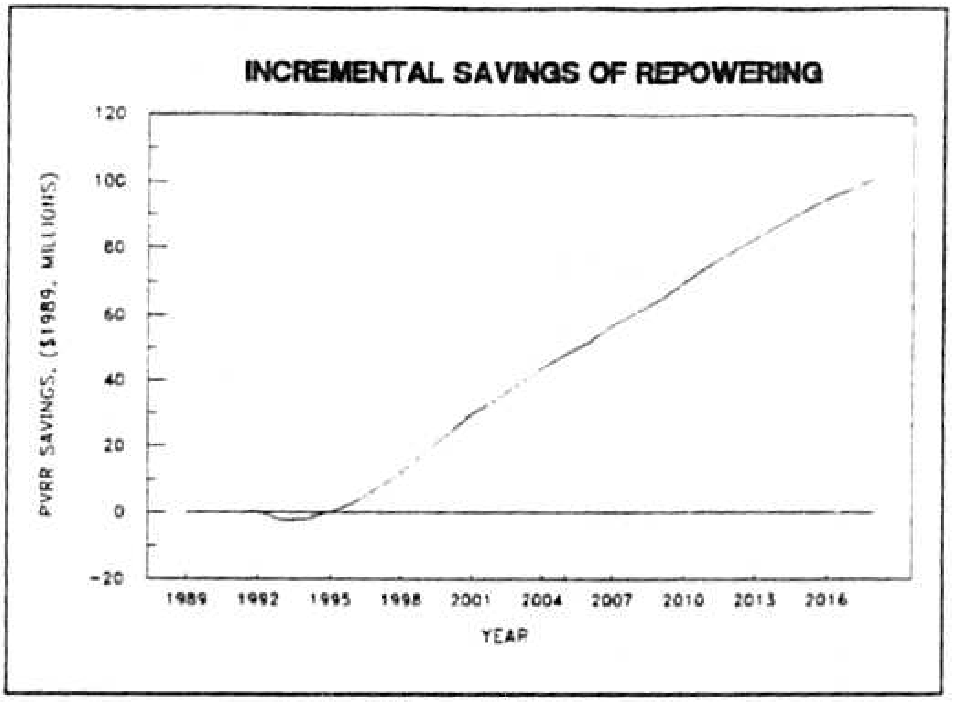


Figure IV.F.1

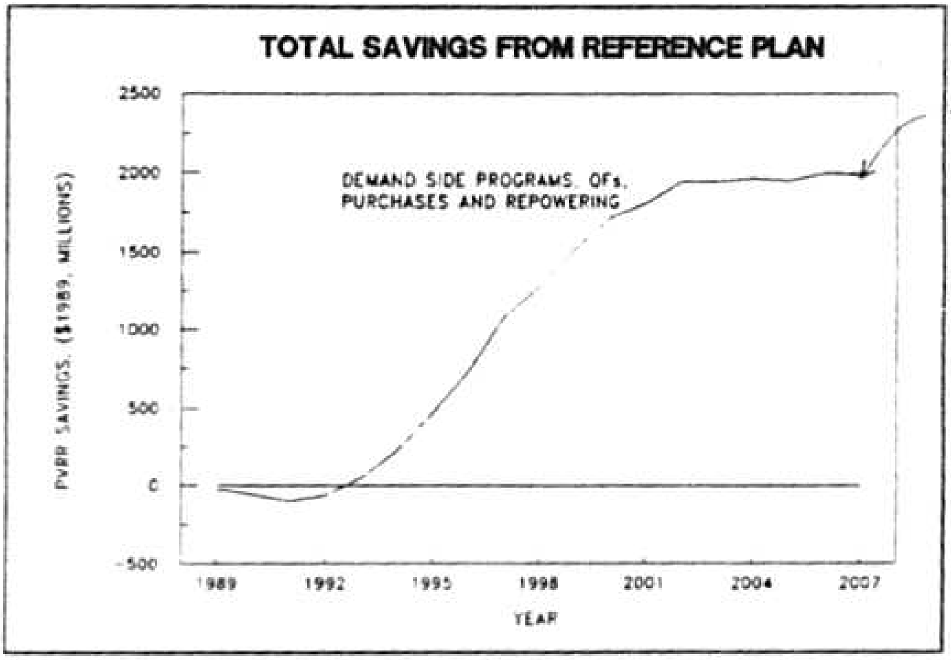


Figure IV.F.2

It should be noted that repowering has both unique benefits and unique risks that must be considered in selecting repowering as a generating option.

The strategic benefits provided by repowering include:

- Existing sites and associated infrastructures can be utilized instead of developing new sites.

- New generation can be located near the FPL load center without the acquisition of new sites.

- New generation can more easily be integrated into the existing transmission grid.

- In addition to providing new capacity, the efficiency of existing generation is increased.

The risks associated with repowering include:

- Repowering represents a slightly greater technical risk than building a new unit, since the output of the combustion turbine/heat recovery steam generator set (CT/HRSG) must be matched to drive the existing steam turbine, rather than designing the entire system to match. This may result in more difficult operational requirements.

- Existing capacity must be temporarily removed from service while the repowering is in progress. This capacity may be lost for an extended period if any unexpected problems arise.

- The use of existing, aging equipment may result in impaired performance in the short term.

The reasons for selecting the Lauderdale units for repowering are discussed in *Section V.B*. While FPL believes that the strategic benefits provided by the Lauderdale repowering more than offset the risks associated with the project, additional repowering is not being pursued until needed experience has been gained at Lauderdale. FPL may pursue additional repowering if this experience is favorable and the economics of specific projects appear attractive.

G. Results Of Economic Analysis Of The Base Case

The addition of non-construction alternatives and the Lauderdale repowering to the Reference Plan results in the new capacity schedule shown in Table IV.G.1. This is referred to as the Base Plan.

Summary Of Plan Results
Base Plan

1993	2-Repowered Units (Net increase of 286 MW each)
1994	1-385 MW Combined Cycle
1995	1-385 MW Combined Cycle
1996	1-768 MW IGCC

Table IV.G.1

The Base Plan was then re-tested against alternative expansion plans under the most likely set of assumptions. This analysis was conducted to ensure that the Base Plan continued to be the best alternative to meet economic and strategic objectives. Alternative expansion plans were selected in a manner similar to that used in developing alternatives to the Reference Plan. Table IV.G.2 lists the alternative expansion plans evaluated under the most likely set of assumptions. A comparison of the present value of revenue requirements (PVRR) of the alternative cases, compared to the PVRR of the Base Plan, is shown in Figures IV.G.1 to IV.G.4.

Alternative Expansion Plans Evaluated Under Most Likely Assumptions

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total MW
Base	----	2-REP	1-CC	1-CC	1-IGCC	------	1-IGCC	------	1-IGCC	3,646
B.2	----	2-REP	1-CC	1-CC	2-CC	------	1-IGCC	------	1-IGCC	3,648
B.3	----	2-REP	1-CC	1-CC	2-CC	------	1-PC	1-PC	1-PC	3,984
B.4	----	2-REP	1-IGCC	------	1-IGCC	------	1-IGCC	------	1-IGCC	3,644
B.5	----	2-REP	1-IGCC	------	2-CC	------	1-IGCC	------	1-IGCC	3,646
B.6	----	2-REP	1-CC	1-CC	1-IGCC	------	1-PC	1-PC	1-PC	3,982
B.7	----	2-REP	2-CT	1-CC 1-CT	1-IGCC	1-IGCC	------	------	1-IGCC	3,636
B.8	----	2-REP	1-CC	1-PC	1-PC	1-IGCC	------	1-IGCC	1-IGCC	4,509
B.9	----	1-CC	1-CC	1-CC	1-IGCC	1-IGCC	------	1-IGCC	1-IGCC	4,227
B.10	----	1-PC	1-PC	1-PC	1-PC	1-CC	1-CC	------	2-CC	4,036
B.11	----	1-PC	1-PC	1-PC	1-PC	1-IGCC	1-IGCC	------	1-IGCC	4,800
B.12	----	1-IGCC	------	1-IGCC	1-IGCC	------	1-IGCC	------	1-IGCC	3,840
B.13	----	1-CC	1-CC	1-CC	2-CC	1-CC	1-CC	------	2-CC	3,465
B.14	----	1-PC	1-PC	2-PC	2-PC	1-PC	------	1-PC	1-PC	5,616
*B.15	----	1-PC	1-PC	2-PC	2-PC	1-PC	------	1-PC	1-PC	6,750

Note:

CT: 125 MW Combustion Turbine
CC: 385 MW Combined Cycle
IGCC: 768 MW Coal Gasification Combined Cycle Unit
PC: 624 MW Pulverized Coal Unit
REP: 286 MW Repowering of Lauderdale
*PC: 750 MW Pulverized Coal Unit

Table IV.G.2

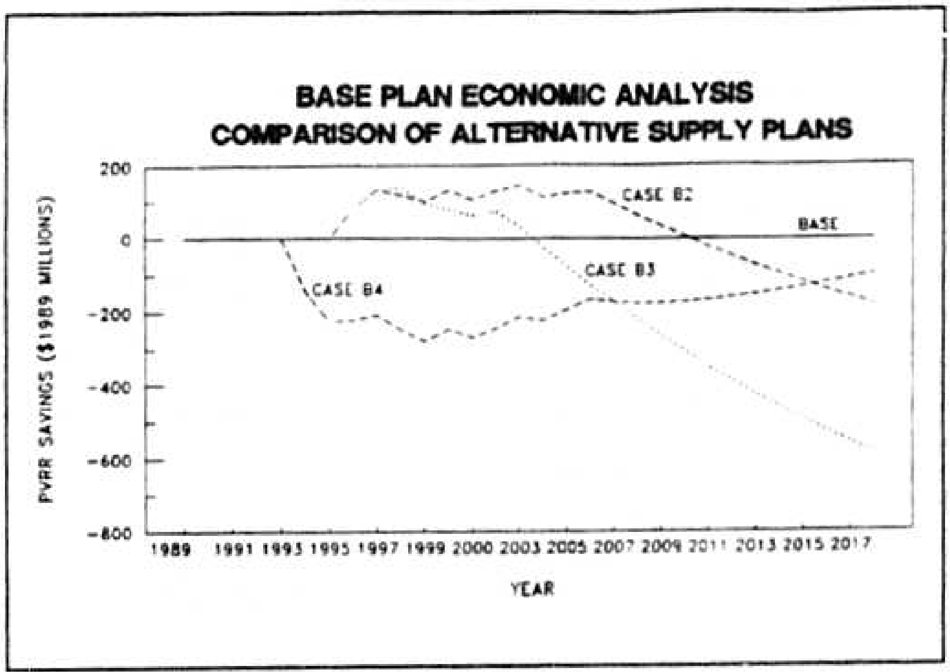


Figure IV.G.1

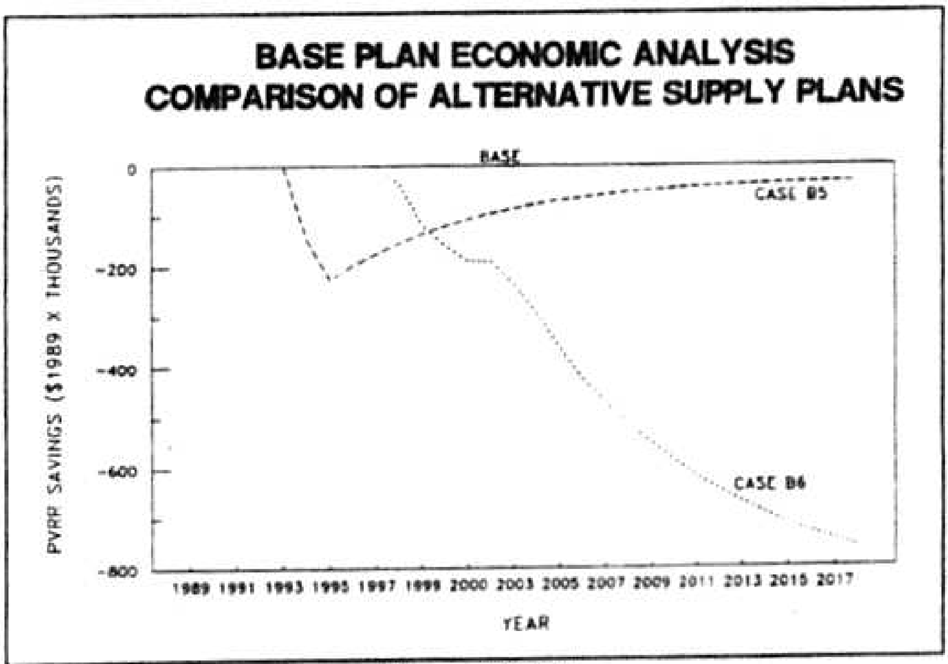


Figure IV.G.2

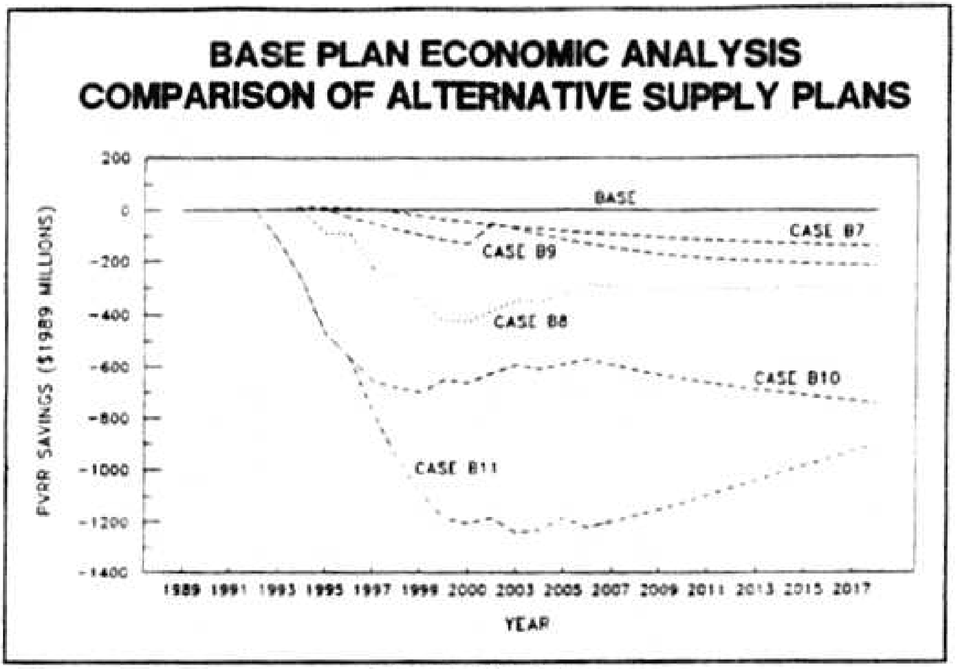


Figure IV.G.3

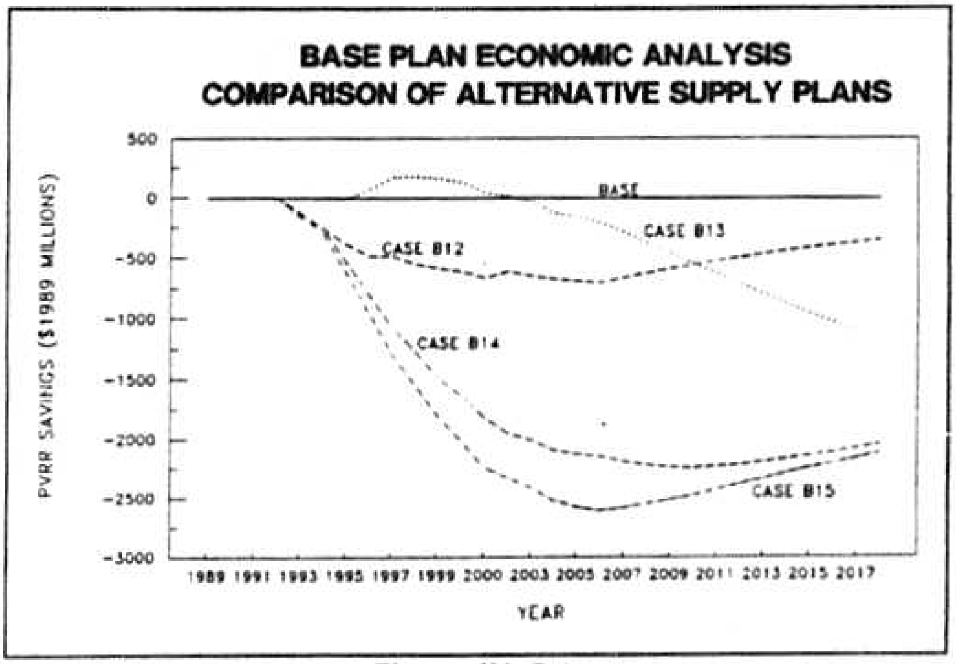


Figure IV.G.4

Table IV.G.3 compares the economic rankings of the alternative plans after twenty, twenty-five and thirty years. The case identified as the Base Plan is the most economic beyond the first twenty years. Case B.2, which replaced the first IGCC unit in the Base Plan with two combined cycle units, appears to be the economic choice when the horizon is limited to twenty years. Case B.2 was not selected to be the Base Plan due to fuel supply limitations as discussed on page 83 with regard to the Reference Plan. Although this case produces savings before the year 2010, the curve shows that nearly $200 million of additional revenue requirements are required by the year 2018.

Determination Of Need
Base Case Optimization

	Generating Units Added 1992-2000					PVRR In Millions					
						1989-2008		1989-2013		1989-2018	
Case	IGCC	PC	CC	CT	REP	PVRR	Rank	PVRR	Rank	PVRR	Rank
Base	3		2		2	26,216	2	31,011	1	34,326	1
B.5	3		2		2	26,270	3	31,050	2	34,358	2
B.2	2		4		2	26,155	1	31,086	3	34,511	5
B.7	2		1	3	2	26,314	4	31,131	4	34,462	4
B.4	4				2	26,395	6	31,166	5	34,427	3
B.9	4		3			26,371	5	31,204	6	34,537	6
B.8	3	2	1		2	26,511	8	31,311	7	34,613	7
B.3		3	4		2	26,438	7	31,435	8	34,912	9
B.12	5		9			26,844	12	31,486	9	34,691	8
B.10		4	4			26,811	11	31,685	10	35,055	10
B.6	1	3	2		2	26,754	10	31,695	11	35,098	11
B.13			9			26,599	9	31,810	12	35,519	13
B.11	3	4				27,466	13	32,114	13	35,282	12
B.14		9				28,454	14	33,229	14	36,403	14
B.15		9				28,776	15	33,367	15	36,478	15

Table IV.G.3

Figure IV.G.3 shows the FPL system net LOLP that results after giving effect to the capacity additions and non-construction alternatives identified in the Base Plan. Except for 1995, the 0.1 day/year target is met through 1997. As shown in Figure IV.G.4, IV.G.4, the Base Plan also maintains better than a 15%

reserve margin at the time of summer peak through 1997. These figures also reflect that, using present planning assumptions, additional capacity has been added in 1998 to meet FPL's dual reliability target.

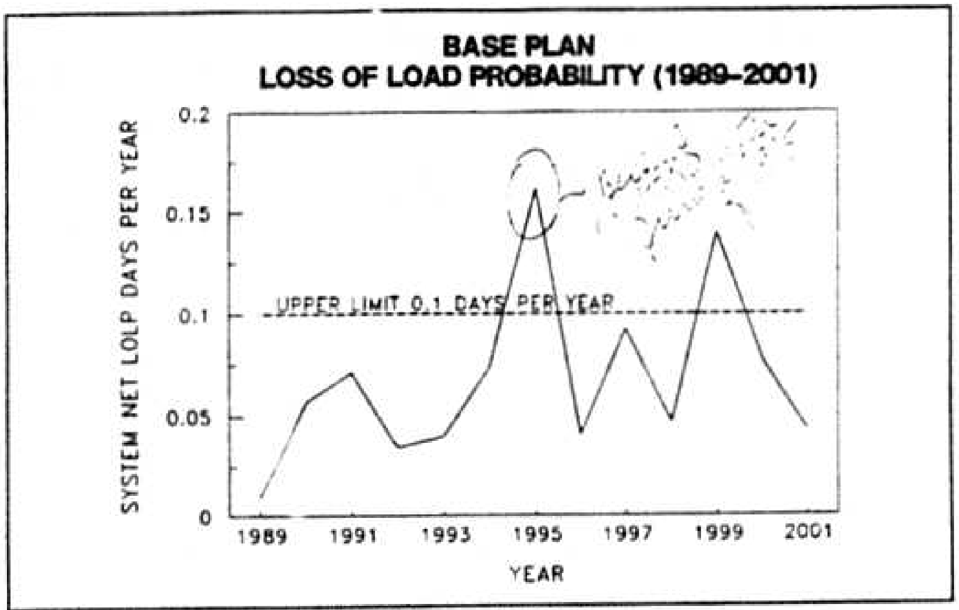


Figure IV.G.5

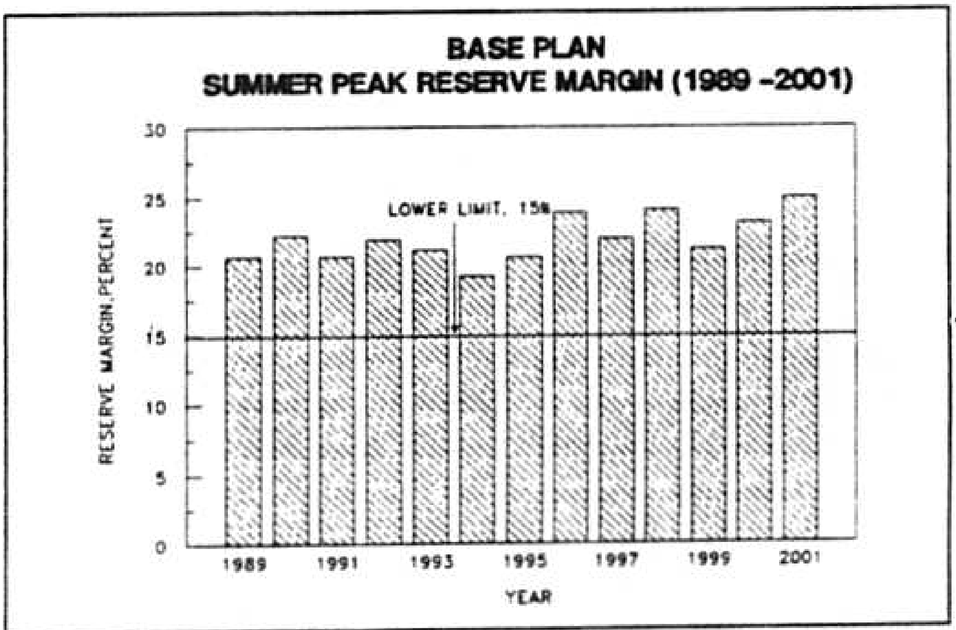


Figure IV.G.6

H. Results Of Sensitivity And Scenario Analyses

The next step in FPL's analysis tested the Base Plan to see how well it responded to changes in the base planning assumptions. As described below, this testing involved both sensitivity analyses, in which one key assumption was examined, and scenario analyses, in which consistent changes were made to a series of related assumptions. These analyses reinforced the selection of the Base Plan, which has some flexibility to accommodate accelerated capacity additions in the event that load growth exceeds expectations or projected non-generating alternatives do not fully materialize and which accommodates conversion to the use of coal in the event of unexpected changes in fuel price levels and relationships.

Sensitivity Analyses

The sensitivity analyses examined the relative economics of the Base Plan and alternatives for a variation in one key variable. These studies do not reflect the interrelationships of variables as considered in the scenario analyses described later in this section. They do provide insight into how changes in a key assumption can affect the relative economics of alternative plans. Four key variables - natural gas availability, economy energy availability, oil and natural gas prices and the load forecast - were examined.

In each of the first two sensitivity cases, the availability of supply of the selected variable (natural gas or economy energy) was reduced by 50%. This level of reduction was chosen to represent a worst case situation. It is very unlikely that reductions of this magnitude would actually be experienced. The results of the natural gas availability sensitivity are presented in Figure IV.H.1. Only selected cases are shown. This sensitivity is expected to improve the economics of coal units and adversely affect the economics of plans with more natural gas fired capacity.

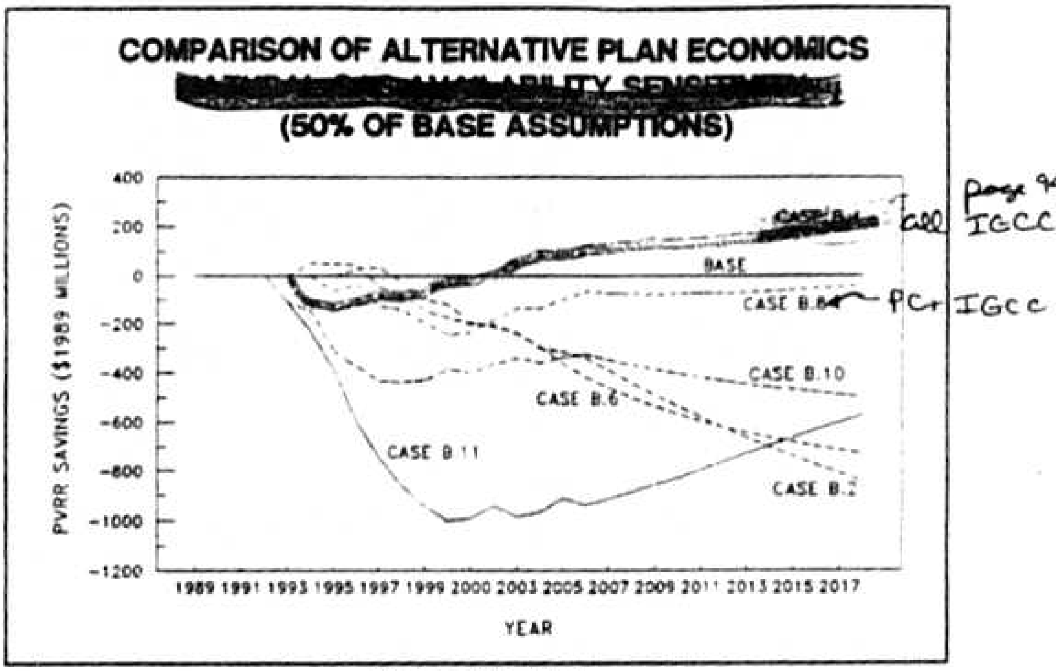
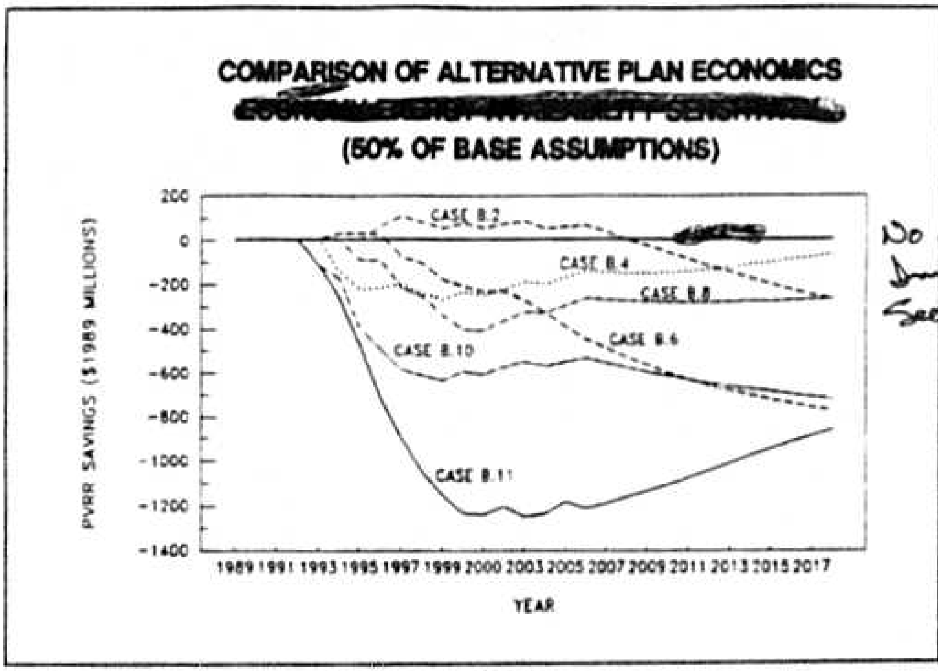


Figure IV.H.1

When compared to the results of analyses under most likely assumptions, the reduction in natural gas availability results in improved economics of cases adding more coal units versus the Base Plan. Cases with more natural gas fired capacity than the Base Plan (B.2), are less economic than when using base case assumptions. The most economic plan, Case B.4, is based on IGCC technology. The conclusion that can be reached from this sensitivity is that if FPL experienced a significant long term reduction in natural gas availability versus the most likely forecast level, addition of coal gasification to the 1994 and 1995 combined cycle units might be appropriate.

The results of the economy energy availability sensitivity are shown in Figure IV.H.2.



No real Impact See page 95-96

Figure IV.H.2

A 50% reduction in the availability of economy energy slightly improves the economics of coal units relative to the natural gas fired units in the Base Plan. However, the difference is not significant enough that a plan other than the Base Plan would be selected.

Neither of these sensitivities suggests that the Base Plan should be altered. Instead, they reinforce the strategic advantages of a combined cycle based plan. The ability to add coal gasification to the units when economically attractive provides a great deal of planning flexibility. If the base assumptions on natural gas and economy energy should turn out to be wrong, a combined cycle plan does not forego the use of coal as a fuel. Gasification can be added in response to unforeseen changes in these forecasts, deferring capital expenditures until they are required.

The third sensitivity, varying oil and natural gas prices, was a break even analysis to show at what price level the addition of coal gasification facilities to the natural gas fired combined cycle units might be economic. In each case, the 1989 price levels of oil and gas were raised a fixed amount above the most likely forecast, then escalated at the same rates as in that forecast. The results are shown in Figure IV.H.3. The curves show that under most likely fuel price assumptions, gasification does not achieve a break even point in the thirty year study period being analyzed. A 20% increase in the price of oil and gas results in break even in roughly twenty-five years from the in-service date of the unit. Additional increases in price improve the economics of gasification further. A 60% price increase provides a clear advantage to the IGCC.

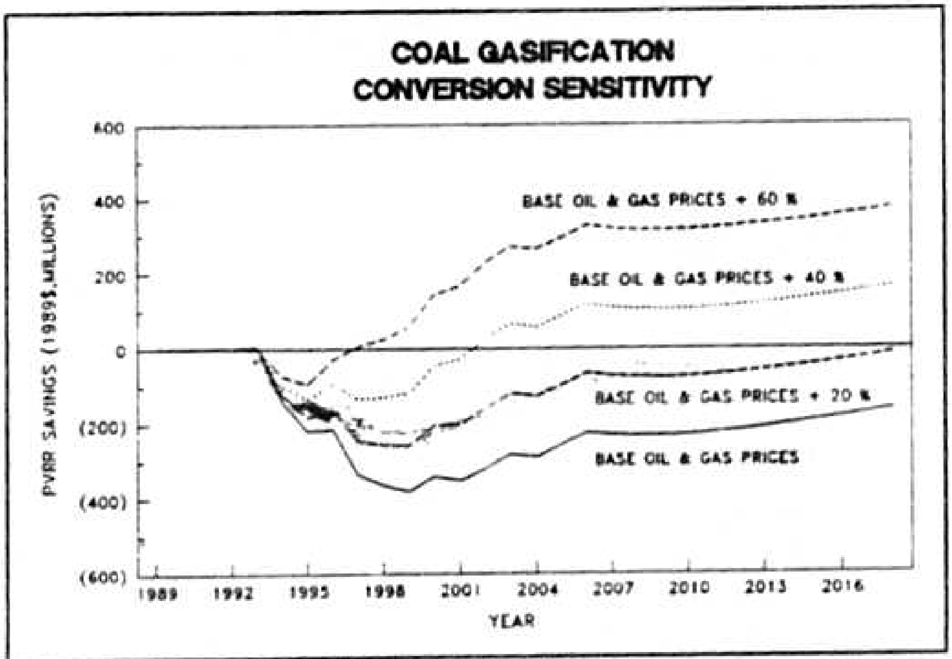


Figure IV.H.3

The final sensitivity, the high load sensitivity, was developed to reflect peak demand and energy based on a fifteen year historical average of temperatures, rather than the thirty year average used in the base forecast. The resultant change in peak demand and energy is shown in Figures IV.H.4 and IV.H.5. This forecast falls between the most likely and high band forecasts presented in *Section III.A.*

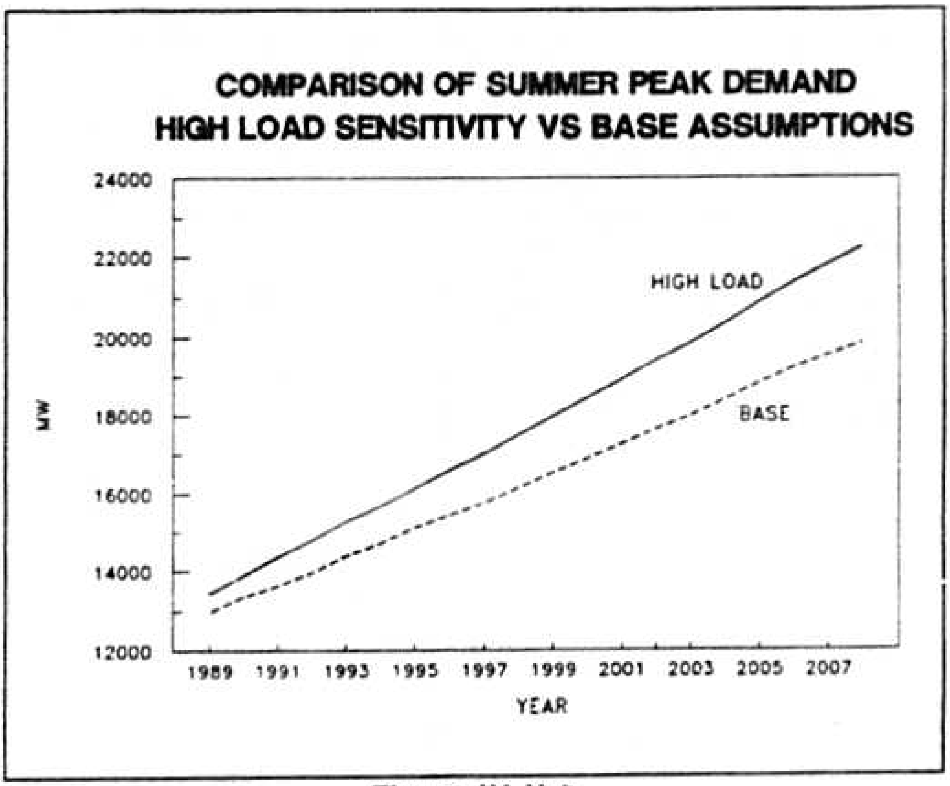


Figure IV.H.4

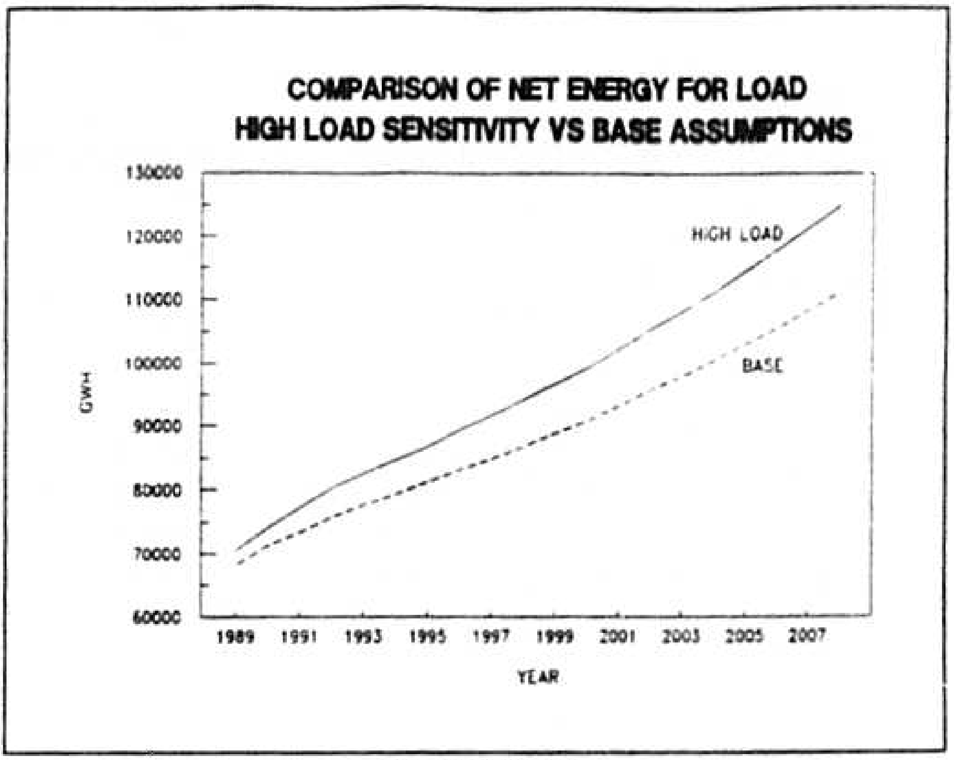


Figure IV.H.5

This sensitivity differs from the others in that the timing and number of new units would be affected by the changed assumption. Table IV.H.1 shows the alternative plans considered to meet the increased demand. Note that capacity would be required in 1992 and that nearly 2,000 MW of additional capacity would be required by the year 2000, compared to the Base Plan.

The results of the economic analysis are shown in Figure IV.H.6. The most economic plan remains a mix of repowering, new combined cycle units and coal gasification combined cycle units.

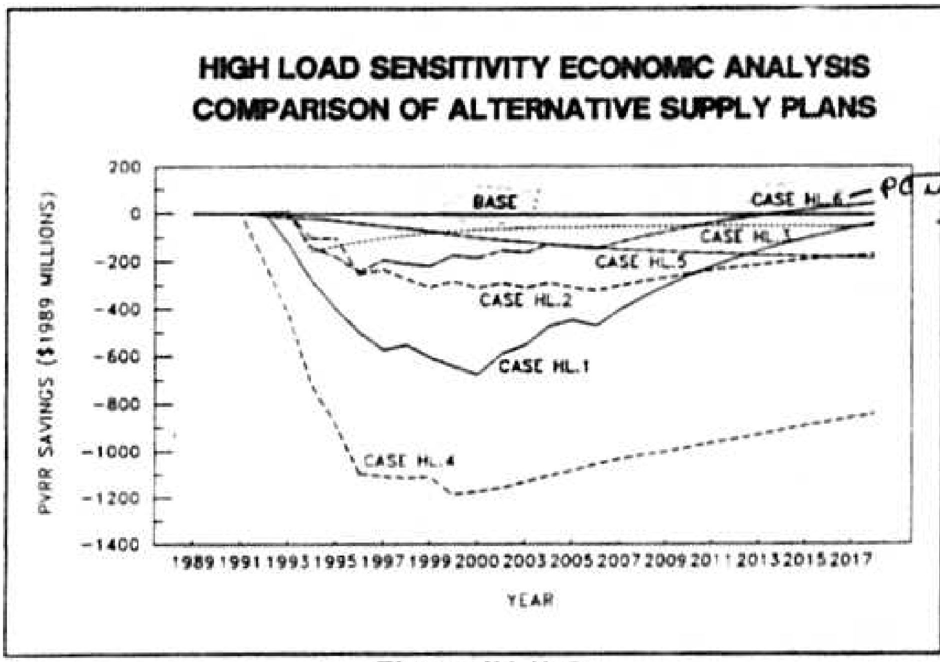
Alternative Expansion Plans Evaluated Under <u>High Load Sensitivity</u>

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total MW
Base	2-REP	2-CC	1-CC	1-IGCC	1-IGCC	1-IGCC	1-IGCC	------	1-IGCC	5,567
HL.1	2-REP	1-IGCC	1-IGCC	1-IGCC	1-IGCC	1-IGCC	------	1-IGCC	1-IGCC	5,948
HL.2	2-REP	2-CC	1-PC	1-PC	2-IGCC	------	1-IGCC	------	1-IGCC	5,662
HL.3	1-CC	2-CC	1-IGCC 1-CC	------	1-IGCC	1-IGCC	1-IGCC	------	1-IGCC	5,380
HL.4	1-IGCC	1-IGCC	1-IGCC	1-IGCC	1-IGCC	------	1-IGCC	------	2-IGCC	6,144
HL.5	4-CT	2-CC	1-CC	1-IGCC	1-IGCC	1-IGCC	1-IGCC	------	1-IGCC	5,495
HL.6	2-REP	2-CC	1-IGCC	1-IGCC	1-PC	1-PC	1-IGCC	------	1-IGCC	5,662

Note:

CT: 125 MW Combustion Turbine
CC: 385 MW Combined Cycle
IGCC: 768 MW Coal Gasification Combined Cycle Unit
PC: 624 MW Pulverized Coal Unit
REP: 286 MW Repowering of Lauderdale

Table IV.H.1



PC 1996, 1997

Figure IV.H.6

In addition, from a strategic point of view, the plan consisting of repowering, combined cycle and coal gasification combined cycle units is advantageous in meeting unexpectedly high load growth. Since these units include combustion turbines, which can be installed with relatively short lead times, the new capacity requirements can be met by phasing in the combustion turbines, followed by the addition of the steam cycle and coal gasification as soon as is feasible. This phasing option preserves the long term economics of the plan while providing flexibility in meeting system reliability requirements.

Scenario Analyses

Scenario analyses reflect the interrelationships between variables, such as the effect of energy prices on load growth. In examining the economics of an expansion plan in a scenario approach, new alternative plans must be developed to respond to changes in demand. FPL has examined two scenarios in addition to the most likely scenario:

- Effective OPEC Cartel
- Oil Shock

Tables IV.H.2 and IV.H.3 list the alternative expansion plans evaluated under the respective scenarios. Rather than rerun a full set of alternative plans for each scenario, a small number was generated to be tested against the Base Plan. The alternatives were designed to test the addition of more coal capacity to the plan, since both scenarios adversely affect the economics of natural gas and oil fired units.

Alternate Expansion Plans Evaluated Under Effective OPEC Cartel Scenario

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total MW
Base	------	2-REP	1-CC	1-CC	1-IGCC	------	1-IGCC	------	1-IGCC	3,646
EO.2	------	------	1-REP	1-REP 1-IGCC	1-IGCC	------	1-IGCC	------	1-IGCC	3,644
EO.3	------	------	1-REP	1-REP 1-CC	1-CC 1-PC	------	1-PC	1-IGCC	------	3,358
EO.4	------	------	1-CC	1-CC	2-CC	1-IGCC	------	------	1-IGCC	3,076
EO.5	------	------	1-IGCC	------	1-IGCC	1-IGCC	------	1-IGCC	1-IGCC	3,840
EO.6	------	------	2-CT	2-CT 1-CC	1-CC	1-CC	1-IGCC	------	1-IGCC	3,191
EO.7	------	------	1-REP	1-REP 1-CC	1-CC 1-IGCC	------	1-IGCC	------	1-PC	3,502
EO.8	------	------	1-REP	1-REP 1-CC	1-CC	1-CC	1-IGCC	------	1-IGCC	3,263

Note:

CT: 125 MW Combustion Turbine
CC: 385 MW Combined Cycle
IGCC: 768 MW Coal Gasification Combined Cycle Unit
PC: 624 MW Pulverized Coal Unit
REP: 286 MW Repowering of Lauderdale

Table IV.H.2

Alternate Expansion Plans Evaluated Under Oil Shock Scenario

Plan	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total MW
Base	------	2-REP	1-CC	1-CC	1-IGCC	------	1-IGCC	------	1-IGCC	3,646
OS.2	------	1-CC	1-CC	1-IGCC	1-IGCC	------	1-IGCC	------	1-IGCC	3,842
OS.3	------	1-REP	1-REP 1-IGCC	1-CC	1-IGCC	------	1-IGCC	------	1-IGCC	4,029
OS.4	------	1-IGCC	------	1-IGCC	1-IGCC	------	1-IGCC	------	1-IGCC	3,840
OS.5	------	1-PC	1-PC	1-IGCC	1-IGCC	------	1-IGCC	------	1-IGCC	4,320

Note:

CT: 125 MW Combustion Turbine
CC: 385 MW Combined Cycle
IGCC: 768 MW Coal Gasification Combined Cycle Unit
PC: 624 MW Pulverized Coal Unit
REP: 286 MW Repowering of Lauderdale

Table IV.H.3

The effective OPEC cartel scenario reflects not only significantly higher oil and natural gas prices than the FPL most likely forecast, but also increased availability of natural gas. Reduced demand for electricity and higher inflation resulting from the increased oil prices are included in the scenario. Figure IV.H.7 shows a comparison of natural gas and oil prices used in this scenario versus the Base Case. Figure IV.H.8 shows the natural gas availability used in the effective OPEC cartel scenario versus the Base Case.

The oil shock scenario is premised on a mid-1990's oil price shock similar to the price movement of the 1970's. The timing of the oil price shock was selected to correspond to the in-service dates of the natural gas fired units in the Base Plan for maximum effect. Corresponding changes in electrical demand and inflation were reflected in the scenario. A comparison of oil and natural gas prices used in this scenario with those used in the base assumptions is shown in Figure IV.H.9.

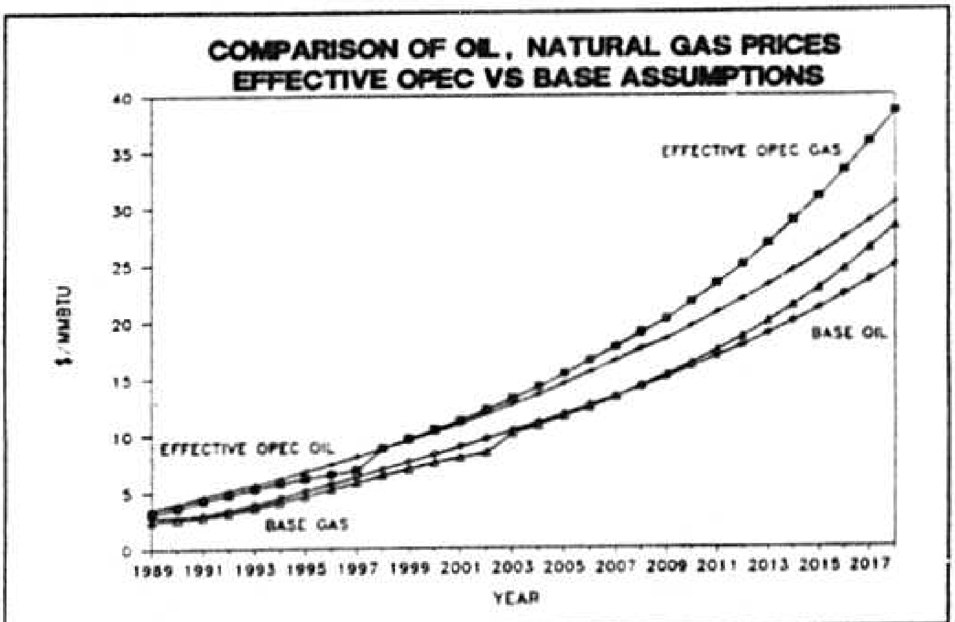


Figure IV.H.7

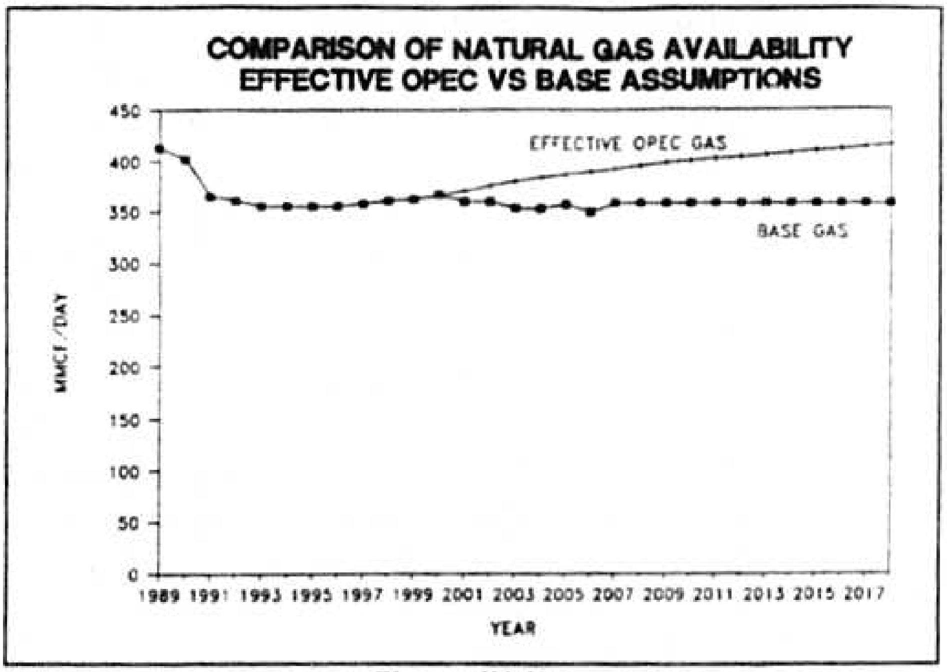


Figure IV.H.8

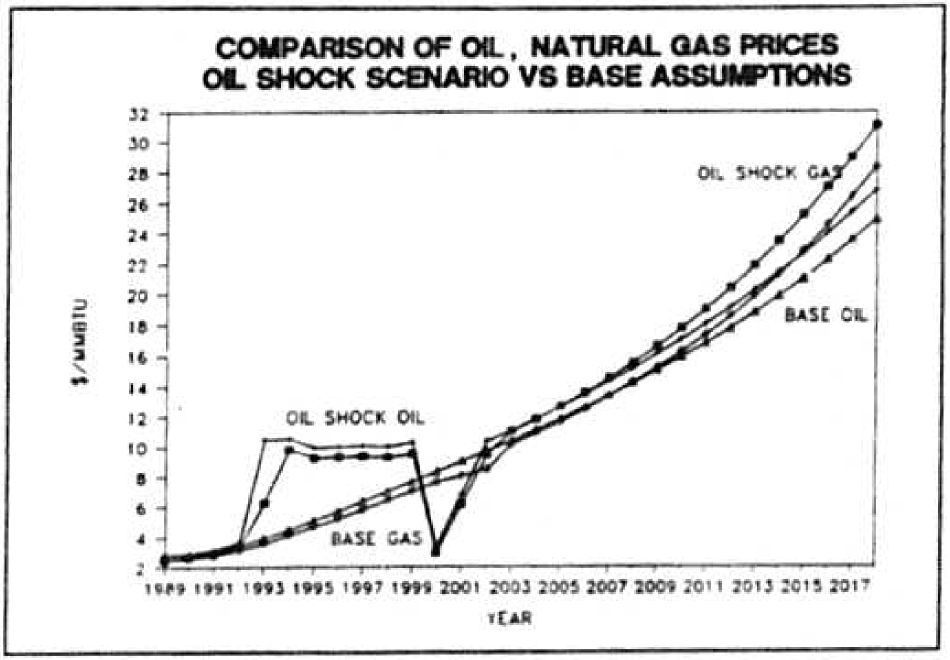


Figure IV.H.9

The results of the economic analyses of the effective OPEC cartel scenario, illustrated in Figure IV.H.10, show improved economics of coal based options. Cases EO.2 and EO.5, which have more IGCC generation than the Base Plan, both show significant savings over the Base Plan. Case EO.2, which includes repowering, continues to have an economic advantage over Case EO.5, which is an all IGCC based plan. The remainder of the cases show a loss over the thirty year period.

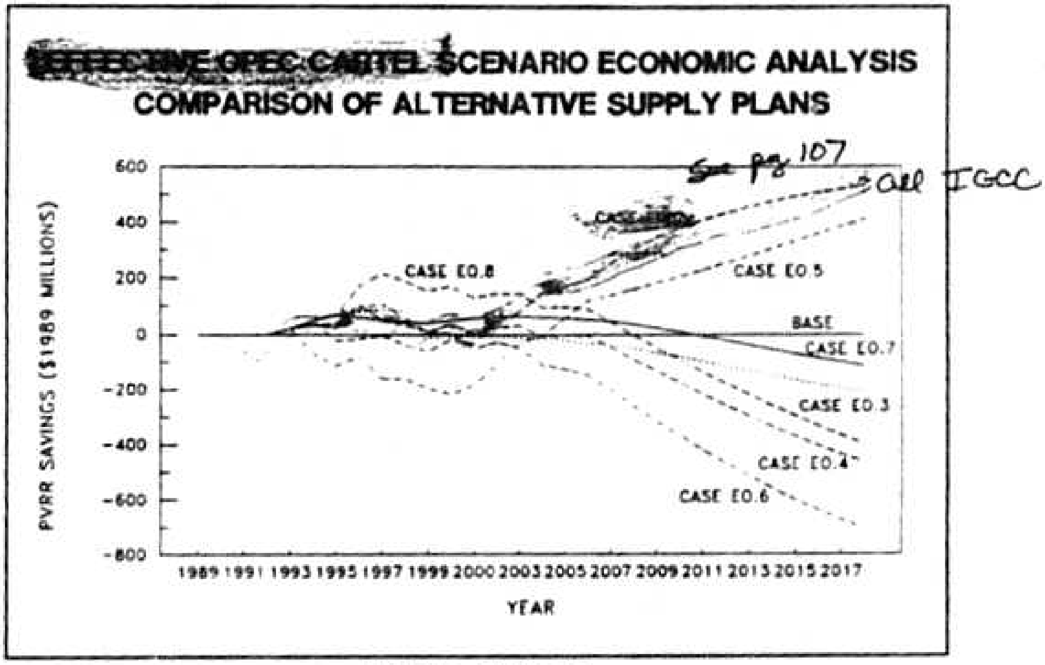


Figure IV.H.10

The economic analysis of the oil shock scenario presented in Figure IV.H.11 again shows improved economics of coal based options versus the Base Plan. The best economics in this analysis are presented by Case OS.4, which is an all IGCC based plan.

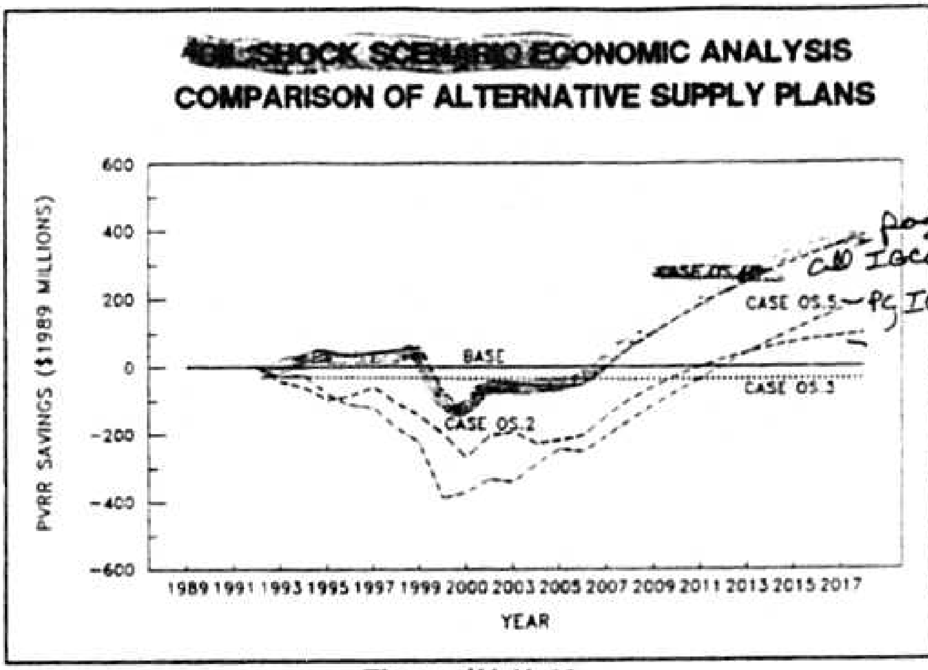


Figure IV.H.11

As was the case with the sensitivity analyses, the results of the scenario analyses reinforce the selection of the Base Plan. They highlight the flexibility of a combined cycle based plan, showing that changes in demand growth can be met by phased construction and changes in fuel price conditions can be met by fuel conversion through coal gasification. In every scenario, a combined cycle alternative is cost competitive and offers more flexibility than a plan based on more conventional pulverized coal units.

I. Strategic Assessment Of The Base Plan

The Base Plan, which consists of a mix of repowering, combined cycle units and coal gasification combined cycle units, has been shown to be the plan which provides the best overall economics over a thirty year planning horizon. The performance of this plan versus alternative supply plans is now examined in light of the strategic considerations presented in *Section II.H*.

Protection Of The Environment

The effects of the Base Plan on air and water quality must be compared to those of the alternative technologies available to FPL in the 1992-1997 time frame. After pursuing non-construction options, the Base Plan uses a mix of fuels which minimizes the impact on the environment. Natural gas is a clean burning fuel, producing little or no sulfur emissions and less carbon dioxide than a coal burning unit. While coal will be used in a gasification unit, that technology has the potential for reducing sulfur emissions below those of a conventional pulverized coal unit with scrubbers. NO_x reductions may also potentially be controlled to levels lower than those produced by the direct firing of coal. Similar improvements in water usage and solid waste production have also been projected for IGCC units, compared to pulverized coal units.

Conservation Of Natural Resources

All of the units proposed in the Base Plan most efficiently use their respective primary fuels. Repowering adds efficient capacity to the system and improves the efficiency of 274 MW of existing capacity by over 20%. Coal gasification results in electricity production from coal which is over 10% more efficient than conventional coal technologies. The plan achieves these efficiencies by incorporating new, advanced design, combustion turbines.

Customer Retention And Customer Choice

The Base Plan has incorporated this strategic element by utilizing a cost effective level of customer oriented programs, such as conservation, interruptible rates and load management. By offering these programs, FPL customers may choose a level of service and price which suits their needs.

Economic Risk To The Customer

In evaluating the overall economics of alternative expansion plans, FPL has selected a plan which provides the best economics without overreliance on a single fuel source. This plan will not require FPL customers to invest in large capital projects and rely on later fuel escalation to recover the investment. However, if high fuel escalation should occur, FPL may still switch fuels when economic, by converting the natural gas fired units in the Base Plan to use coal gas.

Fuel Flexibility

All of the units proposed in the Base Plan will be capable of burning natural gas or coal gas. As discussed above, the ability to defer capital while retaining the ability to utilize coal as a fuel, via conversion, provides a high degree of fuel flexibility.

Flexibility To Respond To Changes In Demand Growth

The ability of a power supply plan to respond to changes in demand growth is best measured by the changes which can be implemented when a sudden increase occurs. A plan which is constructed around combustion turbines (CTs) provides a high level of flexibility, since CTs can be most rapidly added to the system to meet reliability requirements and later phased into combined cycle operation to improve economics. Of course, demand growth can also decline, but here too, the Base Plan reflects an advantage over alternative plans which require high capital investment. If capacity must be delayed or deferred due to reduced demand, units which can be phased to better match load growth offer a strategic benefit.

Operational Flexibility

The Base Plan, when viewed in combination with the alternatives to new construction, represents a balanced approach to meeting system needs for operational flexibility, by meeting future needs with all available resources. Beyond this balance, however, the natural gas fired units incorporated in the Base Plan are suited to a high degree of cycling, if required, and combined with the coal gasification units, are well suited to FPL's expected load shape.

Financial Integrity Of FPL

The Base Plan represents an aggressive use of new, advanced technologies. While there is some risk in this approach, the plan is financeable and does not pose an undue risk to FPL.

Regulatory Uncertainty

Much of the uncertainty surrounding the future power supply plan involves environmental concerns. The ability of the Base Plan to meet environmental requirements has been addressed in the discussion in the section dealing with protection of the environment. The shorter lead times of the units selected, when compared to pulverized coal units, also enables FPL to better deal with uncertainty, shortening the horizon over which all relevant parameters, including regulatory issues, must be forecast.

In the final analysis, the FPL Base Plan represents the best combination of overall economics, and an ability to meet the strategic needs of FPL and its customers.

J. Consistency Of The FPL Plan With Peninsular Florida Needs

The need for new capacity in peninsular Florida was most recently studied in the 1989 Annual Planning Hearing on Load Forecasts, Generation Expansion Plan and Cogeneration Prices (APH), FPSC Docket No. 890004-EU. In that proceeding, a statewide study was performed by the Florida Electric Power Coordinating Group, Inc. (FCG), resulting in the schedule of unit additions shown in

Table IV.J.1 Also shown in Table IV.J.1 is the schedule of FPL unit additions as presented in this document.

Schedule Of Unit Additions
Peninsular Florida Versus FPL

	Peninsular Florida[1/] Long Range Planning Study		FPL	
Year	Unit Additions	MW	Unit Additions	MW
1992	Combined Cycle	220	----------------	---
1993	Combustion Turbine Combined Cycle	150 880	Repowering Lauderdale 4, 5	572
1994	Combined Cycle	880	Combined Cycle	385
1995	Combustion Turbine Combined Cycle	225 660	Combined Cycle	385
1996[2/]	Unspecified	795	Integrated Coal Gasification Combined Cycle	768
1997[2/]	Unspecified	795	----------------	---

[1/] 1989 Planning Hearing "Generating Expansion Planning Studies," Florida Electric Power Coordinating Group, Inc., pages 54-55.

[2/] The FCG filing showed only total MW of capacity needed after 1995, without specifying unit type.

Table IV.J.1

This comparison shows that the FPL expansion plan is consistent with the results of the FCG Long Range Planning Studies. The type of units added and the size and timing of those units match the FCG results through 1995, which is the last year for which the FCG study identified unit types. For 1996, FPL has identified an IGCC option whose size is consistent with the statewide capacity need in that year.

Although the FCG study did not select any IGCC units, that study did not identify 1996 unit additions by type and used IGCC unit performance data from the *EPRI Technical Assessment Guide* (TAG).

FPL evaluated the IGCC option based on more recent data from a detailed site-specific study, performed under EPRI sponsorship in partnership with Fluor Daniel, Inc., Shell Oil Company and General Electric Company. This data shows the IGCC to be economically viable on the FPL system in the 1996 time frame.

V. UNIT SPECIFIC INFORMATION

A. Design Basis And Cost Data

The capacity requirements identified in the Base Plan have been separated into two specific projects, as shown in Table V.A.1. The basis for the selection of the Lauderdale and Martin sites is described in *Section V.B.*

New Capacity Requirements Projects
• Lauderdale Repowering Project
• Martin Expansion Project

Table V.A.1

Each of these projects consists fundamentally of combined cycle units. A combined cycle unit is a hybrid of combustion turbines and a steam driven turbine generator. Each of the combustion turbines compresses outside air into a combustion area where fuel, typically natural gas or oil, is burned. The hot gasses from the burning fuel air mixture drive a turbine, which in turn rotates a generator that produces electricity. In combined cycle operation, the hot exhaust gasses produced by each combustion turbine are passed through a heat recovery steam generator (HRSG) which produces steam. This steam is used to drive an additional turbine generator. The utilization of waste heat from the combustion turbines provides an overall plant efficiency that is much better than that of the CTs or the simple cycle steam electric generator alone.

Each of the proposed FPL combined cycle units is based on the use of advanced combustion turbines. The primary difference between advanced CTs and conventional CTs is their efficiency. This difference results from higher firing temperatures made possible by advances in design. FPL has selected designs based on advanced CTs because they are more economical than conventional CTs at the capacity factors at which they are expected to operate on the FPL system.

Each of the combined cycle units (including the repowered Lauderdale units) is a 400 MW class unit. Because FPL's planning is based on its need to meet summer peak demand, all analysis is based on the expected summer net ratings of the proposed units, which are reported below. The actual summer net ratings may vary, based on final design and the results of performance testing.

The specific configuration and the projected costs of the Lauderdale Repowering and the Martin Expansion Projects are described below. This information reflects preliminary design specifications that were prepared solely for use in developing a base cost estimate. Detailed engineering has not yet been completed for either project.

<u>Combustion Turbine Unit Repowering</u>

FPL has studied the feasibility of repowering some of its oil/gas fired units with new advanced combustion turbines. Repowering involves the integration of new combustion turbine units with existing steam electric generators to create combined cycle units. As discussed in *Section V.B*, FPL chose Lauderdale Unit Nos. 4 and 5 as the preferred candidates for repowering. Based on experience gained from the Lauderdale repowering, FPL may consider repowering of other oil/gas fired units as a future capacity option. The configuration chosen by FPL for repowering the Lauderdale Units is shown in Figure V.A.1.

The existing 150 MW class Lauderdale units each have a summer net capacity of 137 MW. Under the proposed repowering configuration, two new advanced CTs will be added to each Lauderdale unit. The

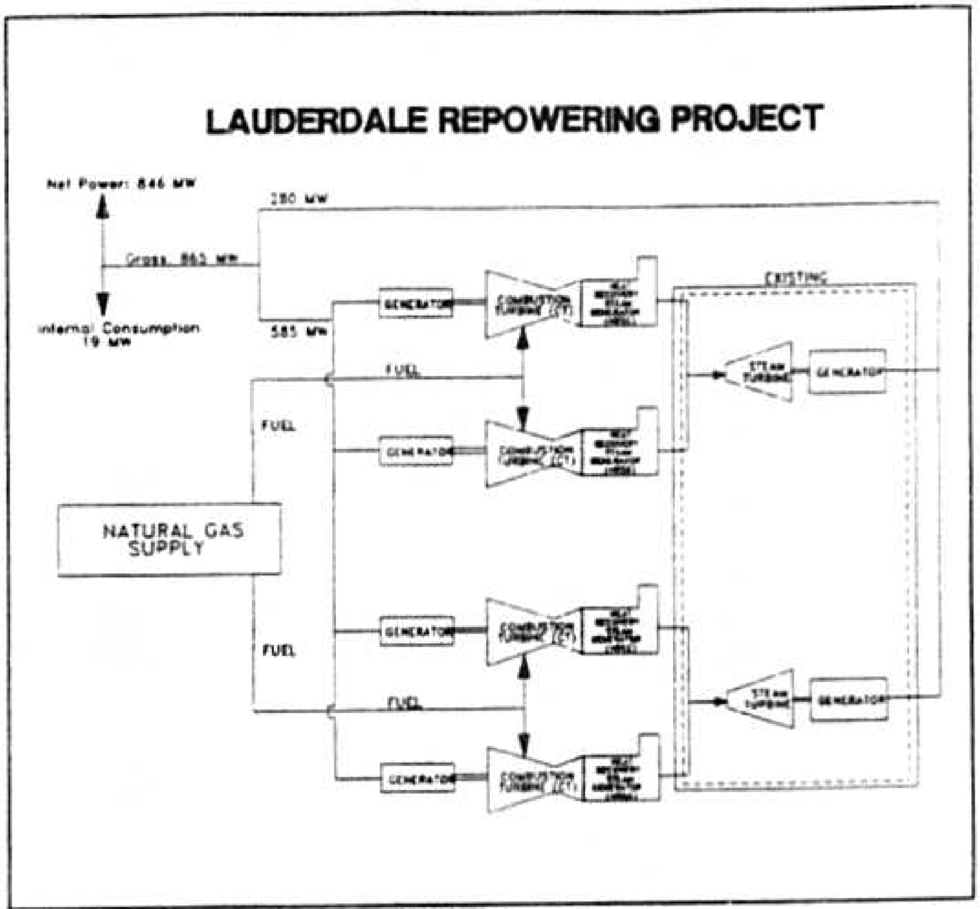


Figure V.A.1

exhaust from these CTs will be captured in new heat recovery steam generators (HRSG's) that will be used to drive the existing steam turbine. FPL assumed for study purposes that after repowering each Lauderdale Unit would have a net summer capacity of 423 MW, or an increase in net capacity of 286 MW. Of the 423 MW total for each unit, approximately 283 MW will be supplied by the new CTs and approximately 140 MW by the repowered steam generator.

In addition to providing increased capacity, the conversion of the existing units to combined cycle operation results in an overall improvement in efficiency, since the heat rate of the repowered units is lower than that of either the original oil/gas fired generator or the new combustion turbines.

The repowered units will use natural gas as their primary fuel with distillate as a back-up fuel. The units are capable of future conversion to burn coal gas as an alternate fuel. Coal gas would have to be transported to the site from a remote coal gasifier because the Lauderdale Site cannot accommodate coal gasification facilities.

Unit Cost Of Repowering

The total installed cost for repowering both Lauderdale 4 and 5 is projected to be approximately $468,000,000. The total cost for the project is shown in Table V.A.2.

Total Cost
Repowering Lauderdale Units 4 & 5

Direct Costs	$301,510,000
Indirect Costs	$ 47,942,000
Total Construction (1989 Dollars)	$349,452,000 $611/KW
Escalation To In-Service Year Dollars	$ 22,300,000
Contingency	$ 48,658,000
AFUDC	$ 47,590,000
Total Installed Cost	$468,000,000 $818/KW
Transmission (On-Site)	$ 6,500,000
Total Project Cost	**$474,500,000**

#329

Note: $/KW are based on the increase of the units' summer rating

Table V.A.2

Martin Combined Cycle Units

The Martin Combined Cycle Project consists of two 400 MW class combined cycle units, each with a net summer capacity of 385 MW. Each combined cycle unit consists of two advanced combustion turbines fired on natural gas, with distillate oil as a back-up fuel, plus two HRSG's and a related steam turbine. The configuration of these combined cycle units is shown in Figure V.A.2.

These combined cycle units are capable of conversion to burn gasified coal in the event that future price and economic conditions justify the addition of a gasifier. Coal transportation, unloading, handling and storage facilities will be available at the Martin site following the installation of the 1996 IGCC plant.

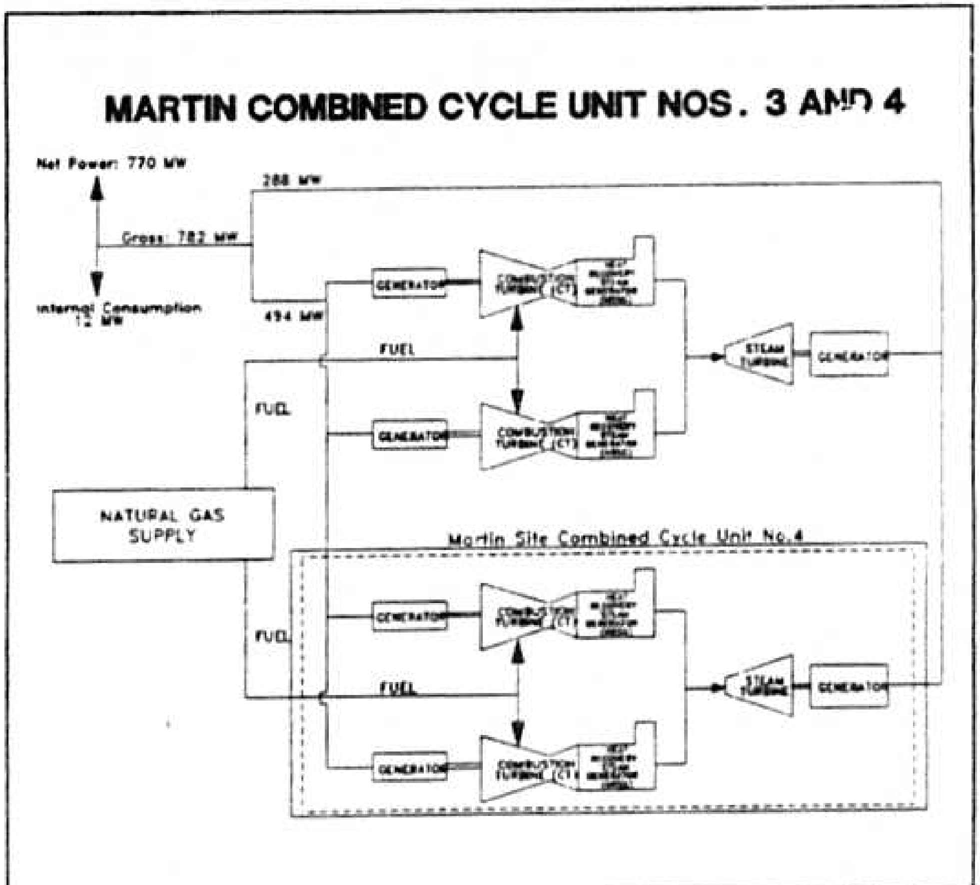


Figure V.A.2

Unit Cost Of New Combined Cycles

The total installed cost for two new combined cycle units with in service dates of 1994 and 1995 is estimated to be $632,0C0,000, including escalation and AFUDC. The total cost for the project is shown in Table V.A.3.

Martin Integrated Gasification Combined Cycle Units (IGCC)

This option consists of two 400 MW class combined cycle units, each with a net summer capacity of 384 MW, and a multi-train integrated coal gasification plant. The plant is designed for low capital investment and high overall plant efficiency. The two combined cycle units which make up the power block consist of four advanced combustion turbines (CTs), four heat recovery steam generators (HRSG's) and two steam turbines. The gasification plant was sized to supply full load requirements to the combustion turbines. The unit operations included in the IGCC are shown in Table V.A.4.

Total Cost
Two Martin Combined Cycle Units

Direct Costs	$353,855,000
Indirect Costs	$ 67,718,000
Total Construction (1989 Dollars)	$421,573,000 $548/KW
Escalation To In-Service Year Dollars	$ 80,396,000
Contingency	$ 54,842,000
AFUDC	$ 75,189,000
Total Installed Cost	$632,000,000 $821/KW
Transmission (On and Off-Site)	$ 44,000,000
Total Project Cost	#878 **$676,000,000** [illegible]/KW

Note: $/KW are based on unit summer net rating

Table V.A.3

Figure V.A.3 shows the configuration of the Combined Cycle Unit Nos. 5 and 6.

Unit Operations Included In The IGCC

- Coal receiving and handling
- Coal drying and pulverization
- Oxygen plants
- Coal gasification
- High temperature gas cooling
- Particulate removal
- Gas treating and cooling
- Acid gas removal
- Sulfur recovery
- Tail gas treating
- Fuel gas saturation
- Combustion turbines
- Steam cycle
- Miscellaneous water treatment facilities
- General facilities
- By-product storage

Table V.A.4

Unit Costs Of New Integrated Coal Gasification Combined Cycles

The total installed cost for two new coal gasification combined cycle units with an in-service date of 1996 is estimated to be $1,712,000,000, including escalation and AFUDC. The total cost for the project is shown in Table V.A.5.

B. Site Selection

The identification of the Lauderdale Units as the preferred candidates for repowering and the selection of the Martin site as the preferred location for the construction of the new combined cycle and IGCC units are the result of site evaluation and selection efforts that began in the 1970's.

Total Cost
Two Coal Gasification Combined Cycle Units

Direct Costs	$ 842,346,000
Indirect Costs	$ 182,020,000
Total Construction (1989 Dollars)	$1,024,366,000 $1,334/KW
Escalation To In-Service Year Dollars	$ 218,134,000
Contingency	$ 207,736,000
AFUDC	$ 261,764,000
Total Installed Cost	$1,712,000,000 $2,229/KW
Transmission (On-Site)	$ 9,000,000
Total Project Cost	**$1,721,000,000**

Note: $/KW are based on unit summer net rating

Table V.A.5

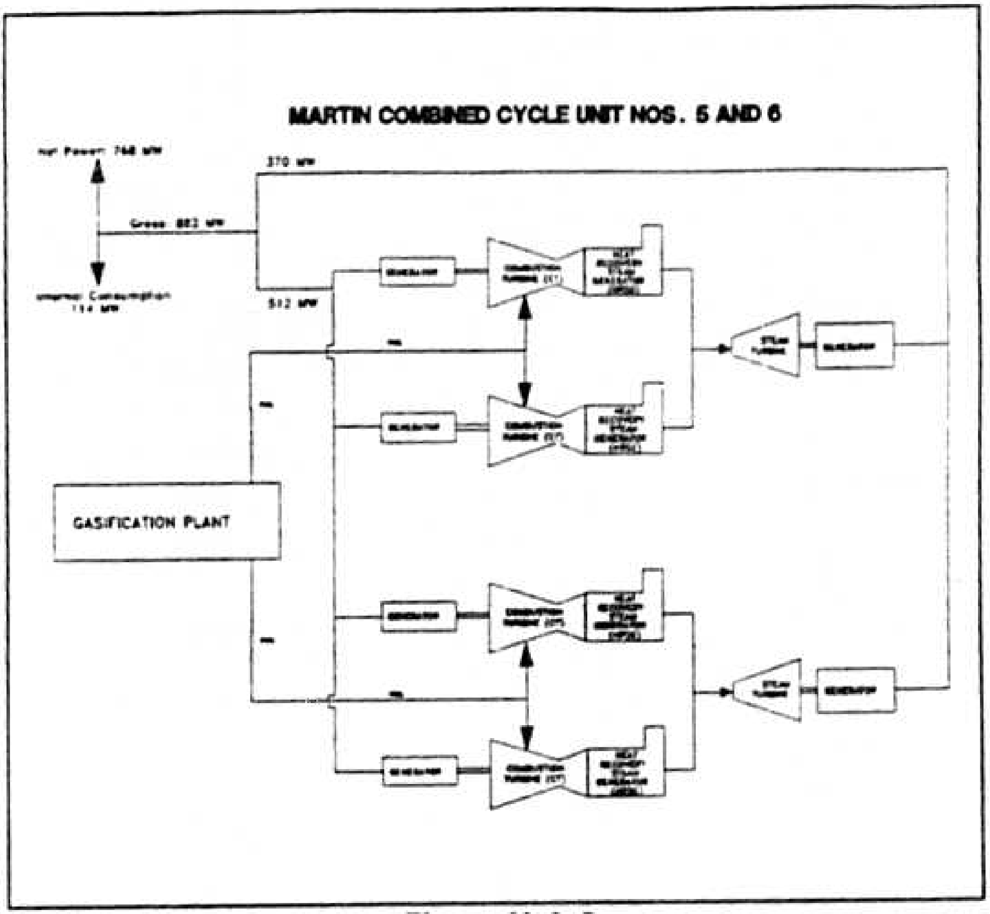


Figure V.A.3

1979 Coal Plant Siting Study

By the mid-1970's, FPL's forecasts indicated that peak demand on its system would continue to rise as a result of population growth, despite reductions attributable to energy conservation and load management. That growth required additional generating capacity as early as 1985. FPL's experience with rising oil prices caused it to recognize a need for greater fuel diversity on its system. Because planning for such facilities must be initiated almost a decade before the earliest possible need date, FPL organized a "Coal Project" to carry out the necessary evaluations and studies in 1978.

One of the first tasks of the Coal Project was to conduct a siting study (the "1979 Siting Study"). The goal of that study was to identify the most favorable site in a twenty-five county region of South and Central Florida for construction of a coal plant consisting of two 700 MW class generating units. The five specific study objectives supporting that overall goal are listed in Table V.B.1.

Objectives 1979 Siting Study
1. Identify broad, favorable siting areas in the region.
2. Assemble a comprehensive list of potential sites.
3. Select a small number of candidate sites.
4. Evaluate and rate these sites.
5. Recommend the preferred site for a coal fired power plant.

Table V.B.1

The methodology used in the site selection study was designed to identify those sites that were most compatible with the environment and that had the greatest potential for licensing. The methodology consisted of a three stage sequential screening process that began with the identification of 270 potential sites and progressed to a detailed environmental and economic evaluation of the ten best candidate sites. The three major steps in that process are described in more detail in Table V.B.2.

The study resulted in identification of an existing FPL site in Martin County (the current Martin Site where two oil fired generating units were under construction) as the preferred location for constructing a nominal 1,400 MW coal fired power plant. Both for environmental and cost factors, this site emerged with a significantly higher rating than the remaining nine candidate sites.

A cooling water pond had already been constructed at the site to serve the units under construction. This pond was sized to

The Major Stages In The Site Selection Methodology For The 1979 Siting Study	
Regional Screening In this stage, the entire twenty-five county study region was examined to identify large areas favorable for siting a coal fired power plant. Such areas have the highest probability of containing environmentally acceptable and licensable sites. A list of 270 potential sites in the study region was developed, but only those sites located in the favorable areas were retained for further consideration.	**Intermediate Screening** The 106 potential sites that passed the Regional Screening were considered in the Intermediate Screening. This second stage involved a two phase screening process based upon both environmental and economic criteria. Using these criteria, ten of the 106 sites were identified as final candidate sites for detailed analysis.
Site Specific Analysis In this third and final stage, the ten candidate sites were evaluated in detail, using a list of twenty-seven environmental siting criteria and three comprehensive, economic criteria. The ten sites were ranked according to numerical site suitability scores, calculated on the basis of site ratings for environmental criteria. A sensitivity analysis was also conducted to determine whether the ranking of the preferred site would change because of variations in the weights or ratings of the environmental criteria. Each site also underwent an in-depth cost analysis based upon the economic criteria.	

Table V.B.2

provide cooling water for approximately 4,000 MW of generating capacity, whereas the oil units under construction were projected to generate about 1,700 MW. Thus, cooling capacity was available for the two 700 MW units anticipated for coal fired generation. The existing cooling system, ongoing site preparations and available transmission system connections were all factors substantially favoring this location in the evaluation of candidate sites.

Energy Capacity Study And South Florida Site Evaluation Study

In 1985, FPL initiated an ongoing yearly project, known as the Energy Capacity Study (ECS), to evaluate both the supply side and the demand side of FPL's overall system needs. Representatives from a number of FPL departments serve as members of the ECS group. The major goal of the annual study effort is to develop long range plans to meet the electric power needs of FPL's customers as reliably and economically as possible, giving due regard to environmental and other strategic considerations. The results of ECS are incorporated into the *Ten Year Power Plant Site Plan* and FPL's Annual Planning Hearing submissions.

As a result of power supply planning analysis in the 1985 and 1986 ECS efforts, a need was identified for additional capacity within the Southeast Florida portion of the FPL system by the mid-1990's. To respond to this need, a South Florida Site Evaluation Study was performed in 1987 to identify a group of preferred sites capable of accommodating several power supply options. Identification of sites was based on environmental resources in the area, as well as engineering and cost considerations. The study consisted of the four individual tasks shown on the following page in Table V.B.3. Because the Martin Site was being evaluated for the entire range of technologies in a separate task, it was excluded from consideration as part of Tasks A and B.

	Specific Tasks Involved In The **<u>South Florida Site Evaluation Study</u>**
<u>Task A</u>:	**Combined Cycle Power Plant** - Identification of preferred sites capable of accommodating two 380 MW combined cycle units.
<u>Task B</u>:	**Gasification Combined Cycle Power Plant and Gasification Plant** - Identification of preferred sites capable of accommodating a 760 MW gasification combined cycle power plant, or a gasification plant capable of supplying synthetic gas to a 760 MW combined cycle plant.
<u>Task C</u>:	**Combined Cycle Repowering** of the Lauderdale, Port Everglades and Turkey Point Plants.
<u>Task D</u>:	**Combined Cycle Power Plant, Gasification Combined Cycle Power Plant or Gasification Plant at the Martin Site.**

Table V.B.3

A progressively complex evaluation methodology (similar to that utilized in the 1979 Siting Study) was used to identify and evaluate candidate sites. The three principal steps in that evaluation were:

- Regional Screening Analysis - Identification of candidate areas from the study area by mapping environmentally sensitive areas.

- Intermediate Screening Analysis - Identification of candidate sites using environmental and cost criteria.

- Site Specific Analysis - Evaluation of candidate sites using twenty-nine environmental criteria and developing site specific costs that included consideration of fuel supply, cooling system design, transmission and site development.

The results of each of the four study tasks are summarized below. In reviewing the results, it is important to note that the range of capital cost estimates for construction at each site were prepared on a consistent basis utilizing conceptual engineering characteristics. While these estimates can therefore be used to compare the relative economics of the various sites, they have not been updated since 1987 and cannot be meaningfully compared to the current cost estimates for the Lauderdale Repowering Project and the Martin Expansion Project. Those estimates have undergone continued refinement and updating as design and licensing efforts have progressed.

<u>Results For Combined Cycle Power Plant Siting (Task A)</u>

In the Regional Screening Analysis, fourteen candidate areas were identified within Dade, Broward and Palm Beach Counties as potentially suitable for combined cycle power plant development. Of these fourteen areas, four were located in Dade County, three in Broward County and seven in Palm Beach County. Four areas were located at existing FPL power plant sites. These candidate areas ranged in size from about twenty-five acres, i.e., just sufficient space to locate a combined cycle plant, to about forty square miles. From these candidate areas, twenty-three candidate sites with at least two cooling system alternatives were identified in the Intermediate Screening Analysis. After performing an environmental screening of candidate sites, costs for sixty-three site and cooling system alternatives were developed. Ten candidate sites were then selected for further evaluation in the Site Specific Analysis. Each of the ten sites was found to be environmentally suitable if measures were taken to mitigate any potential environmental constraints. A list of the preferred sites is presented in Table V.B.4. This table reflects a range of capital costs that account for potential mitigation that may be necessary at each candidate site.

PREFERRED SITES
COMBINED CYCLE POWER PLANT

PREFERRED SITES	CAPITAL[1/] ($000)
FPL Owned Sites With Existing Facilities	
Lauderdale	$333,340-334,850
Port Everglades	$335,261-339,661
Turkey Point[2/]	$362,710-365,826
FPL Owned Sites That Are Undeveloped	
Andytown South	$351,540-359,313
Mowry Canal[2/]	$358,175-369,982
South Dade[2/]	$377,825-380,081
Non-FPL Owned Sites	
Site A	$342,070-353,892
Site B	$351,351-362,539
Site C[2/]	$353,978-365,785
Site D[2/]	$361,892-372,164

[1/] Total base plant capital cost is $299,178,000. The lower portion of the range includes the lowest cooling alternative, while the upper portion of this range includes only those costs to mitigate potential impacts associated with water supply and discharge options.

[2/] Site requires the use of a premium (lower sulfur) fuel oil to meet PSD Class I increments when burned as a secondary fuel. Costs shown do not reflect this operational cost.

Table V.B.4

Results For Gasification Combined Cycle Power Plant And Gasification Plant Siting (Task B)

In the Regional Screening Analysis, eight candidate areas were identified within Dade and Palm Beach Counties as potentially suitable for a gasification combined cycle power plant or gasification plant development. Of these eight areas, three were located in Dade County and five were located in Palm Beach County. These candidate areas ranged in size from about six square miles to about forty square miles. From these candidate areas, eleven candidate sites with at least two cooling system alternatives were identified in the Intermediate Screening Analysis. After performing an environmental screening of candidate sites, costs for twenty-eight site and cooling system alternatives were developed. Six candidate sites were then selected for further evaluation in the Site Specific analysis. Five of these sites were found to be environmentally suitable if measures were taken to mitigate any potential environmental constraints associated with that site. Lists of the preferred sites for a gasification combined cycle plant and gasification plant are presented in Tables V.B.5 and V.B.6, respectively. These tables reflect a range of capital costs that account for potential mitigation that might be necessary at each candidate site.

Results for Combined Cycle Repowering Siting (Task C)

The evaluation for combined cycle repowering focused on FPL's existing steam generating units at the Lauderdale, Port Everglades and Turkey Point sites. These sites were selected based on an assessment of the following strategic factors:

- **Location:** A site near the FPL load center was preferred. The most advantageous sites would therefore be in Dade, Broward or Palm Beach County.

- **Unit Size:** To mitigate technical risk, operational difficulty and the effects on system dispatch during construction, an existing unit of 150 MW to 400 MW nominal size was preferred.

- **Site Infrastructure:** Sites with existing natural gas supply and sufficient transmission capacity were preferred.

- **Site Layout:** Space limitations and impediments to construction were considered in the selection of sites. Congested sites or those with inadequate area to support new facilities were down rated in the final selection.

Preferred Sites
Stand-Alone Gasification Plant

PREFERRED SITES	CAPITAL[1] ($000)
FPL Owned Sites With Existing Facilities	
Turkey Point	$681,273-687,036
Mowry Canal	$672,754-693,766
Non-FPL Owned Sites	
Site E	$609,295-627,469
Site D	$604,668-623,952
Site C	$627,319-648,331

[1]Total base plant capital cost is $542,209,000. The lower portion of the range includes the lowest cooling alternative, while the upper portion of this range includes only those costs to mitigate potential impacts associated with water supply and discharge options.

Table V.B.5

Preferred Sites
Combined Cycle Gasification Power Plant

PREFERRED SITES	CAPITAL[1] ($000)
FPL Owned Sites With Existing Facilities	
Turkey Point[2]	$1,022,584-1,028,347
Mowry Canal[2]	$1,011,665-1,034,677
Non-FPL Owned Sites	
Site E	$940,111-960,285
Site D[2]	$941,577-962,861
Site C[2]	$956,251-979,263

[1]Total base plant capital cost is $841,387,000. The lower portion of the range includes the lowest cooling alternative, while the upper portion of this range includes only those costs to mitigate potential impacts associated with water supply and discharge options.

[2]Site requires the use of lower sulfur fuel to meet PSD Class I increments when burned as a secondary fuel. Costs shown do not reflect this cost.

Table V.B.6

Each of the three sites was found to be environmentally suitable for a repowering project. The capital costs associated with repowering at each of these sites is presented on the following page in Table V.B.7. The costs associated with the three potential sites do not differ significantly. Given comparable costs on a $/KW basis, Lauderdale was selected as the preferred site, as it is best suited to meet the strategic considerations listed above.

Results For Martin Siting
(Task D)

The Martin site was found to be environmantally suitable for a combined cycle plant, a gasification combined cycle plant or a stand alone coal gasifier. No significant potential environmental constraints were identified. Table V.B.8 presents the capital costs for a combined cycle power plant, gasification combined cycle power plant or gasification plant at the Martin Site on a basis consistent with the other portions of the 1987 study.

Summary Of Site Specific Analysis For Repowering Candidate Sites

Candidate Site And Repowering Option	Capital ($000)
Lauderdale Unit 4 233 MW New and 137 MW Existing	$109,604
Lauderdale Units 4 and 5 466 MW New and 274 MW Existing	$223,402
Port Everglades Unit 4 742 MW New and 367 MW Existing	$330,048
Turkey Point Unit 1 742 MW New and 367 MW Existing	$343,275

Table V.B.7

Conclusions

The South Florida Site Evaluation Study showed that a number of environmentally suitable sites exist for all of the technologies under consideration. The final selection of the Lauderdale Units as the primary candidates for repowering and of the Martin site as the preferred location for both the new combined cycle units and the new IGCC plant were based on the following factors:

Summary Of Site Specific Analysis For The Martin Site

Plant	Capital* ($000)
Combined Cycle	$333,013
Gasification Combined Cycle	$882,179
Gasification Plant	$555,747

*Total base plant capital costs are $299,178,000, $841,387,000 and $542,209,000 for a combined cycle and gasification plant, alone

Table V.B.8

- The three potential repowering sites were essentially equal in terms of expected capital cost on a $/KW basis and in terms of system location. In addition, because FPL has not had any prior experience with repowering, it was deemed more prudent to gain that experience through repowering of the smaller

Lauderdale Units (137 MW), rather than the larger Port Everglades or Turkey Point Units (367 MW).

- The existing Martin Plant Site has no significant environmental constraints. As a developed site with an existing cooling pond sized for additional capacity, the impacts associated with developing the Martin Site would be minimized. The Martin site has significantly better economics than the other combined cycle or IGCC sites evaluated, due in large part to the availability of existing cooling pond capacity. The site has sufficient land availability to support both the combined cycle units, an IGCC plant and a potential future coal gasification facility for the combined cycle units. Minimal transmission system upgrades will be required to integrate the new generation into the electric grid. Finally, the site is ideally situated for fuel delivery, having nearby gas pipeline capacity to support the combined cycle units and offering proximity to two competing rail delivery systems.

C. Transmission Requirements

The integration of the Lauderdale Repowering Project and the Martin Expansion Project into the electric grid requires an analysis of expected system conditions after the construction of the units under various interconnection configurations and development of the best engineering alternative to allow delivery of the power to the transmission grid in an economic and reliable manner.

These analyses show that no new off-site transmission lines will be required to integrate the repowered Lauderdale Plant into the electric system, although some on-site transmission work will be required.

The integration of the Martin Combined Cycle Unit Nos. 3 and 4 will require expansion of an existing 230 KV substation at the site and addition of off-site transmission in existing rights-of-way. In particular, a second 230 KV circuit with a normal rating of at least 750 MVA will need to be constructed between the Martin Plant and the Indiantown Substation, a total distance of approximately twelve miles. Following addition of that circuit, the existing Martin-Indiantown 230 KV circuit will have to be reconductored to upgrade it to a normal rating of at least 750 MVA.

The integration of the Martin Combined Cycle Unit Nos. 5 and 6 into the electric system will not require new off-site transmission lines, however, on-site transmission work will be required.

D. Fuel Delivery Facilities

Natural Gas

An existing Florida Gas Transmission (FGT) mainline runs north and south just west of the Lauderdale Plant Site. The Plant is presently served by a lateral that enters the site at the Southwest corner. A new east-west lateral is planned along the northern boundary of the plant site. This new FGT lateral, which will parallel an existing lateral that serves FPL's Port Everglades Plant, is being installed independently of the Lauderdale Repowering Project to enhance deliverability of natural gas to the existing Lauderdale generating facilities. The new lateral will be sized to accommodate the gas requirements of the repowered units.

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To supply the required amounts of gas to the Martin Combined Cycle Unit Nos. 3 and 4, a new thirty inch diameter lateral will be constructed from the FGT mainline to the plant site. FPL and FGT are jointly performing studies to determine the optimum route for this lateral. The preliminary length estimate for this lateral is eighteen to twenty-three miles. The length of the lateral is subject to change once the final routing is determined.

Coal

The Martin Plant site is currently served by a six mile rail spur from the main line of the Florida East Coast Railway. In order to provide the flexibility of having two alternative means of coal delivery (and the resulting competitive coal transportation costs), a rail spur approximately one mile in length would need to be constructed from the existing CSX Railroad main line, which runs adjacent to the plant site.

E. Future Gasifier

As discussed above, the Martin Combined Cycle Unit Nos. 3 and 4, which will be fired on natural gas, are capable of conversion to use coal gas if and when future fuel price and/or availability conditions warrant addition of a coal gasifier (the "future gasifier"). FPL does not have current plans to add the future gasifier at a specific date. Nevertheless, FPL is planning to present the expected environmental impacts of the future gasifier as part of the site certification application for the Martin Expansion Project, in order to obtain the maximum environmental licensing that can be achieved for such a facility at this time.

F. Financial Information

FPL has determined that it has the financial capability to complete the Lauderdale Repowering Project and the Martin Expansion Project, using a combination of internally and externally generated funds. FPL is currently evaluating various options to determine the best method for financing, constructing and operating each of the new units. Options under consideration include conventional financing using a capital structure that reflects the long term capitalization objectives of the company; use of a turnkey construction contract under which some of the risks for construction financing can be shared with a third party construction contractor; and a third party financing and operating option in which a third party would contract to construct, own and operate all or part of a unit and sell the output of the completed unit to FPL. It is possible that some combination of these options will be used, with different financing approaches for different units.

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VI. CONSEQUENCES OF DELAY

A. Delay Of In-Service Date

The schedule of unit additions presented in this document was developed to meet system reliability requirements in a cost effective, strategically sound manner. Delay of the in-service dates of any of the units may have detrimental effects on system reliability. The impact on system reliability is summarized in Table VI.A.1. The summary shows that a one year delay of any of the units will result in a net system LOLP greater than 0.1 days/year, the maximum acceptable level.

Impact Of One Year Delay Of In-Service Dates Of Proposed Units

Unit	In-Service Year	LOLP Net Day/Year No Delay	LOLP Net Day/Year 1 Year Delay
Repower Lauderdale 4, 5	1993	.0403	.2533
Martin Combined Cycle 3	1994	.0737	.1962
Martin Combined Cycle 4	1995	.1615	.4053
Martin Combined Cycle 5,6	1996	.0409	.2318

Table VI.A.1

B. Delay In Licensing

The impact of delays in licensing on the in-service dates of new generating capacity depends on the licensing and construction lead times required to meet the proposed in-service dates. Table VI.A.2 shows the time frames generally required to complete state and federal licensing and to construct new units. These time frames are based on actual licensing experience and a combination of actual construction experience and best engineering judgment. The time frames shown for licensing are measured from the submission of a Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act. They do not include the time required for site evaluation, data collection and preparation of the license applications. Table VI.A.2 also shows, based on these time frames, the times by which FPSC need certification actions must normally be completed in order to avoid delaying the overall licensing process.

Lead Times And Licensing Schedules

Capacity Addition	Latest SCA Filing[1]	Latest Need Decision[2]	Licensing Complete	Construction Period	In-Service Date
Lauderdale Repowering	12/89	5/90	2/91	22 Months	12/92
Martin CC No. 3	2/90	7/90	8/91	28 Months	12/93
Martin CC No. 4	2/91	7/91	8/92	28 Months	12/94
Martin IGCC Nos. 5 & 6	9/91	2/92	3/93	33 Months	12/95

[1] Fourteen to eighteen months prior to final issuance of state and federal permits.
[2] Five months after filing of SCA.

Figure VI.A.2

As reflected in the preceding table, it is theoretically possible to separate the licensing of the various units that comprise the Martin Expansion Project. However, in order to properly evaluate and fully address the environmental impacts of constructing both combined cycle capacity and coal gasification facilities at the existing Martin Site, it is highly desirable and cost effective, from both regulatory agency and utility perspectives, to combine them into a single environmental licensing effort.

Given the lead times presented above, if the Martin licensing efforts were separated, the agency review of the application for Martin Unit No. 4 would have to begin approximately six months before the licensing for Martin Unit No. 3 was complete. Similarly, the licensing for the IGCC Units would have to begin almost a year before licensing of Martin Unit No. 4 was complete. Moreover, due to different licensing and construction lead times, the Site Certification Applications for the Lauderdale Repowering and the Martin Combined Cycle Unit No. 3 have to be filed no more than three months apart despite the one year difference in their projected in-service dates. This would require almost simultaneous action by the FPSC on the need petitions for these units.

In light of these licensing schedule considerations and other factors, FPL has elected to address the Lauderdale Repowering and the full Martin Expansion Project in a single need determination presentation. This unified presentation has the following advantages:

1. First, the presentation is consistent with FPL's internal planning process. By evaluating competing streams of unit additions over a multi-year planning horizon, both FPL and the FPSC can properly consider both longer lead time units and larger units that incorporate economies of scale.

2. Second, FPL has a capacity need in 1993 and each of the four following years. Because the later units identified by FPL have longer lead times than the earlier units, a single certification proceeding results in a more efficient use of FPL's and the FPSC's resources than a series of several separate but interrelated proceedings in a fairly short time period.

3. Third, as noted above, the simultaneous licensing of multiple unit additions at the Martin site will enable FPL to present a comprehensive evaluation of expected environmental impacts to the FDER and other environmental licensing authorities.

A comprehensive licensing evaluation will enable FPL to engage in coordinated site planning and facilities design while minimizing the potential conflicts which could arise from several separate licensing proceedings for generating facilities at the same site.

4. Finally, completing the licensing of the Martin units in advance of the latest possible date enhances FPL's flexibility to adjust the timing of those units, or to consider phased construction of the combustion turbine portions of those units, if unexpected increases in demand or unexpected decreases in supply side resources, such as QFs, threaten FPL's system reliability earlier than currently predicted.

VII. CONCLUSION

The base generation expansion plan developed by FPL is a cost effective, flexible approach to meeting the needs of future customers. Of the over 5,000 MW of incremental need identified by the year 1997 to maintain system reliability, over 3,000 MW will be met by conservation, load management, interruptible load, qualifying facilities and power purchases. The remaining 2,000 MW will be met by capacity additions based on advanced coal capable combined cycle technology. This technology will allow FPL to respond to the changing environment certain to be experienced in the future. By building new capacity capable of utilizing coal gasification as a potential fuel source, the new units will allow FPL to defer capital expenditures while maintaining the coal option.

Power Supply Expansion Plan

Total Installed Cost ($/KW)	Year	Addition	Summer Net
		Lauderdale Repowering Project[1]	
818	1993	Repower Lauderdale No. 4	286 MW
		Repower Lauderdale No. 5	286 MW
		Martin Expansion Project[1]	
821	1994	Martin Combined Cycle No. 3	385 MW
821	1995	Martin Combined Cycle No. 4	385 MW
2,229	1996	Integrated Coal Gasification Combined Cycle (ICCC) Plant consisting of:	
		Martin Combined Cycle No. 5	384 MW
		Martin Combined Cycle No. 6	384 MW
		Total	2,110 MW

Notes:

[1] The Martin Combined Cycle units and the repowered Lauderdale Units are all 400 MW class units. Because FPL's planning is based on its need to meet summer peak demand, all analysis is based on the expected summer net ratings of the proposed units. Actual summer net ratings may vary based on final design and performance testing.

Table VII.1

The final plan, consisting of demand side alternatives and supply side options, represents significant savings over a plan based on new construction alone. FPL has pursued non-construction alternatives, as stated above, to meet 60% of its future needs. The remaining needs through 1997 must be met by new capacity additions, as shown in Table VII.1.

It is this schedule of new capacity additions for which FPL seeks FPSC approval.

APPENDICES

Appendices

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Appendix A
Generating Facilities And Interconnections

List of Abbreviations
Used In Tables A.1 And A.2

Reference	Abbreviation	Definition
Unit Type	N	Nuclear
	FS	Fossil Steam
	D	Diesel
	CT	Combustion Turbine
	CC	Combined Cycle
	C	Coal Fired

Reference	Abbreviation	Definition
Fuel Type	N	Nuclear
	NG	Natural Gas
	HO	Heavy Oil (#4, #5 & #6)
	LO	Light Oil (#1, #2 or Kerosene)
	C	Coal
	No	None

Reference	Abbreviation	Definition
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	B	Barge
	S	Ship
	No	None
	Unk	Unknown

Table A.1
(Page 1 Of 4)

FLORIDA POWER & LIGHT COMPANY
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1988

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Commercial In-Service Month/Year	(8) Expected Retirement Month/Year	(9) Gen. Max. Nameplate KW	(10) Net Capability Summer MW	(11) Net Capability Winter MW	(12) Fuel Transport Pri.	(13) Fuel Transport Alt.
Turkey Point		Dade County 27/57S/40E						2,337,790	2,080.0	2,130.0		
	1		FS	NG	HO	4/67	Unknown	402,050	367.0	370.0	PL	WA
	2		FS	NG	HO	4/68	Unknown	402,050	367.0	370.0	PL	WA
	3		N	N	No	12/72	Unknown	759,970	666.0	688.0	TK	No
	4		N	N	No	9/73	Unknown	759,970	666.0	688.0	TK	No
	1-5		D	LO	No	4/68	Unknown	13,750	14.0	14.0	TK	No
Lauderdale		Broward County 30/50S/42E						1,133,972	1,126.0	1,248.0		
	4		FS	NG	HO	9/57	Unknown	156,250	137.0	138.0	PL	TK
	5		FS	NG	HO	4/58	Unknown	156,250	137.0	138.0	PL	TK
	1-12		CT	NG	LO	8/70	Unknown	410,736	426.0	486.0	PL	PL
	13-24		CT	NG	LO	8/72	Unknown	410,736	426.0	486.0	PL	PL
Port Everglades		City of Hollywood 23/50S/42E						1,679,086	1,582.0	1,648.0		
	1		FS	NG	HO	6/60	Unknown	225,250	204.0	205.0	PL	WA
	2		FS	NG	HO	4/61	Unknown	225,250	204.0	205.0	PL	WA
	3		FS	NG	HO	7/64	Unknown	402,050	367.0	369.0	PL	WA
	4		FS	NG	HO	4/65	Unknown	402,050	367.0	369.0	PL	WA
	1-12		CT	NG	LO	8/71	Unknown	410,736	426.0	486.0	PL	WA
	1-5		D	LO	No	4/68	Unknown	13,750	14.0	14.0	PL	WA

Table A.1
(Page 2 Of 4)

FLORIDA POWER & LIGHT COMPANY
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1988 (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Fuel		Commercial	Expected	Gen.Max.	Net Capability		Fuel Transport	
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	In-Service Month/Year	Retirement Month/Year	Nameplate KW	Summer MW	Winter MW	Pri.	Alt.
Riviera		City of Riviera Beach 33/42S/43E						620,840	544.0	548.0		
	3		FS	NG	HO	6/62	Unknown	310,420	272.0	274.0	PL	WA
	4		FS	NG	HO	3/63	Unknown	310,420	272.0	274.0	PL	WA
Martin		Martin County 29/39S/38E						1,726,600	1,566.0	1,580.0		
	1		FS	HO	NG	12/80	Unknown	863,300	783.0	790.0	PL	PL
	2		FS	HO	NG	6/81	Unknown	863,300	783.0	790.0	PL	PL
St. Lucie		St. Lucie County 16/36S/41E						1,700,000	1,553.0	1,579.0		
	1		N	N	No	12/76	Unknown	850,000	839.0	853.0	TK	No
	2 1/		N	N	No	8/83	Unknown	850,000	714.0	726.0	TK	No
Cape Canaveral		Brevard County 19/24S/36E						804,100	734.0	740.0		
	1		FS	NG	HO	4/65	Unknown	402,050	367.0	370.0	PL	WA
	2		FS	NG	HO	5/69	Unknown	402,050	367.0	370.0	PL	WA
Sanford		Volusia County 16/19S/30E						1,028,450	861.0	871.0		
	3		FS	NG	HO	5/59	Unknown	156,250	137.0	139.0	PL	WA
	4		FS	HO	No	7/72	Unknown	436,100	362.0	366.0	WA	No
	5		FS	HO	No	6/73	Unknown	436,100	362.0	366.0	WA	No

1/ Total capability is 839/853 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.

FLORIDA POWER & LIGHT COMPANY
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1988 (Cont.)

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Commercial In-Service Month/Year	(8) Expected Retirement Month/Year	(9) Gen.Max. Nameplate KW	(10) Net Capability Summer MW	(11) Net Capability Winter MW	(12) Fuel Transport Pri.	(13) Fuel Transport Alt.
Putnam		Putnam County 16/10S/27E						580,000	448.0	468.0		
	1		CC	NG	LO	4/78	Unknown	290,000	224.0	234.0	PL	WA
	2		CC	NG	LO	8/77	Unknown	290,000	224.0	234.0	PL	WA
Ft. Myers		Lee County 35/43S/25E						1,302,300	1,122.0	1,264.0		
	1		FS	HO	No	11/58	Unknown	156,250	137.0	138.0	WA	No
	2		FS	HO	No	7/69	Unknown	402,050	367.0	370.0	WA	No
	1-12		CT	LO	No	5/74	Unknown	744,000	618.0	756.0	WA	No
Manatee		Manatee County 18/33S/20E						1,726,600	1,566.0	1,580.0		
	1		FS	HO	No	10/76	Unknown	863,300	783.0	790.0	PL	No
	2		FS	HO	No	12/77	Unknown	863,300	783.0	790.0	PL	No
St. Johns River Power Park		Duval County 12/15/28E (RPC4)						1,359,201	250.0	250.0		
	1 2/		C	C	No	3/87	Unknown	679,600	125.0	125.0	RR	No
	2 2/		C	C	No	5/88	Unknown	679,600	125.0	125.0	RR	No
Cutler		Dade County 24/55S/40E						236,500	197.0	199.0		
	5		FS	NG	HO	11/54	Unknown	75,000	67.0	68.0	PL	B
	6/		FS	NG	HO	7/55	Unknown	161,500	130.0	131.0	PL	B
						TOTAL SYSTEM AS OF DECEMBER 31,1988 =			13,629.0	14,105.0		

2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1, excluding Jacksonville Electric Authority (JEA) share of 80%.

Table A.1
(Page 4 of 4)

FLORIDA POWER & LIGHT COMPANY
EXISTING GENERATING FACILITIES ON LONG-TERM RESERVE SHUTDOWN (LTRS)
AS OF DECEMBER 31, 1988

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Commercial In-Service Month/Year	(8) Expected Retirement Month/Year	(9) Gen.Max. Nameplate KW	(10) Net Capability Summer MW	(11) Net Capability Winter MW	(12) Fuel Transport Pri.	(13) Fuel Transport Alt.
Riviera		City of Riviera Beach 33/42S/43E						75,000	69.0	71.0		
	2 3/		FS	NG	HO	11/53	Unknown	75,000	69.0	71.0	PL	S
		TOTAL CAPACITY ON LONG-TERM RESERVE SHUTDOWN AS OF DECEMBER 31,1988 =							69.0	71.0		

3/ Riviera Unit No. 2 (Total Combined Capacity of 69/71 MW is currently on Long Term Reserve Shutdown (LTRS).

Table A.2
(Page 1 Of 1)

FLORIDA POWER & LIGHT COMPANY
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES 1/

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel					Net Capability		Fuel Transport.		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Const. Start Mo./Yr.	Commercial In-Service Mo./Yr.	Gen. Max. Nameplate KW	Summer MW	Winter MW	Pri.	Alt.	Status
Lauderdale		Broward County 30/50S/42E						948,000	846.0	898.0			
	4		CC	NG	LO	1990	1993	474,000	423.0	449.0	PL	Unk	P 2/
	5		CC	NG	LO	1990	1993	474,000	423.0	449.0	PL	Unk	P
Martin Combined Cycle Units		Martin County 29/39S/38E						880,000	770.0	856.0			
	3		CC	NG	LO	1990	1994	440,000	385.0	428.0	PL	Unk	P
	4		CC	NG	LO	1991	1995	440,000	385.0	428.0	PL	Unk	P
Martin Integrated Coal Gasification Combined Cycle								880,000	768.0	845.0			
	5	Martin County 29/39S/38E	CC	C	NG	1990	1996	440,000	384.0	422.5	RR	Unk	P
	6	29/39S/38E	CC	C	NG	1990	1996	440,000	384.0	422.5	RR	Unk	P
Riviera		City of Riviera Beach 33/42S/43E						75,000	69.0	71.0			
	2		FS	NG	HO	-----	1993	75,000	69.0	71.0	PL	S	S

1/ Includes only those facilities which are subject to certification under the Florida Electrical Power Plant Siting Act which are projected to be in service during the Site Plan reporting period by 1997.

2/ The ratings shown for Lauderdale Units 4&5 represent the total capacity after repowering and conversion to combined cycle.

List Of FPL Major Interconnections (230 KV And 500 KV)

FPL	FPC[2/]	KV
Poinsett	Holopaw	230
Sanford Plant	North Longwood	230

FPL	TECO[2/]	KV
Johnson	Big Bend	230
Manatee	Big Bend	230
Manatee	Ruskin	230

FPL	JEA[2/]	KV
Duval	Normandy	230
Duval	Normandy	230

FPL	OUC[2/]	KV
Cape Canaveral	Indian River	230

FPL	GRU[2/]	KV
Bradford[1/]	Deerhaven	138

FPL	SECI[2/]	KV
Charlotte	Calusa	230
Ft. Myers	Calusa	230
Rice	Seminole Plant	230
Putnam[3/]	Seminole Plant	230
Titanium[3/]	Seminole Plant	230
Duval	Black Creek	230

Table A.3

List Of FPL Major Interconnections
(230 KV And 500 KV)

FPL	FMPA[2]	KV
Orangedale	Sampson	230
Titanium	Greencove	230

FPL	SOCO[2]	KV
Duval	Hatch	500
Duval	Thalman	500
Yulee	Kingsland	230

Notes:

[1] FPL is interconnected with GRU by one 138 KV transmission line, therefore, it is shown on this table.

[2]
FPC: Florida Power Corporation
TECO: Tampa Electric Company
JEA: Jacksonville Electric Authority
OUC: Orlando Utilities Commission
GRU: Gainesville Regional Utilities
SECI: Seminole Electric Cooperative, Inc.
FMPA: Florida Municipal Power Authority
SOCO: Southern Companies

[3] Bus tie breaker at Seminole Plant normally open, thereby creating Putnam-Titanium 230 KV line.

Table A.3, Continued

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Appendix B
Load And Customer Forecasting Methodology

FLORIDA POWER & LIGHT COMPANY

ECONOMIC, POPULATION, CUSTOMERS, SALES AND PEAKS FORECASTING METHODOLOGY

1989

RESEARCH, ECONOMICS, AND FORECASTING DEPARTMENT

ECONOMICS AND LOAD FORECASTING SECTION

FLORIDA POWER & LIGHT COMPANY

ECONOMIC, POPULATION, CUSTOMERS, SALES AND PEAKS

FORECASTING METHODOLOGY

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FLORIDA POWER & LIGHT COMPANY

ECONOMIC, POPULATION, CUSTOMERS, SALES AND PEAKS

FORECASTING METHODOLOGY

INTRODUCTION

The Economic and Load Forecasting Section of the Research, Economics and Forecasting Department (REF) is responsible for producing the following official forecasts for the Company :

a. Short and long-term economic forecast at the state and national levels.

b. Long-term population forecast for the state, FPL service territory, FPL division, and counties.

c. Short and long-term customer forecasts by revenue class at system level.

d. Short and long-term sales by revenue class at system level.

e. Short-term sales and customer forecasts at division level.

f. Short and long-term Net Energy for Load (NEL) at the system level.

g. Long-term peak forecast at system and division levels.

h. Monthly forecast of NEL and peak for the entire long-term forecasting period.

i. Load shapes and load duration curve forecasts.

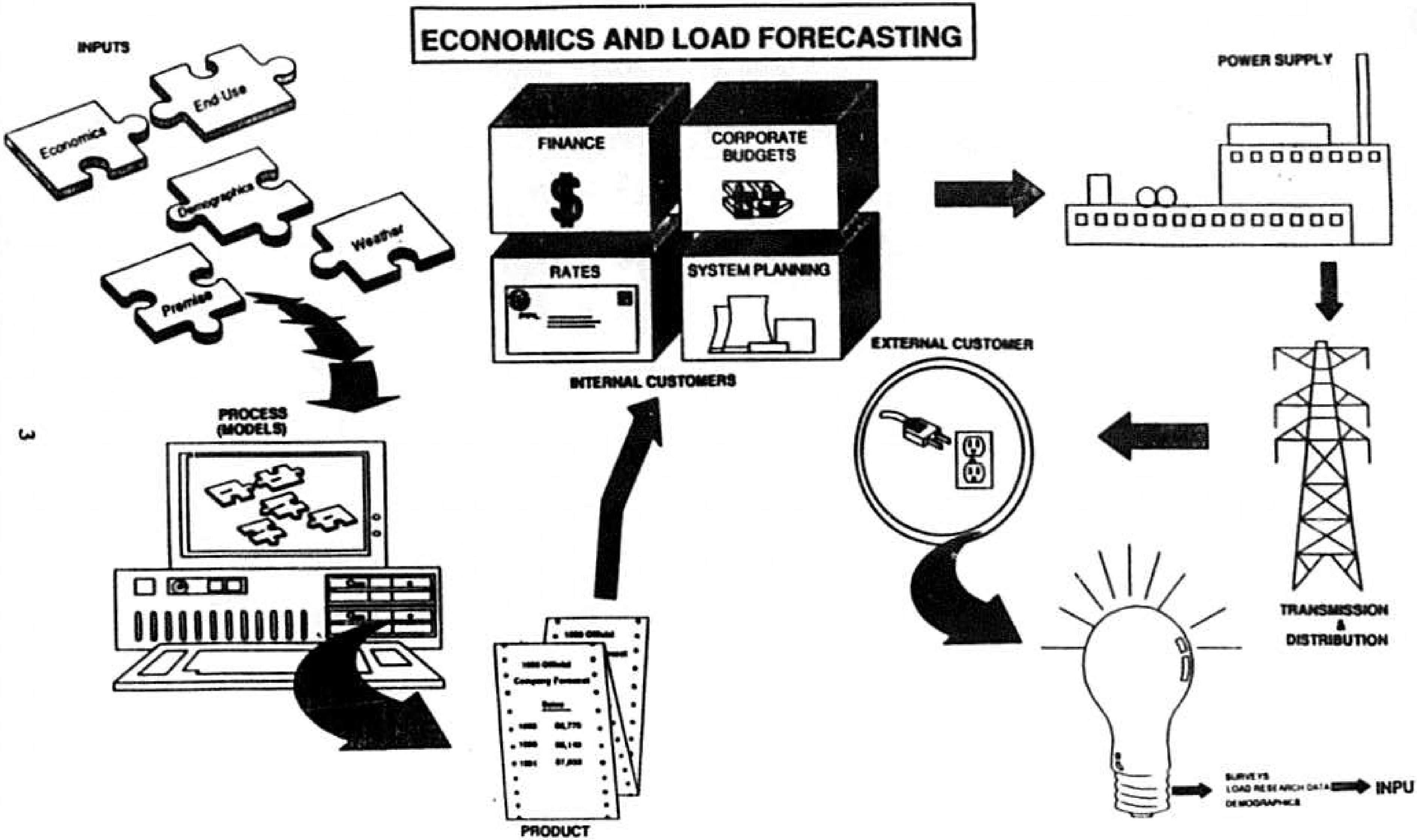
j. Electric end-use market penetration and utilization.

The short-term forecasts are developed on a monthly basis for a period of four years and long-term forecasts are annual for a twenty-year period.

These forecasts are developed once a year and the aggregated forecasts are approved by the Company's Forecast Review Board. These official forecasts are then compiled in the department's forecast publication <u>Economics, Customer and Load Forecasts</u> which is known as the "**Greenbook**". An overall schematic diagram of the forecasting process is shown on page 3.

Because of the complexity of the forecasting process, it is necessary to document and explain how the forecasts are developed. This methodology book , however, is not intended to document every step involved in the forecasting process, but rather provide a general description of methods and techniques utilized. A typical process involved in the short-term and long-term forecasts is shown on page one in the appendix.

The techniques used to develop the short-term forecasts are presented in Chapter I. Chapter II presents the methods used for the long-term forecasts. Due to its complexity, the forecast for the resale revenue class is discussed separately in Chapter III. Chapter IV presents the methodology for the development of high and low-band forecasts, weather data inputs, and the treatment of demand-side programs.


ECONOMICS AND LOAD FORECASTING
INPUTS
End-Use
Economics
Demographics
Weather
Premise
PROCESS
(MODELS)
FINANCE
CORPORATE
BUDGETS
RATES
SYSTEM PLANNING
INTERNAL CUSTOMERS
PRODUCT
POWER SUPPLY
EXTERNAL CUSTOMER
TRANSMISSION
&
DISTRIBUTION
INPU

CHAPTER I

SHORT-TERM

FORECASTING METHODOLOGY

FOR CUSTOMERS, NEL, SALES, AND PEAKS

CHAPTER I

SHORT-TERM FORECASTING METHODOLOGY FOR CUSTOMERS, NEL, SALES, AND PEAKS

THE SCOPE

Short-term forecasts are developed on a monthly basis for the period 1988-1992 for Economics, Customers, Net Energy for Load (NEL), Sales, and Peaks. Short-term forecasts for Economic variables are developed at the State level. NEL, peaks, sales and customers (by revenue class) are developed at the system level. In addition, short-term sales and customer forecasts are also developed at the division level.

DATA SOURCES

Historical monthly data for economics, customer, NEL, sales, and peaks are available from the department data base for the period beginning January, 1963. REF's economic data base, however, consists mostly of economic variables at national and state levels; no regional nor division data are available in usable format.

MONTHLY CUSTOMER FORECAST

The monthly customer forecast is developed for the system, by revenue class, and total customers by division.

General Approach

The State Space forecasting method of time series is applied to develop the short-term customer forecast. The State Space method uses new theoretical techniques, thereby eliminating the need for complex user interaction and subjective judgments commonly required with other methods to determine the model structure and fit.

The key theoretical concept used in State Space forecasts is the "State Vector." On an intuitive level, the State Vector of a system is made up of all the information in that system, both past and present, necessary to describe present and future behavior. Once the State Vector is known and a model is determined for how it evolves in time, forecasts for all future values of the series are easily obtained.

Model Development

To develop short-term customer forecasting models the following steps were taken:

1. Develop one set of State Space models for each of the following revenue classes: residential, commercial, industrial and other authority customers.

   The forecasts for street and highway customers and railroad and railways customers are provided by the Rate Department. The resale customer forecast is developed separately using a different method, which will be discussed in Chapter III.

2. Select models with the best statistics to represent each revenue class.

3. From the selected set of models, generate one set of monthly forecasts for each revenue class for the period of 1989-1992.

4. From each set of forecasts, select only one single model which produces the most acceptable forecast. The logic for this selection is production of reliable statistics, and consistency with past history.

The Forecast

1. Monthly forecasts of residential, commercial, industrial, and other customers are thus obtained from the selected short-term models.

2. Because of the nature of time series forecasting, only the first two-year (1989-1990) forecasts from the short-term models are utilized. The annual forecast of the next two years of 1991-1992 is adjusted to the long-term customer forecast, which is developed separately. Time series models can lose their long-term trend by projecting too far out and this trend is best captured from long-term model.

3. The above forecasts are then added to street & highway and metrorail customer forecasts (provided by the Rate Department) and resale customer forecasts (developed separately) to derive the entire short-term customer forecast by revenue class.

MONTHLY NEL FORECAST

Sales vs. Net Energy for Load (NEL)

To forecast monthly sales, one has to take into account forces that have a great influence on sales, such as weather and economic conditions. Monthly sales are based on meter readings taken throughout the month and may include some energy generated and used during the previous month, although the total recorded usage is credited to this month's sales. Due to this accounting method of reporting monthly sales it is very difficult to match economic and weather data corresponding to consumption of electricity by customer for a given period of time. Therefore, monthly NEL is forecasted since it is the electricity generated to meet the customer demand, net of plant use, in a given month. Monthly generation output can be appropriately matched with variables affecting usage. Transmission and distribution conversion losses, company use of electricity, and the interchange account for other differences between net energy for load and energy sales.

Therefore, NEL should be used instead of sales to capture the true impact of weather and other factors affecting monthly sales.

JURISDICTIONAL NEL FORECAST

The short-term NEL forecast is developed for jurisdictional NEL which is defined as system NEL minus resale NEL.

General Approach : The "48-Pool-Hour Model"

Forecasted values for system hourly load for the period 1989-2008 are produced using the new methodology introduced two years ago, referred to as the "48-pool-hour" model. The objective of this approach is to provide statistically reliable and consistent estimates of load for each hour of the 168 unique hours which comprise a week. To accomplish this, the 168 hours are classified as either weekend or weekday hours while keeping their position within the 24-hour cycle. Thus, 48 clusters or "pools" are created (Hour of Day x Weekend/weekday). One set of explanatory variables is developed which could be used to predict the load for any weekday hour, and a similar set of variables is used to predict the load for any weekend hour. In this way, a peak, valley, average load, net energy for load, and load factor can be provided for any period of time during this twenty year period.

General Structural Model

It has been decided that distinguishing between weekends and weekdays would provide more consistent "pools" of data, thus producing more reliable and efficient estimation equations. This weekend/weekday dichotomy is crossed with the position of each hour within the daily cycle, yielding a total of 48 pools. Thus, the 168 unique hours of the week could be statistically condensed into these 48 pools.

After continued exploration and development, one overall set of explanatory variables is selected to estimate system hourly load. The only modification to this set of variables involves additional variables unique to days of the week. This generates, in effect, two sets of explanatory variables, one for weekday hours and the other for weekend hours. Each set of variables corresponds to one-half of the 48 pools, and each one of these 24 estimation equations is mathematically unique because it represents the influence of a different day of the week.

The general form of the structural model is provided below, derived from the statistical procedure of multiple regression:

$$
\begin{aligned}
\mathrm{SYSHRLD}_h = a_0 \; & + \mathrm{RESCUST} * a_1 && + \mathrm{RAVPLAG2} * a_2 \\
& + \mathrm{DCOACTMP} * a_3 && + \mathrm{DCOACTSQ} * a_4 \\
& + \mathrm{DCOACTCU} * a_5 && + \mathrm{DCOACHUM} * a_6 \\
& + \mathrm{DHO} * a_7 && + \mathrm{DHOSHTMP} * a_8 \\
& + \mathrm{DHOSHTSQ} * a_9 && + \mathrm{DHOSHTCU} * a_{10} \\
& + \mathrm{CLBILDUP} * a_{11} && + \mathrm{HTBILDUP} * a_{12} \\
& + \mathrm{SIN2PIWK} * a_{13} && + \mathrm{COS2PIWK} * a_{14} \\
& + \mathrm{SIN4PIWK} * a_{15} && + \mathrm{COS4PIWK} * a_{16} \\
& + \mathrm{DHOLIDAY} * a_{17 \ldots} \\
& + \mathrm{DUMMYSAT} * a_{18}
\end{aligned}
$$

(if hour being estimated occurs during Saturday or Sunday)

or,

$$+ \text{DUMMYMON} \cdot a_{18} \quad + \quad \text{DUMMYTUE} \cdot a_{19}$$

$$+ \text{DUMMYWED} \cdot a_{20} \quad + \quad \text{DUMMYTHU} \cdot a_{21}$$

(if hour being estimated occurs during Monday through Friday)

Where:

SYSHRLD	=	estimated system load for hour **h**,
RESCUST	=	number of residential customers at hour **h**,
RAVPLAG2	=	nominal cents per kWh divided by the Consumer Price Index (real average price of electricity), lagged two months to reflect ratepayer behavioral reactions to costs of consumption at hour **h**,
DCOACTMP	=	the difference between the temperature at hour **h** and a baseline value for temperature, multiplied by a value representing residential customer air conditioning saturation at hour **h**,
DCOACTSQ	=	the same as DCOACTMP, except the temperature and baseline value difference is squared,
DCOACTCU	=	the same as DCOACTMP, except the temperature and baseline value difference is cubed,
DCOACHUM	=	the relative humidity at hour **h**, multiplied by the residential A/C saturation value at hour **h**,
DHO	=	a dummy variable to indicate presence or absence of heating relative to a baseline value of temperature at hour **h**,
DHOSHTMP	=	the difference between a baseline value for temperature at hour **h** and the temperature, multiplied by a value representing residential space heating saturation at hour **h**,
DHOSHTSQ	=	the same as DHOSHTMP, except the baseline value and temperature difference is squared,
DHOSHTCU	=	the same as DHOSHTMP, except the baseline value and temperature difference is cubed,

CLBILDUP = the sum of lags one through four from hour **h**, for the differences between temperature and the baseline value, to represent a "build-up" of heat that requires more cooling,

HTBILDUP = the sum of lags one through four from hour **h**, for the differences between the baseline value and temperature, to represent a "build-up" of cold that requires more heating,

SIN2PIWK
COS2PIWK = a set of four functions to explain cyclical
SIN4PIWK variation during the course of the 52 weeks
COS4PIWK in a year,

DHOLIDAY = a dummy variable indicating whether the day during which hour **h** occurs is a holiday or not,

DUMMYSAT
DUMMYMON five separate dummy variables which
DUMMYTUE = indicate whether hour **h** occurs during the
DUMMYWED day in question or during the other six
DUMMYTHU days of the week.

a_0 = a mathematical constant for the multiple regression model that is unique for each of the 48 equations,

$a_1 ... a_{20}$ = weights given to the explanatory variables as determined by their unique information when statistically combined to estimate system load at hour **h**.

In an attempt to represent the contribution of economic variables to system load, the real average price of electricity lagged two months was added as a predictor. The lag reflects that ratepayers often do not adjust their kWh consumption habits until they have seen recent electricity bills form what they believe is a "trend."

The Forecast

To develop a prediction equation unique to each one of the 48 pools, estimation of the model was performed on system hourly load data for 1983-1988 provided to the Edison Electric Institute (EEI). These six years of data were grouped for the analysis according to their corresponding pools. This was determined by each hourly load's day of the week and position in the sequence of the day's 24 hours.

To use the set of prediction equations developed as explained above, values are needed for number of residential customers, residential air conditioning, space heating saturation projections, and typical weather (temperature and humidity) for the FPL service territory. The projected number of customers are obtained from the REF department. Estimates of air conditioning and space heating saturations by year are obtained from the Electric Power Research Institute's (EPRI) Residential End-Use Energy Planning System (REEPS) and REF's Home Energy Surveys of residential customers.

Typical weather is determined by extensive analysis of the 24 years of data between 1965 and 1988 in terms of temperature, relative humidity, and heating and cooling degree day patterns. Weighted composites of FPL System temperature and relative humidity are statistically derived as "typical" for each of the twelve months of the year. Peak day values for Winter and Summer seasons are also statistically derived and fixed to occur on a Tuesday in the middle of fiscal January and August, respectively. Adjacent hours between "typical months" had their weather values "smoothed" in some cases to produce a more consistent transition.

<u>Assumptions, Definitions and Adjustments</u>

Both temperature and humidity used in the estimation and forecasting of system hourly load represent a weighted composite of FPL's service territory. Data for the Miami, Fort Myers and Daytona Beach weather stations are weighted by their corresponding divisional monthly sales. Miami corresponded to Southern, Southeastern, Eastern Divisions; Fort Myers to Western Division; and Daytona Beach to Northeastern Division. Temperature and humidity data are provided by the National Oceanic and Atmospheric Administration (NOAA) in readings for every third hour. This data is linearly interpolated to produce values for each hour of the day.

Forecasted values for each hour of system load are usually examined on a monthly or yearly basis concerning net energy for load (NEL) and peaks. Naturally, forecasts for 1989-2008 for NEL and peaks as derived by the 48-pool-hour technique will differ from the forecasted values for these quantities as derived for the **Economics, Customer and Load Forecasts** (the "Greenbook"). Hence, the forecasted values from the two approaches must be reconciled.

A load shape modifier routine is used for this purpose. Very simply, it fixes the monthly peak at the value of FPL's official forecast (the Greenbook) and the monthly valley as the value of the 48-pool-hour model. The ratio of the peaks from the two separate forecasts is then used in an iterative process to readjust each hourly value in the 48-pool-hour model until the monthly NEL for this model equals that in FPL's official forecast. This process is executed for each one of the 240 fiscal months in the 20-year forecast period.

MONTHLY SALES FORECAST

Monthly NEL/Sales Ratios

After the forecast of jurisdictional NEL is developed, jurisdictional sales can be derived by applying the monthly NEL/saies ratio forecast.

The ratio of NEL/sales is expected to be greater than one because the amount of energy received by customers has to be less than the amount generated by power plants because of transmission and distribution losses. Due to billing cycle adjustments, the ratio could be less than one for given months. Actual monthly sales are based on meter readings taken throughout the month and may include some energy generated and used during the previous month and a portion of the energy consumed this month maybe credited to next month's bill.

Monthly Jurisdictional and System Sales Forecasts

The following steps are developed to convert the jurisdictional NEL forecast to the jurisdictional sales forecast:

1. Forecast monthly NEL/Sales ratios using the State Space Time Series Forecasting technique.

2. Divide the monthly jurisdictional NEL forecast by the forecast of monthly NEL/Sales ratio to obtain an initial forecast of monthly jurisdictional sales.

3. Calculate **annual** NEL/Sales ratios by dividing the **annual** NEL to **annual** sales forecast from the monthly forecast.

4. Compare the above loss factor forecast with the official loss factor forecast provided by other departments.

5. Adjust the monthly jurisdictional sales forecast in step-two so that the annual jurisdictional NEL/Sales ratios equal the official loss factor forecast.

6. Add resale forecast to jurisdictional sales forecast to generate the monthly total sales forecast for the system.

Monthly Sales Forecast by Revenue Class

The monthly sales forecast is also developed for each revenue class. The monthly sales forecasts for Street & Highway and Railroad and Railways are provided by other departments and the Resales sales forecast is developed separately. Thus, the only revenue classes to be forecasted are Residential, Commercial, Industrial, and Other Authority. The following steps represents the forecasting process used to develop the short-term sales forecast by revenue class.

1. Develop a set of State Space models for Residential, Commercial, Industrial, Other Authority sales using historical sales data from 1/1963.

2. Select models with the best statistics to represent each revenue class.

3. From a selected set of models, generate one set of monthly sales forecasts for Residential, Commercial, Industrial, and Other Authority for the period of 1989-1992.

4. Select only one single model which produces the most acceptable forecast consistent with past history.

5. Generate an initial sales forecast for Residential, Commercial, Industrial, and Other from selected models.

6. Derive a sub-total of sales forecast by summing up sales forecasts of Residential, Commercial, Industrial, and Other.

7. Derive another sub-total by subtracting from system sales forecast, sales forecasts of Resale, Street & Highway, and Railroad and Railways. This sub-total is equivalent to the sum of Residential, Commercial, Industrial, and Other sales forecasts.

8. Adjust the initial forecast of Residential, Commercial, Industrial, and Other sales developed in Step 5, so that sub-total in Step 6 is equal to sub-total in Step 7.

The above forecasts are then added to Street & Highway and Metrorail sales forecasts (provided by Rate Department) and Resale sales forecast (developed separately) to derive the entire short-term sales forecast for each revenue class.

MONTHLY NEL FORECAST

Monthly NEL forecast is also generated for the entire long-term forecasting period of 1993-2008. The following steps are used to produce the monthly NEL forecast.

1. Develop the historical seasonal factor for each month by using ratios of historical monthly NEL to annual NEL.

2. Apply the monthly ratios to the annual NEL forecast to derive the NEL forecast by month. This process assumes the seasonal factor remains unchanged over the forecasting period.

The annual NEL forecast is from the long-term NEL forecast.

MONTHLY PEAK FORECASTS

Monthly peaks for the 1989-2008 period are forecasted to provide information for scheduling maintenance of plants and budgeting fuel. The forecasting process is the same as the monthly NEL forecast.

1. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to annual peak.

2. Apply the monthly ratios to the annual peak forecast to derive the peak forecast by month. This process assumes that the seasonal factor remains unchanged over the forecasting period.

The annual peaks forecast for summer and winter were incorporated in the long-term forecast.

CHAPTER II

LONG-TERM

FORECASTING METHODOLOGY

FOR ECONOMICS, POPULATION, CUSTOMERS, SALES, AND PEAKS

CHAPTER II

LONG-TERM FORECASTING METHODOLOGY FOR ECONOMIC, POPULATION, CUSTOMERS, SALES, AND PEAKS

Annual forecasts of economic, population, customers, sales, net energy, and peaks are developed once a year, for the twenty-year period of 1989-2008.

This chapter describes how these forecasts were developed for each component of the long-term forecast : economic, population, customer, sales and NEL, and peaks.

ECONOMIC FORECAST

The Model

FPL's Economic Forecast is developed using DRI's Macro Model. DRI's Model captures the full simultaneity of the U.S. economy; forecasting 1200 variables related to demand and supply aggregates, prices, incomes, international trade, financial markets, and industrial detail. Within the basic structure of the model is the interaction of the eight sectors :

1)	Domestic Spending	5)	Financial
2)	Domestic Income	6)	Inflation
3)	Tax Policy	7)	Simulate Supply Potential
4)	International	8)	Expectations

Each of these eight sectors has within it a host of simultaneous equations to capture the relationship of various economic activities within the sector and interactions with other sectors.

The Forecast

The economic forecast is developed within the DRI framework, but is adjusted on a as needed basis for consistency with other assumptions within the company. For example, a key factor in the DRI model is Fuel Prices. DRI's forecast has to be adjusted to reflect FPL's official fuel price forecast.

The state level forecasts for the short - run were developed using State-Space. The long-term forecast was developed using DRI's state level forecast. The forecasting process for economics is shown on page 2 in the appendix.

POPULATION AND HOUSEHOLD SIZE FORECASTS

Population Forecast

The Florida population and population in FPL service territory are the two most important components used to forecast the company's long-term customers which is, in turn, used to forecast sales and peak demand.

The forecasts of Florida population and FPL population are based primarily upon the population forecast developed by the Bureau of Economic and Business Research (BEBR) of the University of Florida. While the Florida population forecast can be obtained from computations applied to BEBR's high and mid-band population forecast, the FPL population forecast has to be developed. The reason is that BEBR does not forecast FPL population, per se, but rather provides the population forecast by county. A brief description of the forecasting process can be found on page 3 in the appendix.

FPL Population Estimate for 1988

The department's population data base is updated annually. State and county population estimates for 1988 are provided by the Bureau of Economic and Business Research of the University of Florida. The FPL population estimate for 1988 is derived from BEBR's county population estimate as follows:

a. Identify counties which belong to the FPL service territory. There are 36 counties currently served by FPL.

b. Estimate the percentage of each county's population served by FPL. It is important to note that not everyone living in an FPL served county is necessarily served by FPL. Only those who are, in fact, served by FPL are counted as FPL population.

   The share of each county's population served by FPL is calculated by dividing the number of FPL residential customers in a county by the total residential customers in that county. FPL residential customers by county is available from the FPL data base, and total residential customers by county, including FPL and non-FPL customers, is provided by BEBR.

c. Apply the computed share to BEBR's county mid-band population estimate to derive an FPL county-level population estimate for 1988. This computation assumes that the percentage of residential customers served by FPL in a particular county equals the percentage of the population served by FPL in that county.

d. Add the forecasts of all 36 counties to obtain the estimate for 1988 FPL population.

FPL Population Forecast for 1989 (A One-Year-Ahead Forecast)

FPL's one-year-ahead forecast is based on an econometric analysis of the historical relationship between residential FPL customer counts (based on FPL residential connects through April 1, 1988) and FPL population counts (based on BEBR population estimates through April 1, 1988). The extension of the historical relationship to the 1989 forecast year is possible because April 1, 1989 FPL residential connect data are available. The 1989 FPL population forecast value is, therefore, generated by applying the growth rate derived from the econometric model to the April 1, 1988 FPL population estimate (see above). Since the one-year-ahead forecast uses the most recent FPL residential connect counts, the forecast for that year improves upon the BEBR forecast based on less timely 1988 FPL residential connect data.

FPL Population Forecast for 1989-2008

Comparisons made between post-1980 BEBR population forecasts and the actual resulting post-1980 BEBR population estimates reveals that BEBR forecasts have typically underprojected state and county populations. For this reason, it is inappropriate to accept the BEBR mid-band projection as producing the "most likely" future FPL population numbers. Instead, a procedure based on averaging BEBR high-band and mid-band projections is used in place of simple reliance on the BEBR mid-band projections. The growth rates taken from the average of the BEBR high and mid-bands are applied to the 1989 forecast FPL population (see above) to produce the long-term FPL forecast values for the 1989-2008 period.

Household Size Forecast for 1988-2008

FPL household size is used (along with FPL population-see above) to forecast residential customers, as there exists an identity between FPL residential customers, FPL population, and FPL household size.

Residential customers are the number of residential electric connects and FPL household size is the ratio of FPL population to the number of active FPL residential connects. Household size is merely population-per-residential-customer. The household size defined here is slightly different from the concept of household size commonly used by the public or by the U.S. Census Bureau, where household size is referred to as the average number of persons per household. Indeed, residential customers are not identical to households because FPL residential accounts include some non-households (eg. unoccupied dwellings, real estate development model homes, and condominium house accounts). Because of this difference in definitions, FPL household size is lower than the values of household size estimated by the U.S. Census Bureau or through FPL surveys. In 1986, for example, the value of household size for FPL was 2.23 compared with an estimate of 2.43 for persons per household from the 1986 Home Energy Survey.

The forecast of FPL residential household size is developed by applying the trend in household size taken from the latest U.S. Census Bureau projection for the 1985-2000 period to the actual 1988 FPL residential household size number. It is assumed that the FPL household size projected trend conforms with the national projected trend in household size. According to BEBR, this has certainly been the case for the post-1970 period.

LONG-TERM CUSTOMER FORECAST

The long-term customer forecast is developed for seven revenue classes:

1. Residential
2. Commercial
3. Industrial
4. Street and Highway Lighting
5. Other public authority
6. Railroads and Railways
7. Resale

An overall description of the long-term customer forecasting process is shown on page 4 in the appendix.

The Model

The forecasts of Street and Highway customers and Railroad and Railways customers are provided by the Rate Department. The resale customer forecast is developed separately using a different method discussed in Chapter III.

Residential Customers

An econometric model is developed to forecast residential customer using FPL population and household size as independent variables. The model is shown below.

LONG-TERM RESIDENTIAL CUSTOMER MODEL

DEPENDENT VARIABLE : LRESCUS

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
LHHSIZE	-1.001	-1258.03
LFPLPOP	1.00006	21705.87

Adjusted R-Square	=	1.000
Durbin-Watson D-Statistic	=	5.88
F-Ratio	=	7000000.0

Where :

LRESCUS	:	Log of FPL residential customers
FPLPOP	:	Log of FPL Population
HHSIZE	:	Log of FPL household size

The above model is selected and used to forecast the residential customers for the period of 1989-2008.

Commercial Customers

The long-term commercial customer forecast was developed using a double log multiple regression model. The explanatory variables are FPL population and Florida commercial employment.

As the population in FPL's service territory increases, the addition of new commercial establishments in the area also increases. Likewise, commercial employment captures the level of commercial activity. The model is shown below.

LONG-TERM COMMERCIAL CUSTOMERS MODEL

DEPENDENT VARIABLE : LCOMCUS

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-11.6656	-12.24
LFPLPOP	1.4260	16.45
LCOMEMP	0.12234	2.19

Adjusted R-Square	=	0.9985
Durbin-Watson D-Statistic	=	2.0072
F-Ratio	=	3888.4

Where :

LCOMCUS	:	Log of FPL commercial customers.
LFPLPOP	:	Log of FPL population.
LCOMEMP	:	Log of Florida commercial employment.

Industrial Customers

As with commercial customers, a multiple regression model is used to forecast long-term industrial customers. The model is developed using historical data from 1965-1988.

Manufacturing and construction are the two dominating activities in industrial customer class, and are highly sensitive to the economic cycle. Furthermore, many industrial customers produce goods which are sold nationwide. Consequently, the growth of customers in this revenue class has been highly influenced by the national economy's performance. For this reason, Real Gross National Product (RGNP) is used as an explanatory variable. In addition, a dummy variable is used to reflect reclassification of Industrial customers in 1975.

LONG-TERM INDUSTRIAL CUSTOMERS MODEL

DEPENDENT VARIABLE : LINDCUS

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-5.3394	-3.65
LRGNP	1.7762	9.49
POST75	0.5076	8.29

Adjusted R-Square	=	0.9773
Durbin-Watson D-Statistic	=	1.8503
F-Ratio	=	317.51

Where :

LINDCUS	=	Log of FPL industrial customers.
LRGNP	=	Log of real GNP.
POST75	=	A Dummy variable used to reflect reclassification of industrial customers since 1975.

Street & Highway Lighting Customers

Street and Highway customer forecast for the period of 1989-2008 was provided by the Rate Department.

Other Public Authority Customers

Establishments such as sports fields, sports coliseums, and military bases, which are owned or operated by municipalities or agencies of federal or state governments, are included in the other public authority revenue class. One rate class included in this revenue class has been closed by the Public Service Commission. The forecast of other public authority customers is developed using specific knowledge regarding the net additions expected in this classification.

Railroad and Railway Customers

This classification is made up of accounts for Dade County's Metrorail transit system and the forecast is provided by the Rate Department.

Resale Customers

The forecast of Resale customers will be discussed separately in Chapter III.

The Forecast

The above models are selected based not only on their statistics, but also on their ability to produce a forecast which is consistent with past history. The final long-term customer forecasts are derived as follows.

1. Obtain the annual forecast of residential, commercial, industrial, and other customers from the long-term forecasting models.

2. Adjust the first two-years (1989-1990) of the forecast to the short-term forecast, which are developed separately.

3. Add to the above forecasts, the forecasts of Street & Highway and Metrorail customer (provided by Rate Department) and Resale customer (developed separately).

LONG-TERM SALES AND NEL FORECASTS

Long-term forecasts of electricity sales are developed for each revenue class for the forecasting period of 1989-2008. Both end-use models and econometric techniques are employed to produce the forecasts. A flow-chart describing the forecasting process is shown on page 5 of the appendix. The methodology used to develop sales forecasts for each jurisdictional revenue class is outlined below.

Residential Sales

The residential sales forecast is developed using the Residential End-Use Energy Planning Model (REEPS). REEPS is an integrated end-use/econometric forecasting model developed by EPRI.

The Model

REEPS forecasts electricity sales by disaggregating the residential sector down to the household level in order to simulate acquisitions and energy usage of nine major residential appliances (space heater, central air-conditioner, room air-conditioner, water heater, range, first refrigerator, second refrigerator, freezer, and dishwasher, plus residual electricity use).

Using a sample of households representative of the full residential customer population, probabilistic choice models are used to determine the stock of appliances in each dwelling based on household characteristics, prices, and other factors. Efficiency and usage equations determine energy consumptions of each appliance. Electricity consumption is aggregated across all households to produce total residential sales.

For the base year, appliance saturations and electricity sales are calibrated to actuals. REEPS then simulates the additions of new appliance stock in new homes and changes in appliance stock in existing homes for ten two-year periods to produce a twenty-year forecast. For each two-year forecast period, forecasts of household characteristics, energy prices, weather and geographic variables, and conservation policies serve as model inputs to influence trends in appliance stock, efficiency and utilization.

These forecasts are used as explanatory variables in the choice and efficiency equations to determine the saturations and efficiencies of new housing appliance stock along with replacement and new acquisitions of appliances in existing housing. Likewise, usage equations determine energy consumption for the appliance stock in place, based on demographic and price forecasts. For each forecast period, appliance electricity consumption is aggregated across all households to produce a forecast of electricity sales.

In addition to forecasting residential electric sales, REEPS household level results are aggregated to produce other forecasts. These include:

- Total residential energy use from all fuel sources
- Appliance saturations
- Appliance efficiencies (relative to the base year)
- Average electricity/fuel use per appliance

All forecasting results can be broken down by vintage (new and existing homes), fuel type (electricity, natural gas, and oil/propane) and house-type (single family, small and large multi-family, and mobile home).

__Model Input__

For The 1989 Greenbook forecast, REF analysts adapted REEPS version 1.1 to FPL's service territory. The following key inputs were used in FPL's implementation of REEPS:

- FPL household appliances and demographics (1988 Residential Appliance and Demographic Survey)
- Residential customer forecast
- Price forecasts of residential electricity, gas, and oil
- Forecasts of household income, household size, and age of head-of-household
- Weather data for Miami, West Palm Beach, Daytona, and Ft. Myers
- Appliance average electricity use for the base year

Data from FPL's 1988 Resideintial Appliance and Demographic Survey (RADS) and the 1986 Home Energy Survey of Residential Customers (HES) were used to characterize FPL's existing residential customers. Results from the survey provided base-year appliance saturations for the nine REEPS appliances; housing information on square footage and housing type; and demographic information on age of head-of-household, household size, household income, and geographic distribution.

The 20-year residential customer forecast, discussed earlier, was disaggregated into four housing types using ratios for single family detached, single family attached (small), single family attached (large), and mobile homes taken from the 1988 RADS.

Forecasts of residential electric prices are determined using current residential electric rates with growth rates taken from FPL's official forecast of real average price of electricity. Forecasts of residential natural gas and propane prices are created by using the growth rates in FPL's official fuel forecast, for natural gas and oil, respectively.

The existing household income distribution is determined from the 1988 RADS. Growth in household income is determined from the residential customer forecast and FPL economic forecast of Florida real personal income. Base-year household size is determined from the 1988 RADS and is forecasted using the trend from the Greenbook forecast of FPL population per residential customer. The forecast of age of head-of-household is made using 1988 RADS data in conjunction with the Bureau of Census projections.

Summer design dry and wet bulb temperature and winter design dry-bulb temperature came from "Engineering Weather Data," by the Marley Cooling Tower Co. Values for cooling and heating degree days are averages for 1950-1980 from the National Weather Service; these years correspond to the weather data used in developing appliance energy use estimates in the Conditional Demand Study of the 1984 HES.

Estimates of appliance electricity consumption are taken from two recent REF studies: (1) "A Model of Residential Energy Consumption and Appliance Ownership," 6/86, a conditional demand analysis of the 1986 HES, and (2) "Heating & Cooling Study," 6/87, a study of 1986 households metering central HVAC systems.

The Forecast

After REEPS is calibrated to actual 1988 residential sales, the model produces a forecast of residential electricity sales for 1990-2008. Since REEPS forecasts at two-year intervals, exponential interpolation is used to produce an annual sales forecast for 1989-2008. Also, an intercept adjustment is made after three years so that the long-term and short-term forecasts would coincide. A process flow chart of the long term residential forecast is shown on page 6 of the appendix.

Commercial Sales

The commercial end-use model, COMMEND, developed by EPRI, is used to forecast long-term commercial sales.

The Model

COMMEND forecasts commercial energy requirements by disaggregating the commercial sector into building types, end-uses and fuel types and then examining trends in those components.

COMMEND views energy demand as a product of four factors:

- Commercial floor space by building type
- Fuel shares (end-use saturations by fuel type) of each end-use by building type
- Energy utilization index (EUI), a measure of energy use per square foot for each end-use by building type
- Utilization of equipment, relative to the base-year

For each building type, the sum across all end-uses gives sales by building type. Aggregating sales across all building types gives overall commercial sales.

In the base year, adjustments are made to calibrated base-year model results to actual system sales. Commercial sales forecasts are produced through modeling changes in each of the four components:

- Forecasts of floor stock are modeled using employee per square foot relationships.

- Fuel shares are forecast through a fuel choice life-cycle cost microsimulation sub-model.

- Changes in EUIs are determined using engineering and cost information for HVAC equipment and econometric elasticity estimates for other end-uses.

- Changes in equipment utilization, relative to the base year, is modeled using short-run econometric fuel price elasticities.

Model Input

To adapt COMMEND to FPL service territory, estimates were needed of the total floor stock of commercial buildings served by FPL, of saturations of end-uses by fuel type within those buildings, and of EUIs by end-use by building type.

Twelve building types and eight end-uses were used in COMMEND to characterize FPL's commercial sector:

Building Type

1. Office
2. Retail
3. Restaurant
4. Grocery
5. Hotel/Motel
6. Elementary/Secondary School
7. College/Vocational
8. Hospital
9. Other Health
11. Warehouse
12. Refrigerated Warehouse
13. Miscellaneous Commercial

End-use

1. Air-Conditioning
2. Heating
3. Ventilation
4. Water Heating
5. Refrigeration
6. Cooking
7. Lighting
8. Miscellaneous

Base year floor stock was estimated using information from the Dun & Bradstreet and Commercial/Industrial Customer Sector Survey (C/I sector survey). COMMEND models future additions to floor space using employee per square foot relationships. Employment forecasts consistent with forecasts of Florida non-agricultural employment were developed for various industries to forecast changes in floor stock by building type.

End-use saturation data came from FPL's Commercial/Industrial Customer Sector Survey (C/I). Estimates of energy use per square foot (EUIs) for existing end-use systems were also based on the C/I survey. An alternate set of EUI's was used for replacement end-use systems and end-use systems being installed in new buildings.

The Forecast

Base-year sales from the model were calibrated to actual FPL 1988 system commercial sales on a building type basis, using the Rate System to give sales by building type based on SIC codes. A process flow chart of the long term commercial sales forecast is shown on page 7 of the appendix.

Industrial Sales

Industrial sales were forecast using a linear multiple regression model incorporating Florida manufacturing employment and FPL service territory population as explanatory variables.

Since this revenue class consists of manufacturers, employment in this sector was an important indicator of economic activity in the sector, translating into sales for the revenue class. FPL service area population was important, since changes in population affect economic activity in the manufacturing sector, resulting in an impact on Industrial sales. The model is shown as follows.

INDUSTRIAL SALES MODEL

DEPENDENT VARIABLE: INDSAL

INDEPENDENT VARIABLES:	COEFFICIENTS	T RATIO
INTERCEPT	-474.572	-6.326
FPLPOP	0.0003	4.242
FMEMP	5.7610	9.033

R - SQUARE	=	0.994
Durbin-Watson D-Statistic	=	2.354
F-Ratio	=	1232.86

Where:

INDSAL	=	Industrial Sales
FPLPOP	=	Population in FPL's Service Territory
FMEMP	=	Florida Manufacturing Employment

Other Public Authority Sales

Because the Sports Field Service (OS-2) rate class within this customer revenue class has been closed by the Public Service Commission, other public authority electricity sales were expected to increase very little over the long-term horizon. A linear multiple regression model was used to forecast long-term sales for this revenue class. The explanatory variables used were Other Public Authority Customers for the years 1969-1973, Other Public Authority Customers for the years 1974-1985, and three variables for the ratio of Real Florida Total Income to Real Average Price of Electricity: one for years prior to 1968, one for the years 1969-1973, and another for the years 1974-1985. The historical period is broken-up into three sub-periods because of customers reclassification in this revenue class.

OTHER PUBLIC AUTHORITY SALES

DEPENDENT VARIABLE: OTHSAL

INDEPENDENT VARIABLES:	COEFFICIENTS	T RATIO
OTHER2	0.152	19.510
OTHER3	0.722	4.181
RATIO2	0.222	4.789
RATIO3	0.155	4.725

R-Square	=	0.998
Durbin-Watson D-Statistic	=	1.1331
F-Ratio	=	1775.16

Where:

OTHER2 = Other customers for the years 1969 to 1973.

OTHER3 = Other customers for the years 1974 to 1985.

RATIO2 = Real Florida Total Income / Real Average Price of Electricity for the years 1969 to 1973.

RATIO3 = Real Florida Total Income / Real Average Price of Electricity for the years 1974 to 1985.

Street & Highway Sales and Railroad & Railways Sales

The forecasts for these two revenue classes are provided by the Rates Department.

Sales forecasts by revenue class are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, a forecast of annual net energy for load (NEL) is generated by applying an expansion factor.

SYSTEM PEAKS FORECASTS

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, abnormal weather conditions, continued economic growth, changing patterns in customer behavior, and more efficient heating and cooling appliances. The Peak models were developed to capture these behavioral relationships to develop reasonable peak load forecasts. A flowchart describing the forecasting process is shown on page 8 in the appendix.

The forecasting methodology of summer and winter system peaks as well as the division summer peaks are discussed below.

System Summer Peak

This model is a variant of the "48-Pool Hour Model" used to produce the short-term NEL forecast described in Chapter 2. The major difference between the two is the subset of hours used in estimating system summer peak, which was empirically determined to have the greatest and most efficient predictive ability. These includes the hours ending 17 through 19 for Mondays through Thursdays during July and August, with the estimated years 1983-88.

The predictors for this model will, of course, differ from the hourly load model because no space heating is required. The real average price of electricity is included in this model because it was theoretically concluded that price does affect ratepayers' behavior in adjusting their thermostats during summer, a finding which was statistically confirmed. (Price, however, is not included in the winter system peak model because when it is very cold in Florida, especially South Florida, ratepayers require space heating unconditionally.) This variable is lagged two months because there is a latency period during which customers examine their bills before changing their behavior.

It was empirically determined that load is weather-sensitive for these peak hours above 72 degrees Fahrenheit. Other modeling and engineering research established that a build-up of heat (cold) occurs in the walls of buildings which will require additional space cooling (heating). Therefore, a predictor that sums the degree hours (base 72) for the eight hours prior to the current hour was established. The model is:

SUMMER PEAK MODEL

DEPENDENT VARIABLE : SYSHRLD

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
RESCUST	0.005230131	48.986
RAVPLAG2	-35536.94851	-18.332
DCOACTMP	0.00000654004	1.642
DCOACHUM	-0.000012528	-11.632
BLDU8HR	22.49366399	19.966
DHOLIDAY	-832.93897	-6.721
COS2PIWK	890.62530	8.987

R-Square	=	0.861
Durbin-Watson D-Statistic	=	2.082
F-Ratio	=	577.23

Where :

SYSHRLD = System Hourly summer load

RESCUST = Number of residential customers at hour h,

RAVPLAG2 = Lag of 2 months of the real average price of electricity, defined as nominal cents per kWh divided by the Consumer Price Index at hour h.,

DCOACTMP = Dry bulb temperature for hour h minus 72 multiplied by the number of residential customers assumed to be using their electric space cooling,

DCOACHUM =	Relative humidity at hour h multiplied by the number of residential customers assumed to be using their electric space cooling,
BLDUP8HR =	Sum of cooling degree hours (base 72) for the eight hours prior to hour h,
DHOLIDAY =	Dummy variable indicating whether the day during which hour h occurs is a holiday or not,
COS2PIWK =	A mathematical function used to explain cyclical variation that occurs over the course of a year.

System Winter Peak

Like the system summer peak model, this model is a variant of the hourly load model, using a subset of hours from the 8,760 in a year. Empirical investigation revealed that optimal predictability and efficiency of estimators was produced using hours ending 8 and 9 during Tuesdays through Thursdays of January, February and December. Years for estimation were 1983-88.

There is no space cooling in this model. However, this model does share with the hourly load model its use of nonlinear (quadratic and cubic) components of temperature for space heating. Space heating was empirically determined to begin below 68 degrees Fahrenheit, because this is when load becomes weather-sensitive. Also, the extreme cold, relatively speaking, that occurs during a rapid change in temperature in Florida is reflected in this model as the sum of temperatures lagged over the prior 24 hours. The real average price of electricity is not included in this model because during winter peak it has been determined that ratepayers are unconcerned with price and require space heating unconditionally. The model is:

WINTER PEAK

DEPENDENT VARIABLE : SYSHRLD

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
RESCUST	0.004138561	29.434
DHOSHTMP	-0.000037358	-2.945
DHOSHTSQ	0.00000846515	8.513
DHOSHHCU	-0.0000000149933	-7.012
BLDUP2DY	-1.19902930	-12.391
DHOLIDAY	787.00933	-7.105
DUMMYHR9	588.01195	9.995

R-Square = 0.984
Durbin-Watson
D-Statistic = 2.319
F-Ratio = 446.63

Where :

RESCUST	=	Number of residential customers at hour h,
DHOSHTMP	=	Dry bulb temperature subtracted from a base of 68 degrees for hour h, multiplied by the number of residential customers assumed to be using their electric space heating,
DHOSHTSQ	=	Same as DHOSHTMP except the difference between base 68 and temperature is squared,
DHOSHTCU	=	Same as DHOSHTMP except the difference between base 68 and temperature is cubed,
BLDUP1DY	=	Sum of temperatures over the 24 hours prior to hour h to reflect a build-up of cold in the walls of buildings requiring greater space heating,
DHOLIDAY	=	Dummy variable indicating whether hour h occurred on a day which is a holiday or not,
DUMMYHR9	=	Dummy variable representing the one degree of freedom between the two hours ending which comprise the subset of hours used for model estimation.

Division Summer Peak Forecast

While the forecasts of system summer and winter peaks are required for operational planning at the system level, the forecast of division summer peaks is also important for transmission and distribution planning. Therefore, a forecast of division peak coincident with the system summer peak is also developed.

The Model

Five models were developed, one per FPL division, to estimate load coincident with system summer peak. The only predictor common to all five models is division customers, which would be expected to drive load coincident with peak per division. The remaining variables, though not common to each model, are real average price of electricity, saturation of electric space cooling, and a build-up of heat over the eight hours prior to peak hour as measured by the sum of dry bulb division-relevant temperatures. Because the number of observations per model is small (n=21), only two to three predictors can be used safely in a multiple regression framework without the risk of these parameter estimators becoming biased (i.e., statistically unreliable when applied to an independent sample). The models are shown as follows:

SOUTHERN DIVISION PEAK MODEL

DEPENDENT VARIABLE: SDPEAK

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-816.67423	-2.842
DIVCUST	4.70122078	4.920
RAVP	-67.60766759	-1.508
ACSAT	13.40725261	1.300

R-Square	=	0.964
Durbin-Watson D-Statistic	=	2.239
F-Ratio	=	151.94

Where :

SDPEAK	=	Southern Division Summer Peak.
DIVCUST	=	Southern Division Customer
RAVP	=	Real Average Price of Electricity.
ACSAT	=	Saturation of electric space cooling.

SOUTHEASTERN DIVISION PEAK MODEL

DEPENDENT VARIABLE: SEDPEAK

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-775.61559	-2.088
DIVCUST	3.60526757	8.398
RAVP	-76.44459286	-2.206
ACSAT	15.31743430	2.570

R-Square	=	0.9662
Durbin-Watson		
D-Statistic	=	1.321
F-Ratio	=	161.956

Where :

SEDPEAK	=	Southeastern Division Summer Peak.
DIVCUST	=	Southeastern Division Customer.
RAVP	=	Real Average Price of Electricity.
ACSAT	=	Saturation of electric space cooling.

EASTERN DIVISION PEAK MODEL

DEPENDENT VARIABLE: EDPEAK

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	362.86601	3.197
DIVCUST	4.49107772	27.814
RAVP	-92.55501071	-3.895

R-Square	=	0.9875
Durbin-Watson D-Statistic	=	1.051
F-Ratio	=	710.971

Where :

EDPEAK	=	Eastern Division Summer Peak.
DIVCUST	=	Eastern Division Customer.
RAVP	=	Real Average Price of Electricity.

WESTERN DIVISION PEAK MODEL

DEPENDENT VARIABLE: WDPEAK

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-486.90183	-3.839
DIVCUST	2.02970555	4.680
ACSAT	13.98988958	4.638

R-Square	=	0.9692
Durbin-Watson D-Statistic	=	1.845
F-Ratio	=	283.501

Where :

SEDPEAK	=	Western Division Summer Peak.
DIVCUST	=	Western Division Customer.
ACSAT	=	Saturation of electric space cooling.

NORTHEASTERN DIVISION PEAK MODEL

DEPENDENT VARIABLE: NEDPEAK

INDEPENDENT VARIABLES	COEFFICIENTS	T RATIO
INTERCEPT	-1681.76566	-4.319
DIVCUST	4.59832513	13.581
TBLDUP8H	2.02644248	3.540
ACSAT	4.78137795	2.619

R-Square	=	0.9862
Durbin-Watson D-Statistic	=	1.892
F-Ratio	=	406.006

Where :

NEDPEAK	=	Northeastern Division Summer Peak.
DIVCUST	=	Northeastern Division Customer.
TBLDUP8H	=	Sum of Dry Bulb Temperatures for eight hours prior to Peak Hour.
ACSAT	=	Saturation of Electric space cooling.

The Forecast

The forecasts of five division summer peak are then summed to produce a system peak total forecast which differs from the official long-term peak forecast. The difference is attributed to several factors. First, the model structures used to produce the system summer peak and five division summer peaks are different. Second, the data available on a division level are very limited in both scope and periodicity. To compensate for these differences, a final adjustment was made to ensure that the sum of all five division peaks equal the official long-term system summer peak forecast. The division summer peak forecast is then validated by comparing the share of each division's peak forecast to the total system peak with that division's historical share of system peak. The share of each division's peak is also compared against the share of each division's population forecast to the total FPL population.

CHAPTER III

RESALE FORECASTING METHODOLOGY

RESALE FORECASTING METHODOLOGY

THE SCOPE

Resale (Wholesale) Customers are composed primarily of municipalities or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers.

The issue of generating capacity also distinguishes the Resale class. Generating capacity refers to the amount of power generated by Resale customers to meet their own needs. There are three classes of Resale customers: partial requirements (PR), full requirements (FR) and aggregate billing partial requirements service agreement (ABPRSA) customers. Partial requirements customers usually have some generating capacity and buy the balance of their energy requirements from FPL or some other utility. Full requirements customers, on the other hand, have no generating capacity, and therefore rely fully on FPL for their generating needs. The ABPRSA class consists of Seminole Electric Cooperative's points-of-delivery (POD) who receive power from Seminole's own generation. A flowchart describing the forecasting process is shown on page 9 in the appendix.

RESALE CUSTOMER FORECAST

Forecasts of Resale customers are obtained from FPL's Power Supply department (SCA). The basis of these forecasts are contract negotiations and informal discussions with our Resale and potential Resale customers. This forecast includes the assumption that Brighton will terminate their FR agreement in 1990 for the purchase of Wholesale power. By 1992 New Smyrna Beach will have dropped from the PR rate. Through the year 2008, further reductions in the number of customers are expected. No new customers are projected to be added to the Resale class.

RESALE SALES AND PEAK FORECASTS TO SEMINOLE

Seminole's service obligation, which defines the mW level at which Seminole is required to serve their own points-of-delivery, has an important impact on future sales to the Resale class. SCA provided information to REF regarding Seminole's likely service obligation through 1994.

Currently, Seminole's service obligation is 612 mW in 1989 and was projected to grow at an annual rate of 2% for the next two years. This obligation, along with the forecast of Seminole's customers, were the two critical components of FPL's forecast of Seminole's sales. FPL's sales to the ABPRSA class was limited to requirements exceeding Seminole's service obligation.

The Model

After determining the underlying assumptions regarding Seminole's customers and service obligations, a model was created for Seminole's own sales within FPL's service territory, regardless of the source of generation.

A multiple regression model was used which explained the historical variation in Seminole's annual sales as a function of real GNP, FPL's total population, and cooling and heating degree days for Daytona. The health of the national economy affects the local economies served by Seminole, and thus the Company's electric sales. Likewise, a growing population in Florida suggests a rise in the number of households served by the Seminole Cooperative, and therefore an increase in electricity usage. The two weather variables were used to explain changes in sales because of weather variations. With forecasted values of the explanatory variables, the model produced a long-term forecast of Seminole's sales. The model is shown as follows.

RESALE SALES MODEL

DEPENDENT VARIABLE: ABPRSA

INDEPENDENT VARIABLES:	COEFFICIENTS	T RATIO
INTERCEPT	-2,751,953	-24.627
RGNP	598.693	5.194
FPLPOP	0.571	8.166
DCDD	76.231	0.950
DCDD	129.235	2.657

R-Square	=	0.997
Durbin-Watson D-Statistic	=	2.09

Where:

RGNP	=	Real Gross National Product
FPLPOP	=	Population in FPL's service territory
DCDD	=	Cooling Degree Days for Daytona Weather station
DHDD	=	Heating Degree Days for Daytona Weather station

An extrapolation of recent trends was used to forecast Seminole's FR sales from Seminole's total sales. Historic load factors were determined and used to project future demand levels for Seminole's FR class. The Seminole FR customers' share of Seminole's sales was assumed to be fully provided by FPL.

LOAD DURATION CURVE ANALYSIS

Load Duration Curve analysis (LDC) was used to forecast FPL's Resale sales to the ABPRSA class. First, average of 1986 and 1987 hourly loads for the ABPRSA class were used to calculate monthly LDC's. Forecast LDC's for the ABPRSA class are then derived from the actual monthly LDC's. The forecast LDC's were assumed to have the same shapes as the average 1986 and 1987 LDC's for the ABPRSA class. The forecast LDC's were shifted based on the regression model results, to account for the growth forecasted in Seminole's sales.

The area under each forecast LDC represented the ABPRSA customer's sales for the month. The level of Seminole's service obligation was superimposed onto each monthly curve. The area between the LDC and the service obligation was calculated to obtain monthly energy purchases from FPL by the ABPRSA class. A short-term forecast of resale sales to the ABPRSA class was thus obtained.

SEMINOLE FORECAST

For the long-term forecast, Seminole's growth rates were applied to annual ABPRSA class sales. A forecast of FPL's total resale sales to Seminole was obtained by summing FPL's sales to the ABPRSA class and sales to Seminole's FR customers.

RESALE SALES AND PEAK FORECASTS TO NON-SEMINOLE FR CUSTOMERS

A State Space model was developed to forecast monthly non-Seminole FR sales. Presently Clewiston is our only non-Seminole FR customer, therefore, the State Space model developed was based solely on historical data for Clewiston. The model was used to forecast monthly sales for the years 1989-1992 based on historical usage patterns extrapolated into the future. Historical load factors for Clewiston were determined and used to project future demand levels.

CHAPTER IV

SCENARIOS, WEATHER, & CONSERVATION

CHAPTER IV

SCENARIOS, WEATHER, & CONSERVATION

DEVELOPMENT OF SCENARIO FORECASTS

In developing the load forecasts, assumptions were made about the most-likely conditions for the economy, population, customer growth, and weather. There is still a great deal of uncertainty embodied in any forecast due to changes in economic, demographic, technological, and social conditions. Therefore, in addition to the most-likely conditions, alternative scenarios are developed to take into account optimistic and pessimistic assumptions about the inputs used in the forecasts. These alternative scenarios are then used to develop high and low-band forecasts of customers, sales, energy, and peaks.

The low and high-band population forecasts are developed using population bands provided by Bureau of Economic and Business Research of University of Florida (BEBR). The high-band is equivalent to BEBR's high-band. The low band is BEBR's mid -band.

The banded forecasts of economic variables are developed using DRI's pessimistic and optimistic outlook. Using high and low economic and population scenarios, high and low-band forecasts of customers are derived for each revenue class.

Bands for the sales forecasts are produced using the bands from customer and economic forecasts as inputs.

Banded forecasts for peaks are developed using the high and low economic growth and customer forecasts. In addition, an extreme weather peak forecast is produced using the most likely assumptions together with an extreme weather scenario.

DEVELOPMENT OF WEATHER VARIABLES

The Scope

Weather is the most important factor which affects the company's sales and peak demand. Weather variable is used in our forecasting models of short-term sales, long-term residential sales, summer peak, and winter peak.

There are two sets of weather variables developed and used in forecasting models :

1. Cooling and Heating Degree Days are used to forecast short-term NEL.

2. Temperature data is used to forecast summer and winter peaks.

COOLING AND HEATING DEGREE DAYS

Cooling and Heating degree days indices are the two important weather variables incorporated into the short-term sales model. These indices are derived from the temperatures recorded every three hours by weather stations in Miami, Fort Myers, and Daytona Beach.

Cooling Degree Days

Cooling degree day index is defined as the difference between actual temperatures from a base temperature which is set as 72°. The index measures the degree of temperature above 72° when customers start using their air-conditioners. Thus, the higher the number of cooling degree days, the higher the use of electricity. The procedure used to derive cooling degree days index is as follows :

1. Cooling degree days index is first calculated for each station based on readings taken every three hours. This hourly index is set equal to actual temperatures minus a base temperature of 72° (with negative values ignored).

2. The index is then weighted by humidity index. A daily average of cooling degree days index is then estimated for each station. Each station's cooling degree days are then summed by month.

3. Calculate the share of each division sales to total system sales. Each division is assigned a weather station closest to the division territory. For Southern, Southeastern and Eastern Division Miami weather station is used. For Western Division Fort Myers weather station is used and for Northeastern Division Daytona Beach weather station is used.

4. Each weather station's monthly cooling degree days are then weighted by the share of the division sales to produce a cooling degree day index for FPL's service territory.

Heating Degree Days

The procedure for estimating heating degree days is similar to that cooling degree days.

1. A heating degree measure was first calculated for each weather station based on readings taken every three hours. This hourly index was calculated by subtracting actual temperatures from a base temperature of 66° (with negative values ignored).

2. After a daily average is estimated, degree days are summed by month.

3. Similar to cooling degree days, each station's heating degree days are weighted by sales to obtain an index for FPL's service territory.

DEMAND-SIDE PROGRAMS

After being generated, the base sales and peak forecasts discussed in the preceding sections have to be adjusted to reflect changes due to the company's demand and supply programs. These programs result in an increase or decrease in sales and peak demand.

Conservation Programs

FPL currently has programs for five different conservation areas:

1. Commercial/industrial audit program
2. Commercial/industrial customer lighting incentive program
3. Residential customer incentive programs (includes home energy loss prevention, window film treatment, water heating, and residential ceiling insulation programs)
4. Swimming pool pump "timer" program
5. Street light conservation.

Except for the street light conservation program, all of the conservation programs listed above affect energy usage of commercial or residential customers. Impact of these conservation programs are subtracted from the Base Forecast.

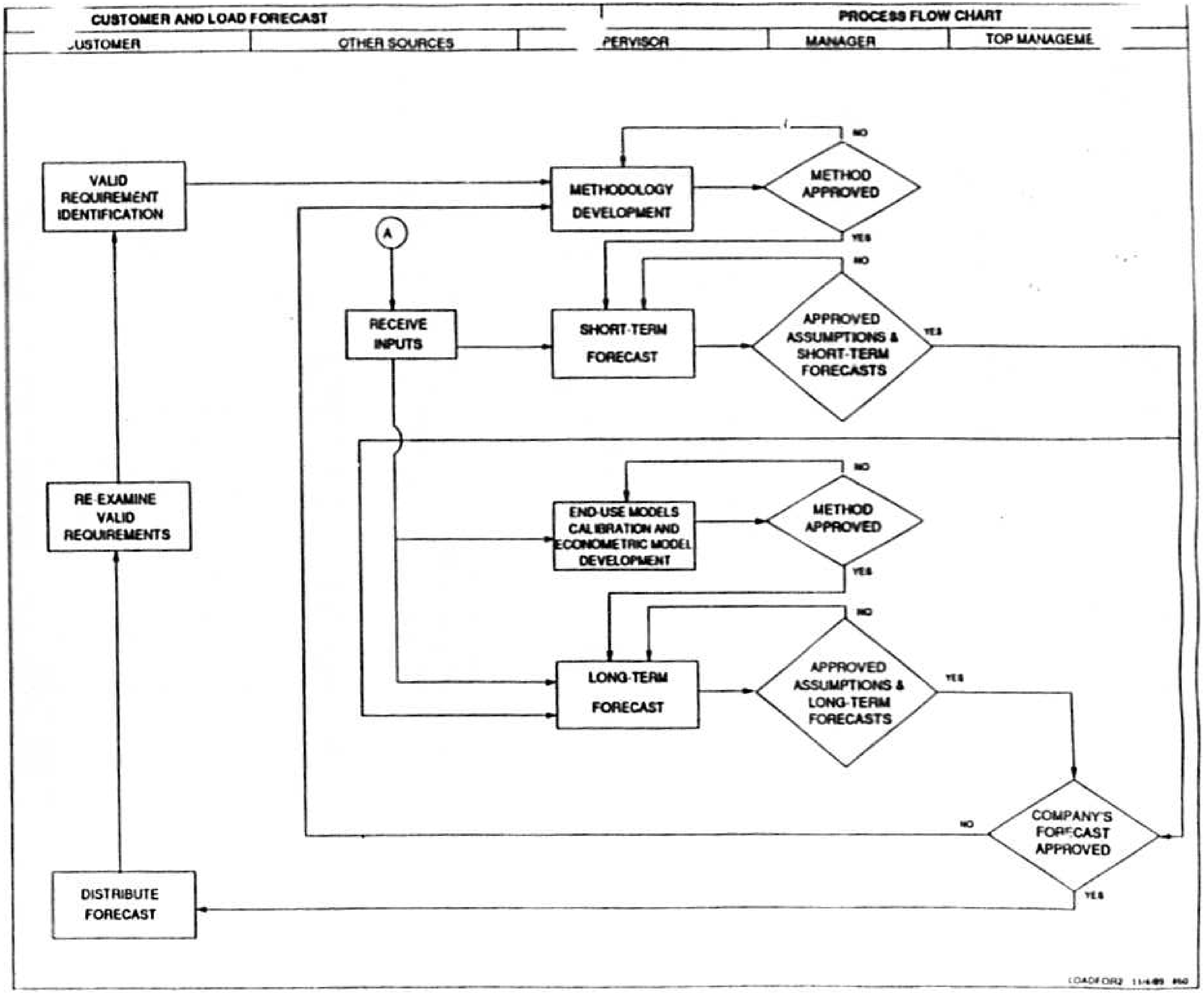
Strategic Marketing Sales Programs

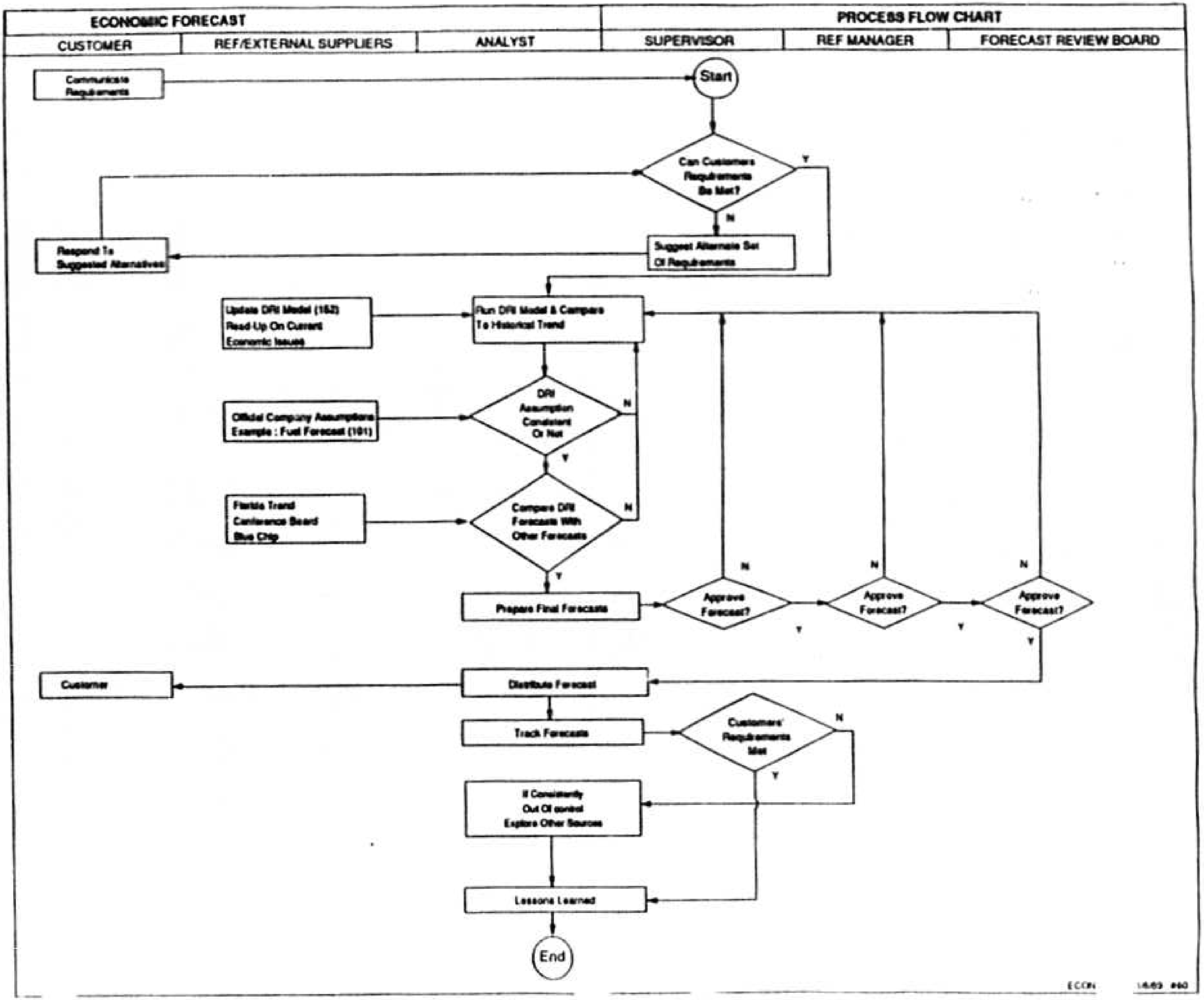
The Base forecast is also adjusted for marketing sales programs that are promoted to increase off-peak sales. The impact of these marketing programs is added to the Base Forecast.

Cogeneration

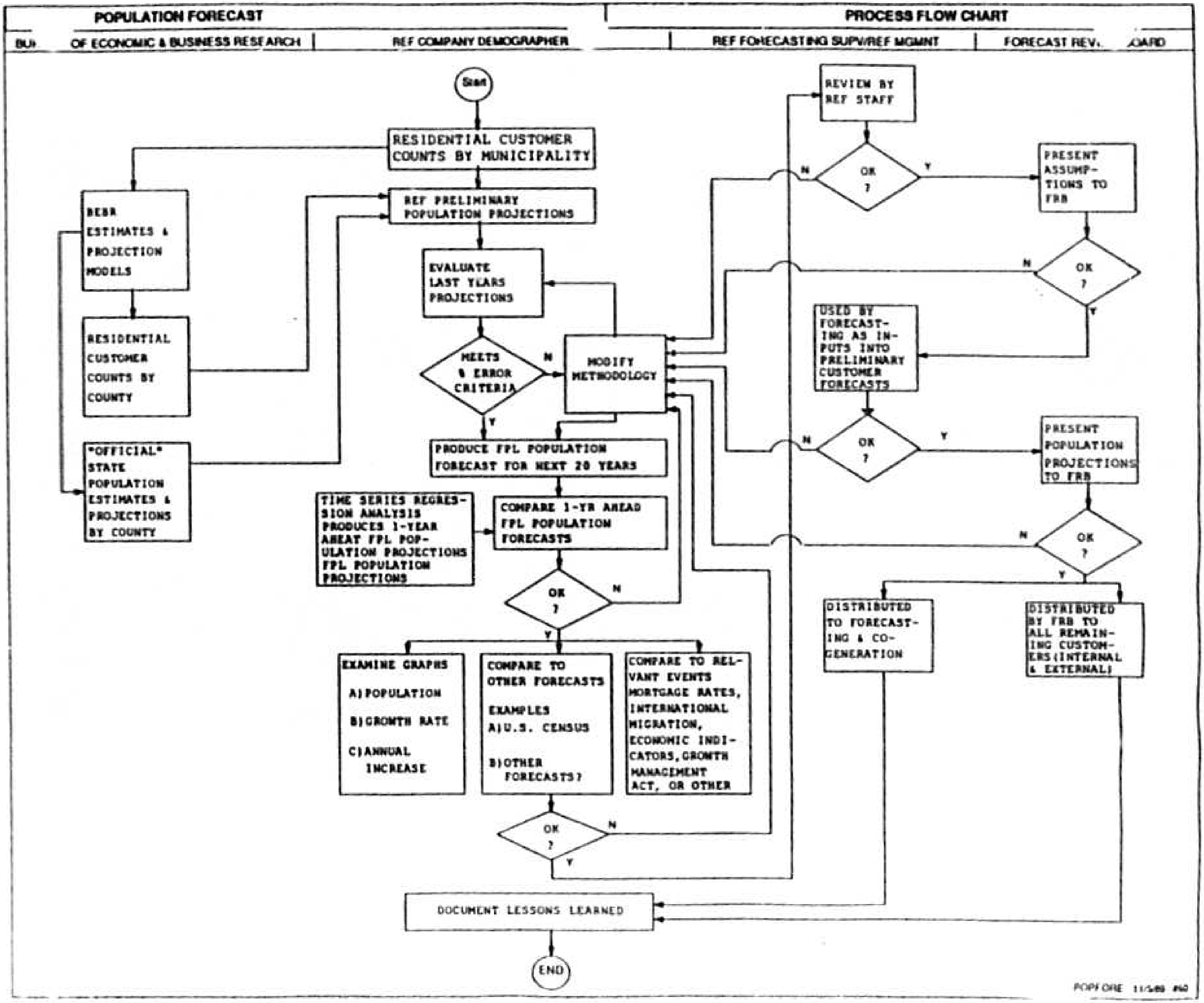
The impact of Cogeneration is subtracted from the Base Forecast. The impact of cogeneration is subtracted because it is load that FPL used to serve and will not serve any longer, once the customer becomes a cogenerator.

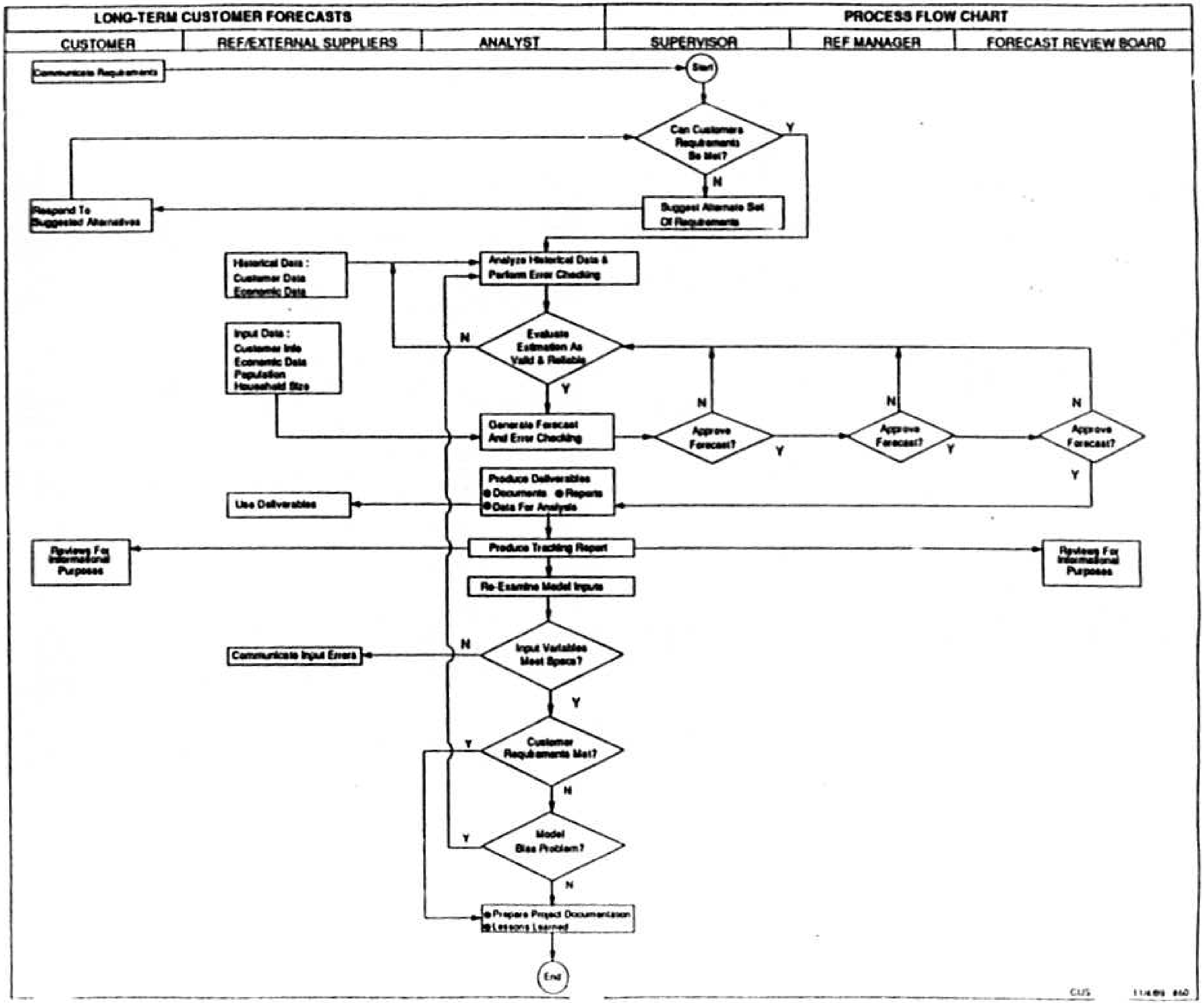
APPENDIX

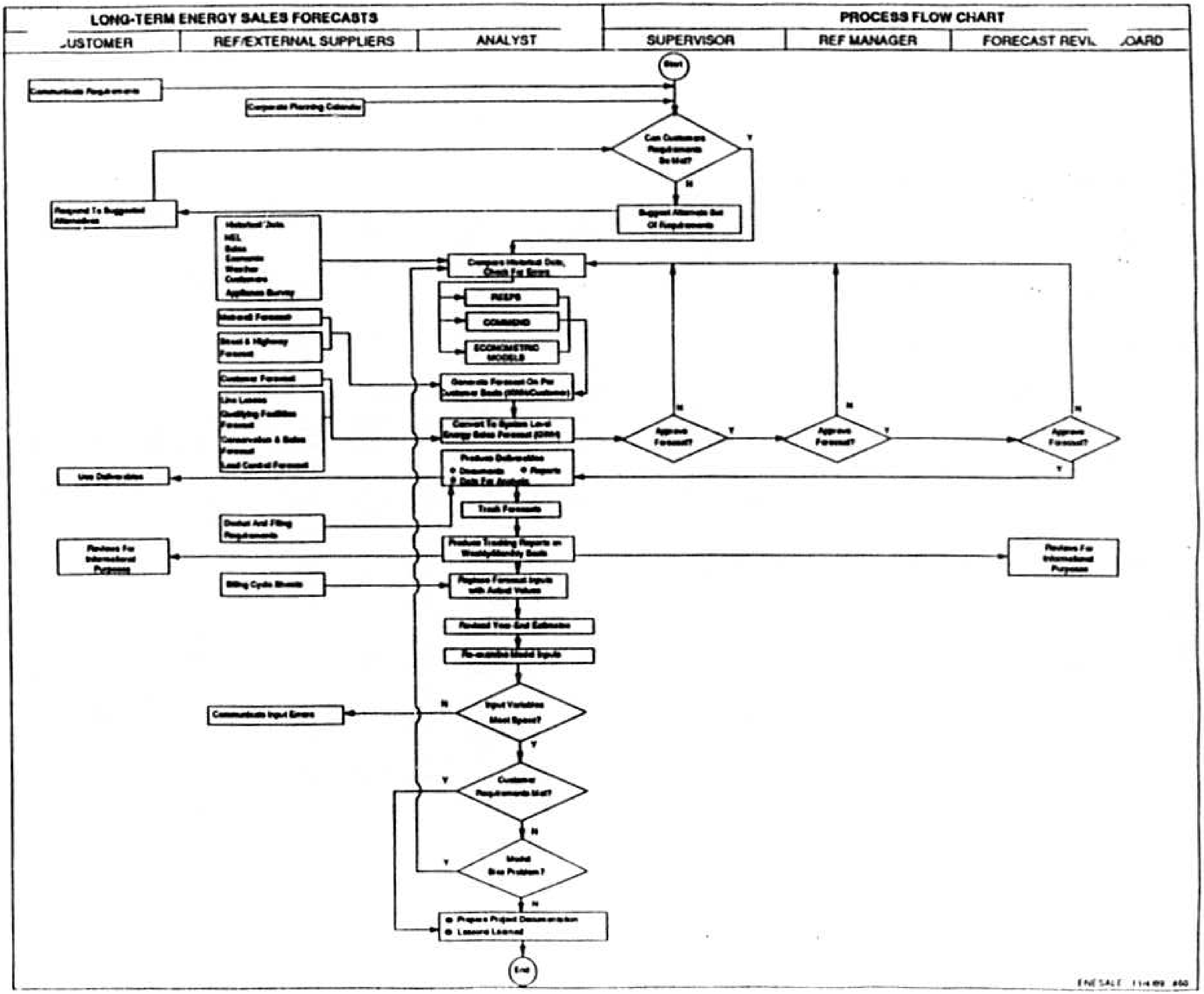

CUSTOMER AND LOAD FORECAST
PROCESS FLOW CHART
CUSTOMER
OTHER SOURCES
PERVISOR
MANAGER
TOP MANAGEME
VALID REQUIREMENT IDENTIFICATION
METHODOLOGY DEVELOPMENT
METHOD APPROVED
NO
YES
A
RECEIVE INPUTS
SHORT-TERM FORECAST
APPROVED ASSUMPTIONS & SHORT-TERM FORECASTS
NO
YES
RE-EXAMINE VALID REQUIREMENTS
END-USE MODELS CALIBRATION AND ECONOMETRIC MODEL DEVELOPMENT
METHOD APPROVED
NO
YES
LONG-TERM FORECAST
APPROVED ASSUMPTIONS & LONG-TERM FORECASTS
NO
YES
COMPANY'S FORECAST APPROVED
NO
YES
DISTRIBUTE FORECAST

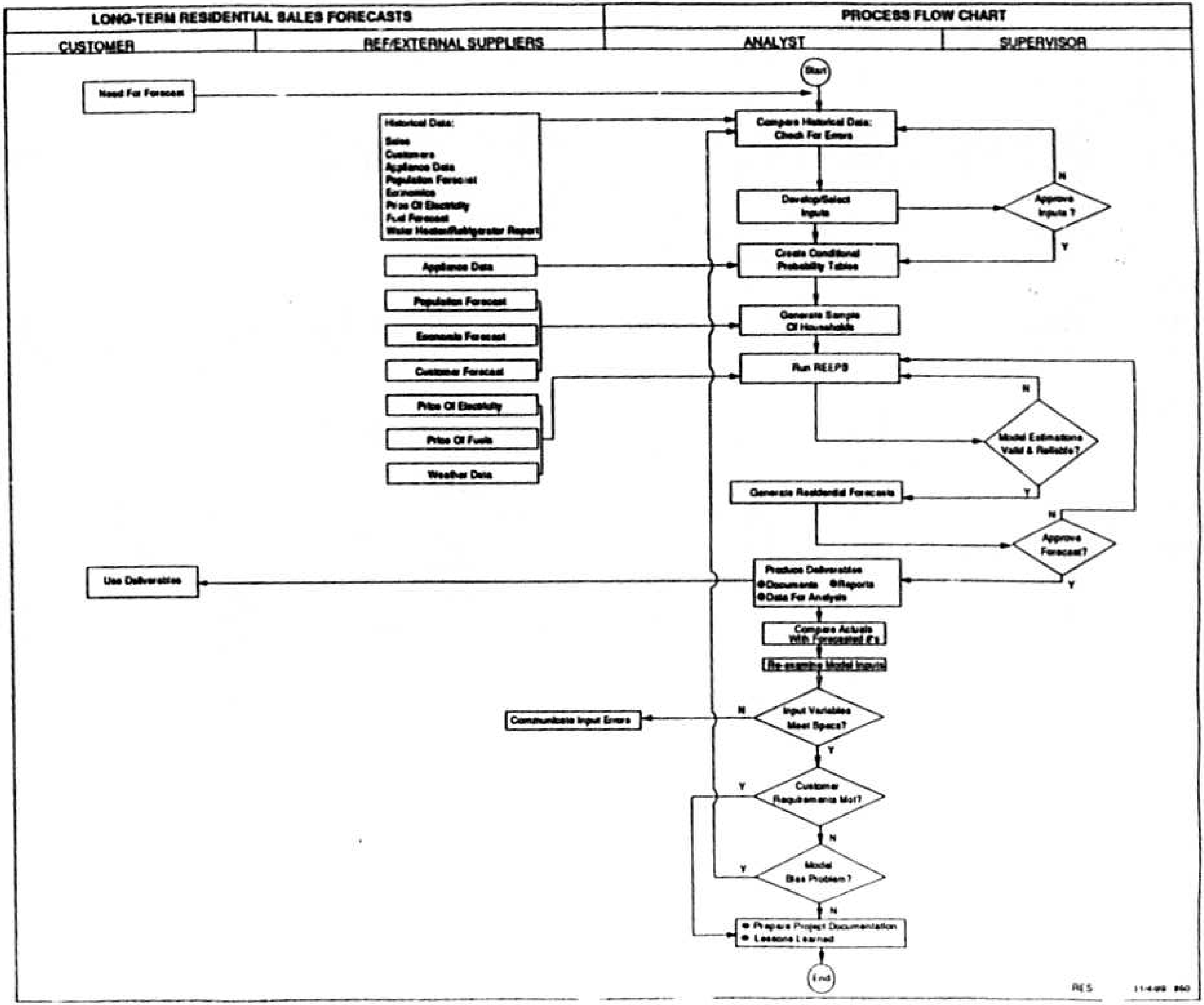


ECONOMIC FORECAST
PROCESS FLOW CHART
CUSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
REF MANAGER
FORECAST REVIEW BOARD
Communicate Requirements
Start
Can Customers Requirements Be Met?
Y
N
Respond To Suggested Alternatives
Suggest Alternate Set Of Requirements
Update DRI Model (152) Read Up On Current Economic Issues
Run DRI Model & Compare To Historical Trend
DRI Assumption Consistent Or Not
Official Company Assumptions Example : Fuel Forecast (101)
Florida Trend Conference Board Blue Chip
Compare DRI Forecasts With Other Forecasts
Prepare Final Forecasts
Approve Forecast?
Approve Forecast?
Approve Forecast?
Customer
Distribute Forecast
Track Forecasts
Customers' Requirements Met
If Consistently Out Of control Explore Other Sources
Lessons Learned
End


POPULATION FORECAST
PROCESS FLOW CHART
BU OF ECONOMIC & BUSINESS RESEARCH
REF COMPANY DEMOGRAPHER
REF FORECASTING SUPV/REF MGMNT
FORECAST REV. OARD
Start
RESIDENTIAL CUSTOMER COUNTS BY MUNICIPALITY
BEBR ESTIMATES & PROJECTION MODELS
RESIDENTIAL CUSTOMER COUNTS BY COUNTY
"OFFICIAL" STATE POPULATION ESTIMATES & PROJECTIONS BY COUNTY
REF PRELIMINARY POPULATION PROJECTIONS
EVALUATE LAST YEARS PROJECTIONS
MEETS & ERROR CRITERIA
N
MODIFY METHODOLOGY
Y
PRODUCE FPL POPULATION FORECAST FOR NEXT 20 YEARS
TIME SERIES REGRESSION ANALYSIS PRODUCES 1-YEAR AHEAT FPL POPULATION PROJECTIONS FPL POPULATION PROJECTIONS
COMPARE 1-YR AHEAD FPL POPULATION FORECASTS
OK ?
N
Y
EXAMINE GRAPHS
A) POPULATION
B) GROWTH RATE
C) ANNUAL INCREASE
COMPARE TO OTHER FORECASTS
EXAMPLES
A) U.S. CENSUS
B) OTHER FORECASTS?
COMPARE TO RELVANT EVENTS MORTGAGE RATES, INTERNATIONAL MIGRATION, ECONOMIC INDICATORS, GROWTH MANAGEMENT ACT, OR OTHER
OK ?
N
Y
REVIEW BY REF STAFF
OK ?
N
Y
PRESENT ASSUMPTIONS TO FRB
OK ?
N
Y
USED BY FORECASTING AS INPUTS INTO PRELIMINARY CUSTOMER FORECASTS
OK ?
N
Y
PRESENT POPULATION PROJECTIONS TO FRB
OK ?
N
Y
DISTRIBUTED TO FORECASTING & CO-GENERATION
DISTRIBUTED BY FRB TO ALL REMAINING CUSTOMERS (INTERNAL & EXTERNAL)
DOCUMENT LESSONS LEARNED
END
POPFORE 11/5/89 #60


LONG-TERM CUSTOMER FORECASTS
PROCESS FLOW CHART
CUSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
REF MANAGER
FORECAST REVIEW BOARD
Communicate Requirements
Start
Can Customers Requirements Be Met?
Y
N
Suggest Alternate Set Of Requirements
Respond To Suggested Alternatives
Historical Data : Customer Data Economic Data
Analyze Historical Data & Perform Error Checking
Input Data : Customer Info Economic Data Population Household Size
Evaluate Estimation As Valid & Reliable
Generate Forecast And Error Checking
Approve Forecast?
Approve Forecast?
Approve Forecast?
Produce Deliverables
Documents
Reports
Data For Analysis
Use Deliverables
Produce Tracking Report
Reviews For Informational Purposes
Reviews For Informational Purposes
Re-Examine Model Inputs
Input Variables Meet Specs?
Communicate Input Errors
Customer Requirements Met?
Model Bias Problem?
Prepare Project Documentation
Lessons Learned
End
CUS


LONG-TERM ENERGY SALES FORECASTS
PROCESS FLOW CHART
USTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
REF MANAGER
FORECAST REVI
OARD
ECONOMETRIC MODELS
Track Forecasts
Input Variables Meet Specs?
Customer Requirements Met?
Prepare Project Documentation
Lessons Learned


LONG-TERM RESIDENTIAL SALES FORECASTS
PROCESS FLOW CHART
CUSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
Start
Need For Forecast
Historical Data:
Sales
Customers
Appliance Data
Population Forecast
Economics
Price Of Electricity
Fuel Forecast
Water Heater/Refrigerator Report
Compare Historical Data; Check For Errors
Develop/Select Inputs
Approve Inputs ?
N
Y
Appliance Data
Create Conditional Probability Tables
Population Forecast
Economic Forecast
Customer Forecast
Generate Sample Of Households
Run REEPS
Price Of Electricity
Price Of Fuels
Weather Data
Model Estimations Valid & Reliable?
Generate Residential Forecasts
Approve Forecast?
Use Deliverables
Produce Deliverables
Documents
Reports
Data For Analysis
Compare Actuals With Forecasted #'s
Re-examine Model Inputs
Communicate Input Errors
Input Variables Meet Specs?
Customer Requirements Met?
Model Bias Problem ?
Prepare Project Documentation
Lessons Learned
End
RES
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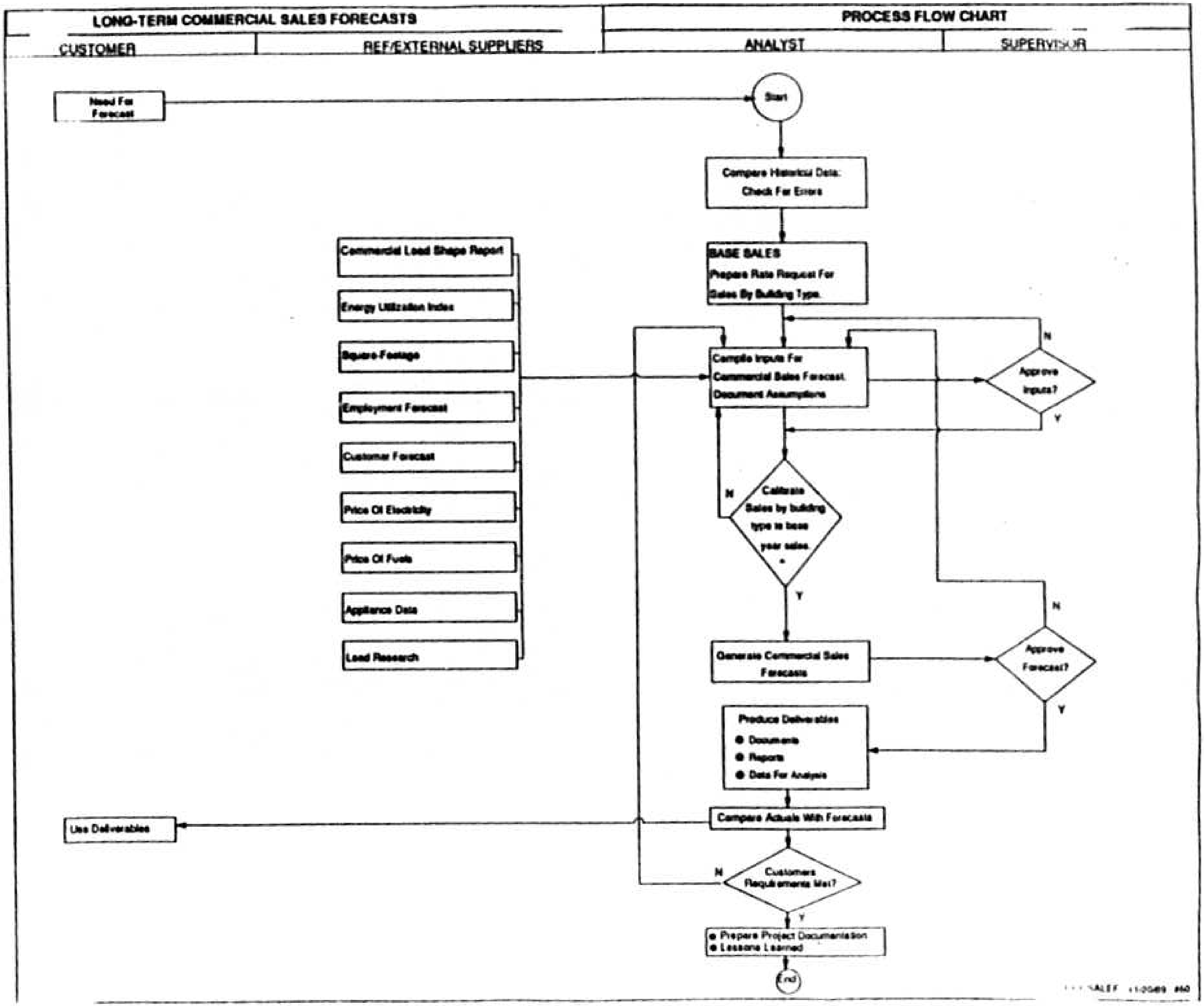
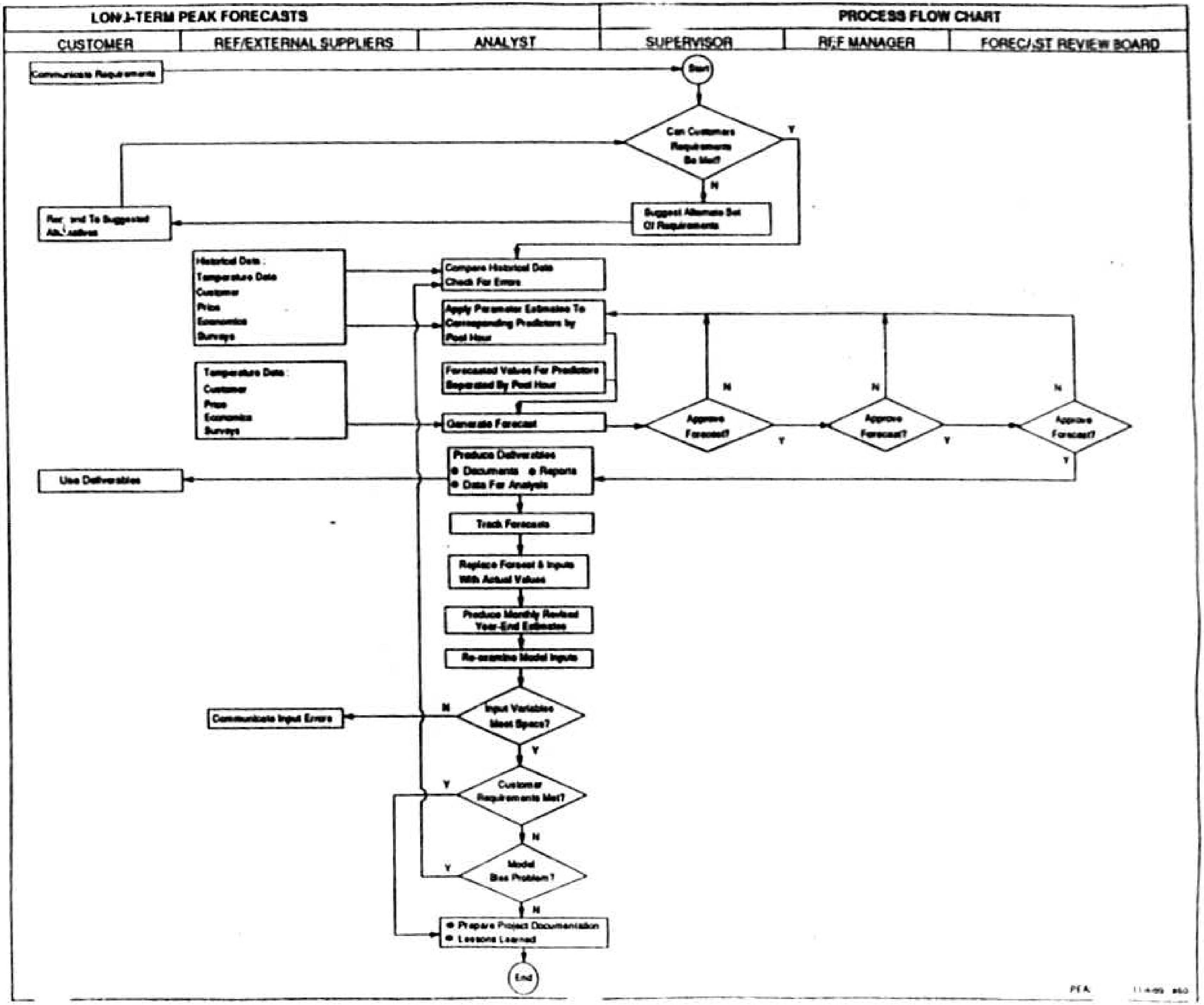

LONG-TERM COMMERCIAL SALES FORECASTS
PROCESS FLOW CHART
CUSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
Need For Forecast
Start
Compare Historical Data; Check For Errors
BASE SALES
Prepare Rate Request For Sales By Building Type.
Commercial Load Shape Report
Energy Utilization Index
Square Footage
Employment Forecast
Customer Forecast
Price Of Electricity
Price Of Fuels
Appliance Data
Load Research
Compile Inputs For Commercial Sales Forecast. Document Assumptions
Approve Inputs?
N
Y
Calibrate Sales by building type to base year sales.
N
Y
Generate Commercial Sales Forecasts
Approve Forecast?
N
Y
Produce Deliverables
Documents
Reports
Data For Analysis
Compare Actuals With Forecasts
Use Deliverables
Customers Requirements Met?
N
Y
Prepare Project Documentation
Lessons Learned
End


LONG-TERM PEAK FORECASTS
PROCESS FLOW CHART
CUSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
REF MANAGER
FORECAST REVIEW BOARD
Communicate Requirements
Start
Can Customers Requirements Be Met?
Y
N
Suggest Alternate Set Of Requirements
Respond To Suggested Alternatives
Historical Data: Temperature Data Customer Price Economics Surveys
Compare Historical Data Check For Errors
Apply Parameter Estimates To Corresponding Predictors by Peak Hour
Temperature Data: Customer Price Economics Surveys
Forecasted Values For Predictors Separated By Peak Hour
Generate Forecast
Approve Forecast?
Approve Forecast?
Approve Forecast?
Produce Deliverables
Documents
Reports
Data For Analysis
Use Deliverables
Track Forecasts
Replace Forecast & Inputs With Actual Values
Produce Monthly Revised Year-End Estimates
Re-examine Model Inputs
Input Variables Meet Specs?
Communicate Input Errors
Customer Requirements Met?
Model Bias Problem?
Prepare Project Documentation
Lessons Learned
End
PEA
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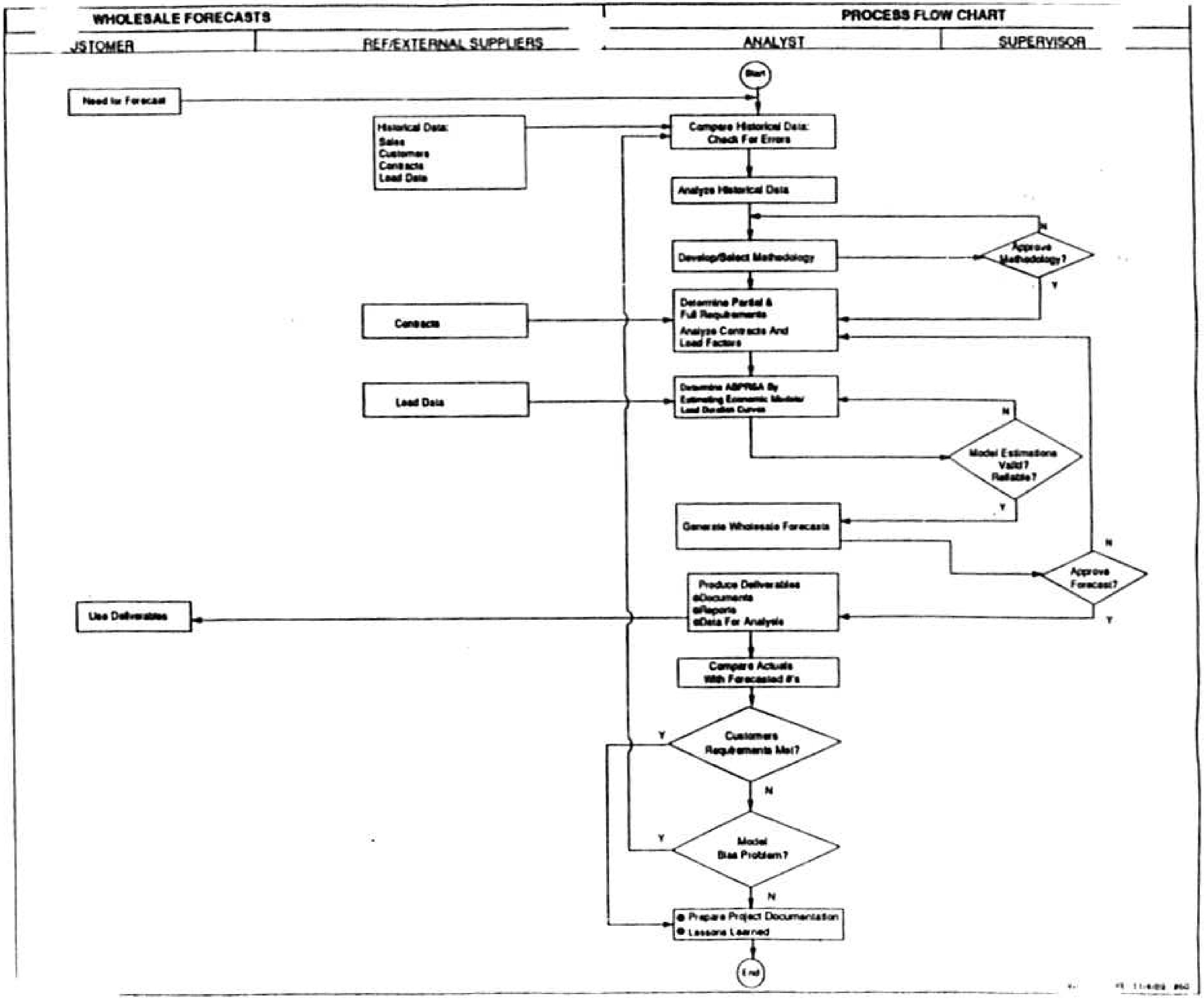

WHOLESALE FORECASTS
PROCESS FLOW CHART
JSTOMER
REF/EXTERNAL SUPPLIERS
ANALYST
SUPERVISOR
Start
Need for Forecast
Historical Data:
Sales
Customers
Contracts
Load Data
Compare Historical Data:
Check For Errors
Analyze Historical Data
Develop/Select Methodology
Approve
Methodology?
N
Y
Contracts
Determine Partial &
Full Requirements
Analyze Contracts And
Load Factors
Load Data
Model Estimations
Valid?
Reliable?
N
Y
Generate Wholesale Forecasts
Approve
Forecast?
N
Y
Produce Deliverables
Documents
Reports
Data For Analysis
Use Deliverables
Compare Actuals
With Forecasted #'s
Customers
Requirements Met?
Y
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INTRODUCTION

The Economics and Forecasting Section of the Research, Economics and Forecasting Department (REF) annually develops short and long-term projections of Company sales, customers, peak loads and NEL (net energy for load) to ensure that operational planning at FPL can be performed with appropriate information. Monthly forecasts for the 1989 - 1992 time period have been developed to support short-term planning efforts. For long-term forecasting and planning purposes, annual projections have been developed for the twenty year horizon from 1989 through 2008.

In order to ensure the integrity and validity of the forecast, a variety of traditional and innovative methodologies have been utilized. Some of these techniques include: multiple regression analysis, time-series analysis, end-use modelling and load duration curve analysis. For a detailed description of the forecasting process, please refer to the Load Forecasting Methodology manual.

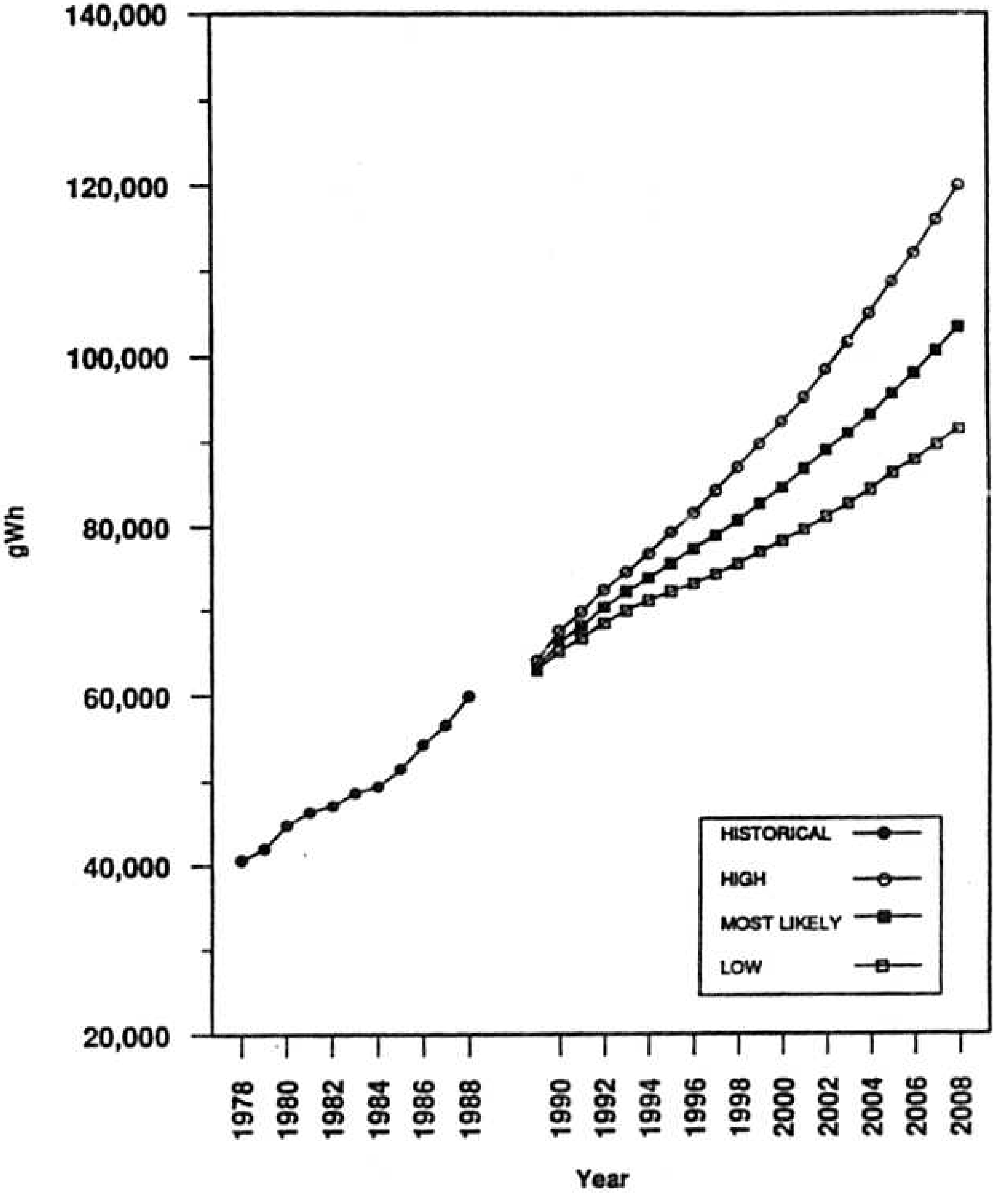
A most likely scenario and two alternative high and low scenarios have been developed to provide flexibility in planning. These alternative scenarios take into account forecasts of high and low economic activity, customer growth and nontypical (extreme, mild) weather assumptions.

This publication presents the most likely, low and high scenarios for energy sales, customers, NEL, peak load and forecast assumptions. Ten years of historical data have also been included for most data series. For your convenience, the information in this book is also available on disk. If you would like a diskette or have any questions, please call the Economics and Forecasting Section at (305) 552-3843.

SALES FORECASTS

- 1978-1988 Historical Sales By Revenue Class
- 1989-2008 Sales Forecast By Revenue Class
- Energy Sales Per Customer By Revenue Class
- Forecast Of Program Impacts On Revenue Classes
- Forecast Of Sales And Customers By Division

TOTAL ENERGY SALES



TOTAL ENERGY SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE
1978	40,602	8.2%
1979	41,965	3.4%
1980	44,707	6.5%
1981	46,262	3.5%
1982	47,072	1.8%
1983	48,589	3.2%
1984	49,351	1.6%
1985	51,434	4.2%
1986	54,276	5.5%
1987	56,592	4.3%
1988	59,892	5.8%

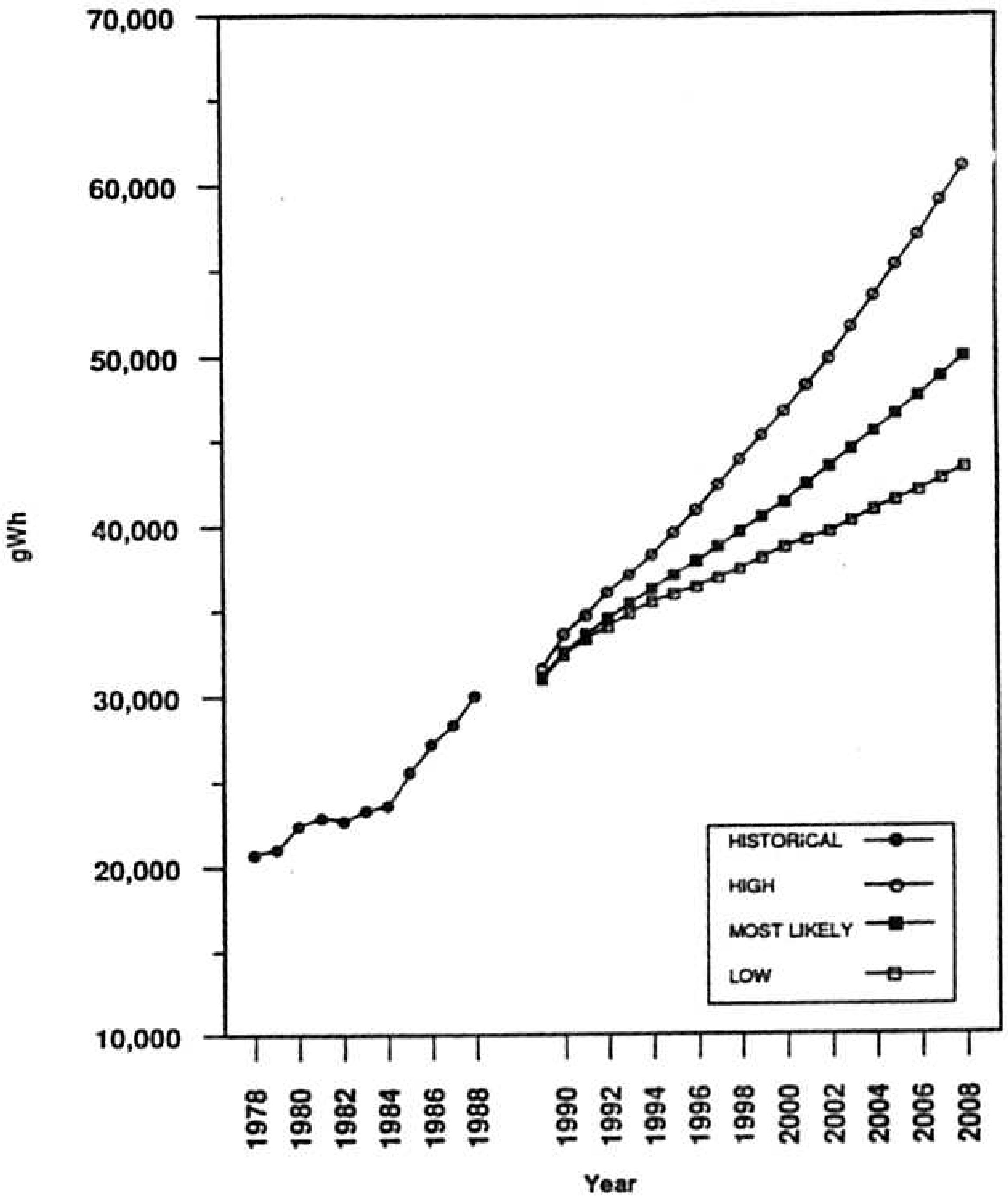
Compound Average Annual Growth Rate
1978 through 1988 4.0%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	62,906	5.0	63,191	5.5	63,986	6.8
1990	65,070	3.4	66,142	4.7	67,443	5.4
1991	66,651	2.4	68,106	3.0	69,789	3.5
1992	68,408	2.6	70,307	3.2	72,416	3.8
1993	69,917	2.2	72,192	2.7	74,512	2.9
1994	71,132	1.7	73,829	2.3	76,763	3.0
1995	72,188	1.5	75,576	2.4	79,284	3.3
1996	73,101	1.3	77,273	2.2	81,585	2.9
1997	74,263	1.6	78,896	2.1	84,161	3.2
1998	75,479	1.6	80,684	2.3	86,858	3.2
1999	76,907	1.9	82,628	2.4	89,715	3.3
2000	78,221	1.7	84,473	2.2	92,436	3.0
2001	79,592	1.8	86,665	2.6	95,359	3.2
2002	81,075	1.9	88,901	2.6	98,598	3.4
2003	82,575	1.9	90,953	2.3	101,753	3.2
2004	84,214	2.0	93,218	2.5	105,045	3.2
2005	86,130	2.3	95,737	2.7	108,708	3.5
2006	87,642	1.8	98,082	2.4	112,088	3.1
2007	89,461	2.1	100,685	2.7	116,021	3.5
2008	91,313	2.1	103,340	2.6	120,026	3.5

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.3%	3.0%	3.8%
1988-2008	2.1%	2.8%	3.5%

RESIDENTIAL SALES



RESIDENTIAL SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	20,736	8.7	51.1
1979	21,060	1.6	50.2
1980	22,432	6.5	50.2
1981	22,932	2.2	49.6
1982	22,702	-1.0	48.2
1983	23,324	2.7	48.0
1984	23,636	1.3	47.9
1985	25,573	8.2	49.7
1986	27,188	6.3	50.1
1987	28,330	4.2	50.1
1988	30,083	6.2	50.2

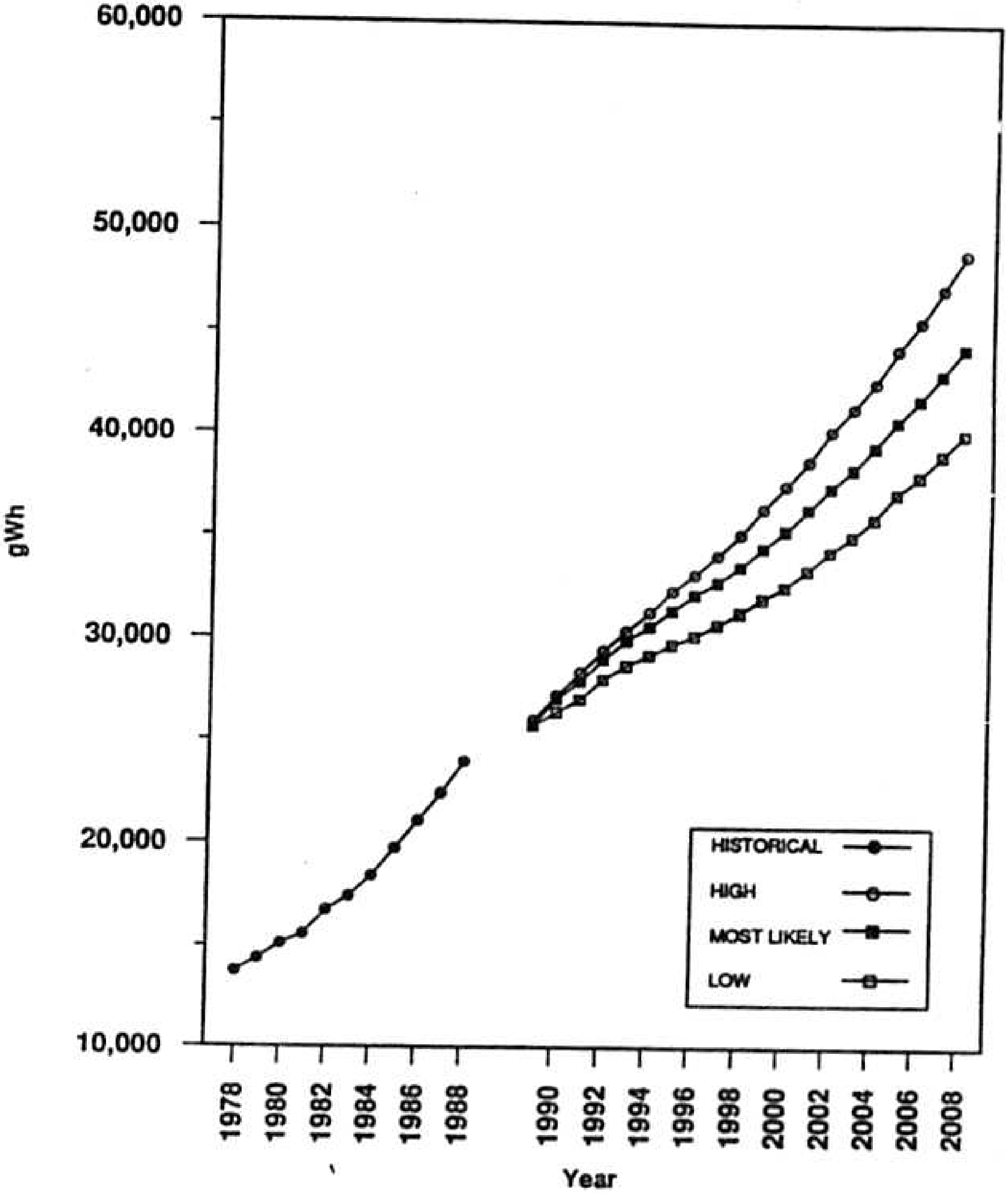
Compound Average Annual Growth Rate
1978 through 1988 3.8%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	31,070	3.3	31,236	3.8	31,700	5.4
1990	32,494	4.6	32,698	4.7	33,686	6.3
1991	33,425	2.9	33,636	2.9	34,766	3.2
1992	34,095	2.0	34,586	2.8	36,119	3.9
1993	34,888	2.3	35,443	2.5	37,158	2.9
1994	35,507	1.8	36,299	2.4	38,363	3.2
1995	35,965	1.3	37,141	2.3	39,693	3.5
1996	36,423	1.3	37,982	2.3	41,025	3.4
1997	36,971	1.5	38,864	2.3	42,497	3.6
1998	37,520	1.5	39,745	2.3	43,968	3.5
1999	38,169	1.7	40,618	2.2	45,406	3.3
2000	38,818	1.7	41,490	2.1	46,846	3.2
2001	39,273	1.2	42,541	2.5	48,412	3.3
2002	39,728	1.2	43,592	2.5	49,975	3.2
2003	40,375	1.6	44,613	2.3	51,786	3.6
2004	41,023	1.6	45,634	2.3	53,596	3.5
2005	41,586	1.4	46,702	2.3	55,381	3.3
2006	42,151	1.4	47,770	2.3	57,168	3.2
2007	42,827	1.6	48,911	2.4	59,204	3.6
2008	43,503	1.6	50,052	2.3	61,239	3.4

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.2%	2.8%	3.9%
1988-2008	1.9%	2.6%	3.6%

COMMERCIAL SALES



COMMERCIAL SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	13,748	6.7	33.9
1979	14,374	4.6	34.3
1980	15,089	5.0	33.8
1981	15,578	3.2	33.7
1982	16,745	7.5	35.6
1983	17,423	4.0	35.9
1984	18,397	5.6	37.3
1985	19,734	7.3	38.4
1986	21,078	6.8	38.8
1987	22,372	6.1	39.5
1988	23,912	6.9	39.9

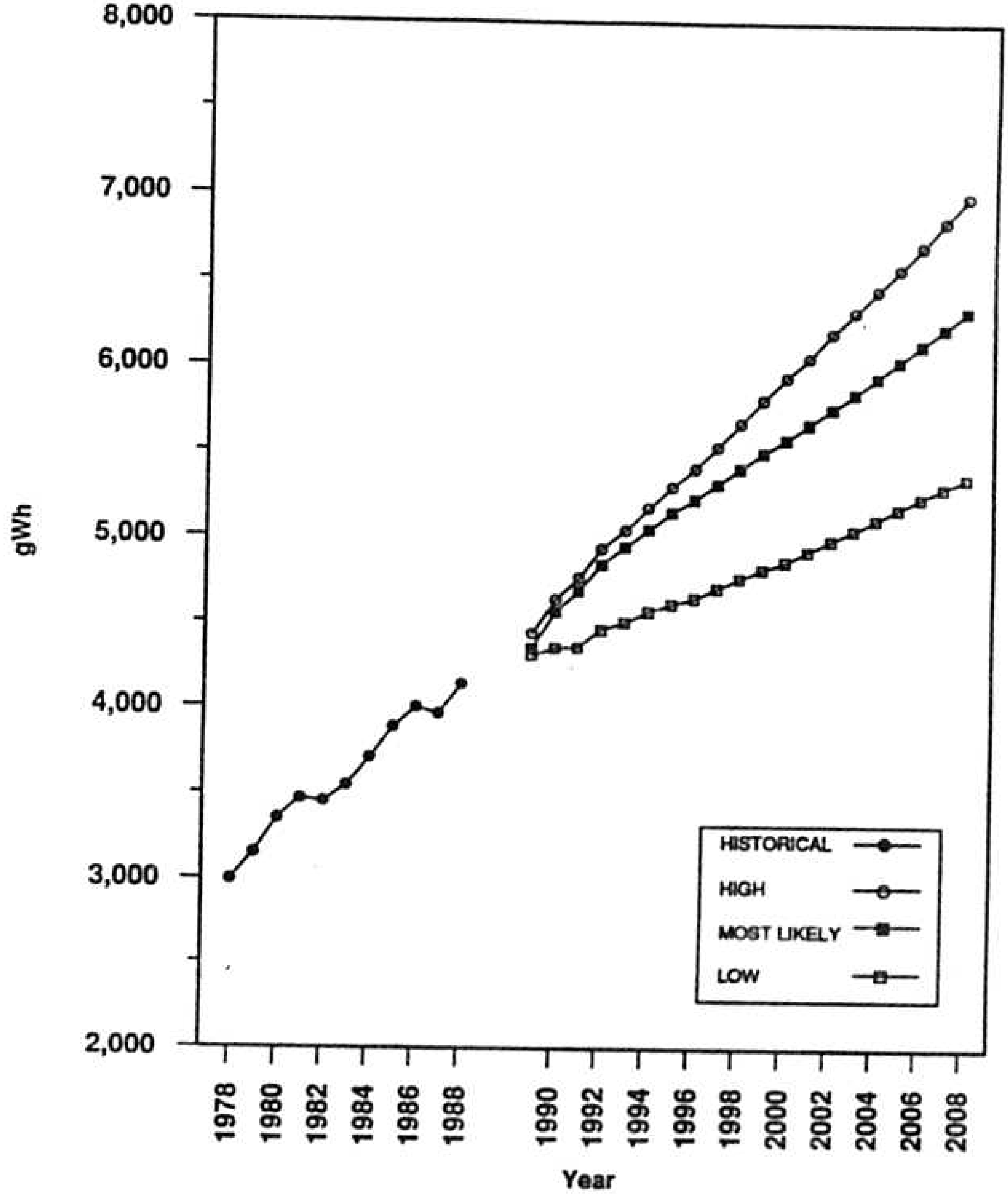
Compound Average Annual Growth Rate
1978 through 1988 5.7%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	25,708	7.5	25,768	7.8	25,997	8.7
1990	26,399	2.7	27,038	4.9	27,226	4.7
1991	27,038	2.4	27,931	3.3	28,349	4.1
1992	28,041	3.7	29,037	4.0	29,456	3.9
1993	28,711	2.4	29,940	3.1	30,382	3.1
1994	29,244	1.9	30,615	2.3	31,293	3.0
1995	29,776	1.8	31,394	2.5	32,328	3.3
1996	30,174	1.3	32,145	2.4	33,159	2.6
1997	30,717	1.8	32,779	2.0	34,115	2.9
1998	31,297	1.9	33,561	2.4	35,164	3.1
1999	31,989	2.2	34,501	2.8	36,396	3.5
2000	32,577	1.8	35,355	2.5	37,501	3.0
2001	33,397	2.5	36,366	2.9	38,689	3.2
2002	34,321	2.8	37,412	2.9	40,158	3.8
2003	35,081	2.2	38,313	2.4	41,330	2.9
2004	35,960	2.5	39,401	2.8	42,611	3.1
2005	37,175	3.4	40,667	3.2	44,251	3.8
2006	37,995	2.2	41,766	2.7	45,612	3.1
2007	38,999	2.6	43,028	3.0	47,242	3.6
2008	40,029	2.6	44,328	3.0	48,930	3.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.7%	3.4%	3.9%
1988-2008	2.6%	3.1%	3.6%

INDUSTRIAL SALES



INDUSTRIAL SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	2,993	8.6	7.4
1979	3,147	5.1	7.5
1980	3,348	6.4	7.5
1981	3,467	3.6	7.5
1982	3,449	-0.5	7.3
1983	3,544	2.8	7.3
1984	3,707	4.6	7.5
1985	3,885	4.8	7.6
1986	3,999	2.9	7.4
1987	3,962	-0.9	7.0
1988	4,132	4.3	6.9

Compound Average Annual Growth Rate
1978 through 1988 3.3%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	4,306	4.2	4,349	5.3	4,436	7.3
1990	4,353	1.1	4,566	5.0	4,636	4.5
1991	4,357	0.1	4,688	2.7	4,763	2.7
1992	4,461	2.4	4,843	3.3	4,935	3.6
1993	4,506	1.0	4,946	2.1	5,046	2.3
1994	4,569	1.4	5,049	2.1	5,176	2.6
1995	4,614	1.0	5,151	2.0	5,301	2.4
1996	4,649	0.7	5,228	1.5	5,407	2.0
1997	4,706	1.2	5,318	1.7	5,534	2.4
1998	4,766	1.3	5,409	1.7	5,671	2.5
1999	4,819	1.1	5,499	1.7	5,807	2.4
2000	4,864	0.9	5,578	1.4	5,937	2.2
2001	4,925	1.3	5,667	1.6	6,055	2.0
2002	4,990	1.3	5,757	1.6	6,202	2.4
2003	5,049	1.2	5,845	1.5	6,324	2.0
2004	5,114	1.3	5,940	1.6	6,451	2.0
2005	5,178	1.3	6,036	1.6	6,578	2.0
2006	5,241	1.2	6,133	1.6	6,711	2.0
2007	5,300	1.1	6,231	1.6	6,852	2.1
2008	5,356	1.1	6,330	1.6	6,991	2.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.4%	2.7%	3.2%
1988-2008	1.3%	2.2%	2.7%

STREET AND HIGHWAY SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	343	4.3	0.8
1979	358	4.4	0.9
1980	372	3.9	0.8
1981	382	2.7	0.8
1982	379	-0.8	0.8
1983	335	-11.6	0.7
1984	321	-4.2	0.7
1985	308	-3.9	0.6
1986	303	-1.8	0.6
1987	303	0.0	0.5
1988	310	2.3	0.5

Compound Average Annual Growth Rate
1978 through 1988 -1.0%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	318	2.7	321	3.5	325	5.0
1990	327	2.8	329	2.6	336	3.4
1991	334	2.1	338	2.8	345	2.4
1992	342	2.3	347	2.7	356	3.2
1993	347	1.4	357	2.7	365	2.6
1994	355	2.2	366	2.6	376	3.0
1995	362	2.2	376	2.6	387	3.0
1996	370	2.1	385	2.5	398	2.9
1997	378	2.1	394	2.4	409	2.8
1998	385	2.0	404	2.4	421	2.7
1999	393	2.0	413	2.3	432	2.7
2000	400	1.9	422	2.2	443	2.5
2001	408	1.8	431	2.1	454	2.5
2002	415	1.8	440	2.1	465	2.4
2003	422	1.7	450	2.1	476	2.4
2004	429	1.7	459	2.0	487	2.3
2005	436	1.7	468	2.0	498	2.3
2006	444	1.6	477	1.9	509	2.2
2007	451	1.6	486	1.9	520	2.2
2008	458	1.6	495	1.9	532	2.2

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.2%	2.7%	3.1%
1988-2008	2.0%	2.4%	2.7%

OTHER SALES TO PUBLIC AUTHORITY
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	478	0.8	1.2
1979	463	-3.1	1.1
1980	463	0.0	1.0
1981	484	4.5	1.0
1982	514	6.2	1.1
1983	518	0.8	1.1
1984	538	3.9	1.1
1985	576	7.1	1.1
1986	594	3.1	1.1
1987	602	1.3	1.1
1988	651	8.1	1.1

Compound Average Annual Growth Rate
1978 through 1988 3.1%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	680	4.5	685	5.2	692	6.3
1990	693	1.9	698	1.9	730	5.5
1991	698	0.8	703	0.7	741	1.6
1992	699	0.1	709	0.8	749	1.0
1993	707	1.1	725	2.4	765	2.2
1994	700	-1.0	719	-0.8	760	-0.7
1995	711	1.6	733	1.8	776	2.1
1996	722	1.6	746	1.9	793	2.2
1997	724	0.2	748	0.3	795	0.3
1998	736	1.7	763	2.0	813	2.3
1999	752	2.1	782	2.5	836	2.8
2000	761	1.3	794	1.5	851	1.7
2001	773	1.5	808	1.8	868	2.0
2002	786	1.8	825	2.1	889	2.4
2003	790	0.4	829	0.5	895	0.6
2004	803	1.7	846	2.0	916	2.3
2005	832	3.6	882	4.3	961	4.9
2006	848	1.8	901	2.2	985	2.5
2007	871	2.8	930	3.3	1,022	3.7
2008	894	2.7	959	3.1	1,058	3.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.2%	1.6%	2.3%
1988-2008	1.6%	2.0%	2.5%

RAILROADS & RAILWAYS ENERGY SALES
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	0	N/A	--
1979	0	N/A	--
1980	0	N/A	--
1981	0	N/A	--
1982	0	N/A	--
1983	0	N/A	--
1984	13	N/A	--
1985	53	307.7	0.1
1986	73	37.7	0.1
1987	78	6.8	0.1
1988	75	-3.8	0.1

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	79	5.7	80	7.1	83	10.3
1990	80	1.3	81	1.3	83	0.5
1991	81	0.8	82	0.4	83	0.1
1992	81	0.1	82	0.0	84	0.5
1993	80	-1.0	82	0.0	83	-0.5
1994	80	-0.0	82	0.0	83	0.0
1995	80	-0.0	82	0.0	83	0.0
1996	80	0.0	82	0.0	83	0.0
1997	80	-0.0	82	0.0	83	0.0
1998	80	-0.0	82	0.0	83	0.0
1999	81	1.4	83	1.4	84	1.4
2000	81	0.0	83	0.0	84	0.0
2001	81	0.2	83	0.2	85	0.2
2002	81	-0.0	83	0.0	85	-0.0
2003	81	-0.0	83	0.0	85	0.0
2004	81	-0.0	83	0.0	85	0.0
2005	83	2.4	85	2.4	87	2.4
2006	83	-0.0	85	0.0	87	0.0
2007	83	-0.0	85	0.0	87	0.0
2008	83	-0.0	85	0.0	87	0.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	0.7%	0.9%	1.1%
1988-2008	0.5%	0.6%	0.7%

SALES FOR RESALE
HISTORY AND FORECAST

YEAR	GWH	ANNUAL % CHANGE	% SYSTEM TOTAL SALES
1978	2304	14.5	5.7
1979	2563	11.2	6.1
1980	3003	17.2	6.7
1981	3419	13.9	7.4
1982	3283	-4.0	7.0
1983	3445	4.9	7.1
1984	2739	-20.5	5.6
1985	1304	-52.4	2.5
1986	1040	-20.2	1.9
1987	944	-9.2	1.7
1988	729	-22.8	1.2

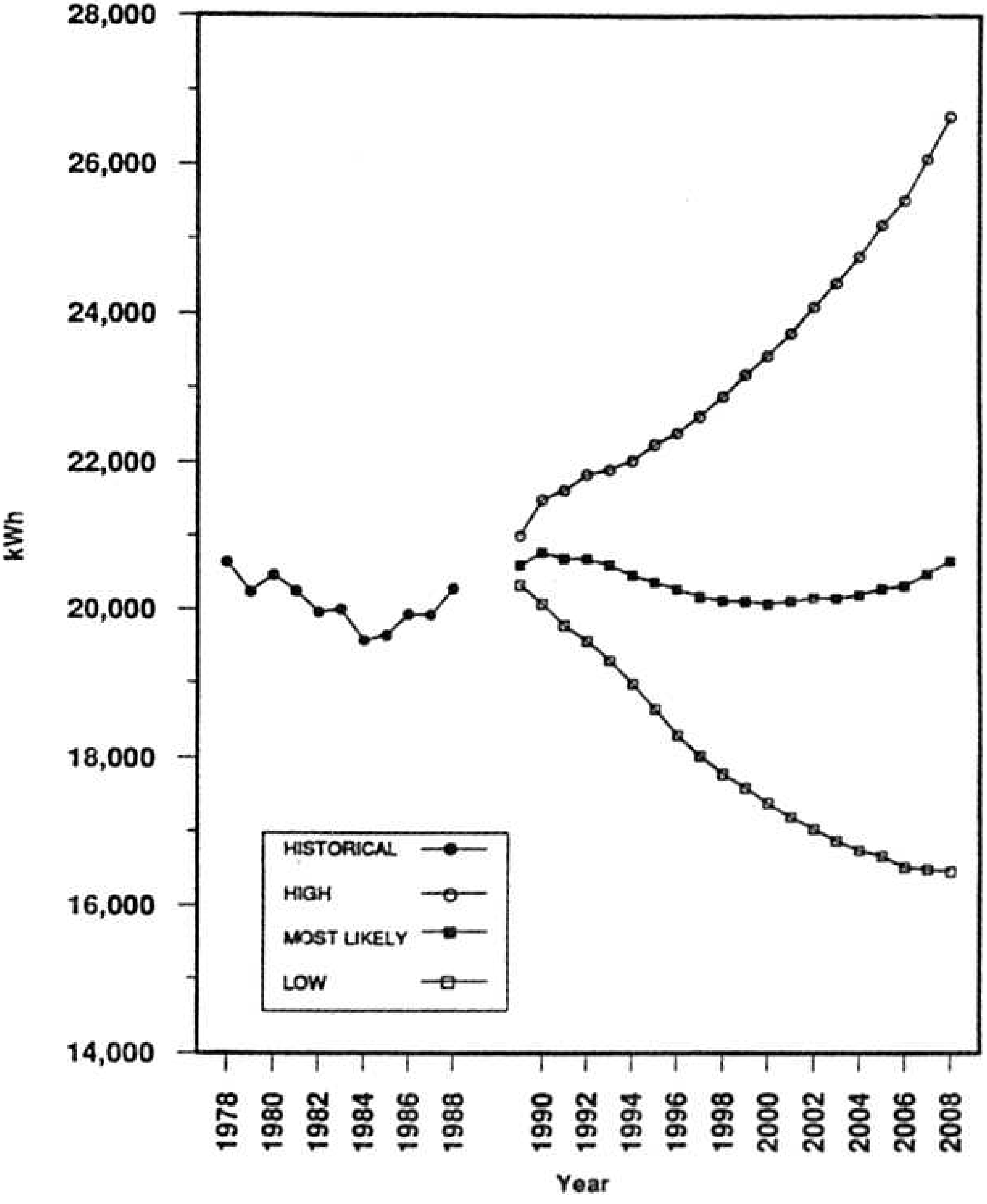
Compound Average Annual Growth Rate
1978 through 1988 -10.9%

YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	744	2.1	752	3.1	753	3.3
1990	723	-2.8	730	-2.9	746	-0.9
1991	717	-0.8	728	-0.2	742	-0.5
1992	689	-3.9	702	-3.6	719	-3.1
1993	678	-1.6	700	-0.4	714	-0.7
1994	677	-0.1	699	-0.0	713	-0.0
1995	679	0.2	701	0.2	715	0.3
1996	682	0.4	704	0.5	720	0.6
1997	687	0.7	711	0.9	727	1.0
1998	694	1.1	720	1.3	738	1.5
1999	705	1.5	733	1.8	753	2.1
2000	720	2.1	751	2.4	774	2.8
2001	734	2.1	769	2.4	796	2.8
2002	753	2.5	792	3.0	823	3.4
2003	776	3.1	820	3.6	858	4.2
2004	804	3.6	855	4.3	900	4.9
2005	839	4.3	898	5.0	952	5.8
2006	880	4.9	951	5.8	1,016	6.7
2007	930	5.7	1,014	6.7	1,094	7.7
2008	990	6.4	1,091	7.6	1,189	8.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-0.5%	-0.1%	0.1%
1988-2008	1.5%	2.0%	2.5%

TOTAL ENERGY SALES PER CUSTOMER



TOTAL ENERGY SALES PER CUSTOMER
HISTORY AND FORECAST

YEAR	KWH/CUSTOMER	ANNUAL % CHANGE
1978	20,638	3.2
1979	20,231	-2.0
1980	20,461	1.1
1981	20,244	-1.1
1982	19,961	-1.4
1983	19,998	0.2
1984	19,580	-2.1
1985	19,650	0.4
1986	19,928	1.4
1987	19,925	-0.0
1988	20,278	1.8

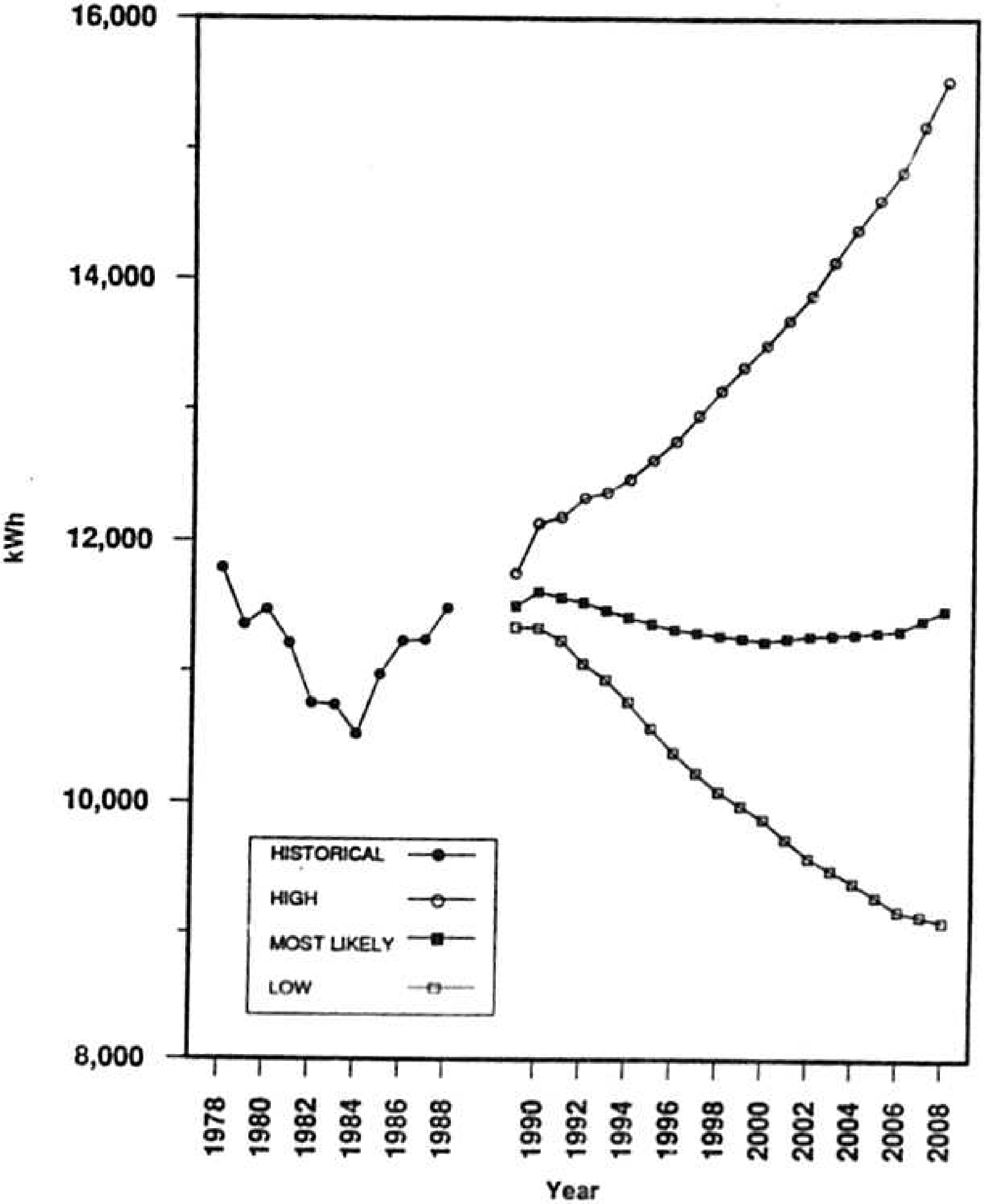
Compound Average Annual Growth Rate
1978 through 1988 -0.2%

YEAR	LOW KWH	ANNUAL % CHANGE	MOST LIKELY KWH	ANNUAL % CHANGE	HIGH KWH	ANNUAL % CHANGE
1989	20,327	0.2	20,602	1.6	21,017	3.6
1990	20,078	-1.2	20,780	0.9	21,504	2.3
1991	19,795	-1.4	20,693	-0.4	21,633	0.6
1992	19,583	-1.1	20,692	-0.0	21,847	1.0
1993	19,319	-1.3	20,607	-0.4	21,912	0.3
1994	18,994	-1.7	20,466	-0.7	22,035	0.6
1995	18,650	-1.8	20,370	-0.5	22,243	0.9
1996	18,298	-1.9	20,275	-0.5	22,395	0.7
1997	18,029	-1.5	20,174	-0.5	22,626	1.0
1998	17,786	-1.3	20,124	-0.2	22,890	1.2
1999	17,601	-1.0	20,114	-0.0	23,192	1.3
2000	17,394	-1.2	20,078	-0.2	23,450	1.1
2001	17,206	-1.1	20,119	0.2	23,744	1.3
2002	17,041	-1.0	20,162	0.2	24,103	1.5
2003	16,882	-0.9	20,158	-0.0	24,429	1.4
2004	16,753	-0.8	20,197	0.2	24,776	1.4
2005	16,677	-0.5	20,284	0.4	25,198	1.7
2006	16,525	-0.9	20,326	0.2	25,535	1.3
2007	16,495	-0.2	20,498	0.8	26,091	2.2
2008	16,467	-0.2	20,671	0.8	26,648	2.1

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-1.3%	-0.1%	1.2%
1988-2008	-1.0%	0.1%	1.4%

RESIDENTIAL ENERGY SALES PER CUSTOMER



RESIDENTIAL ENERGY SALES PER CUSTOMER
HISTORY AND FORECAST

YEAR	KWH/CUSTOMER	ANNUAL % CHANGE
1978	11,790	3.7
1979	11,354	-3.7
1980	11,473	1.0
1981	11,216	-2.2
1982	10,757	-4.1
1983	10,745	-0.1
1984	10,520	-2.1
1985	10,977	4.3
1986	11,236	2.4
1987	11,243	0.1
1988	11,491	2.2

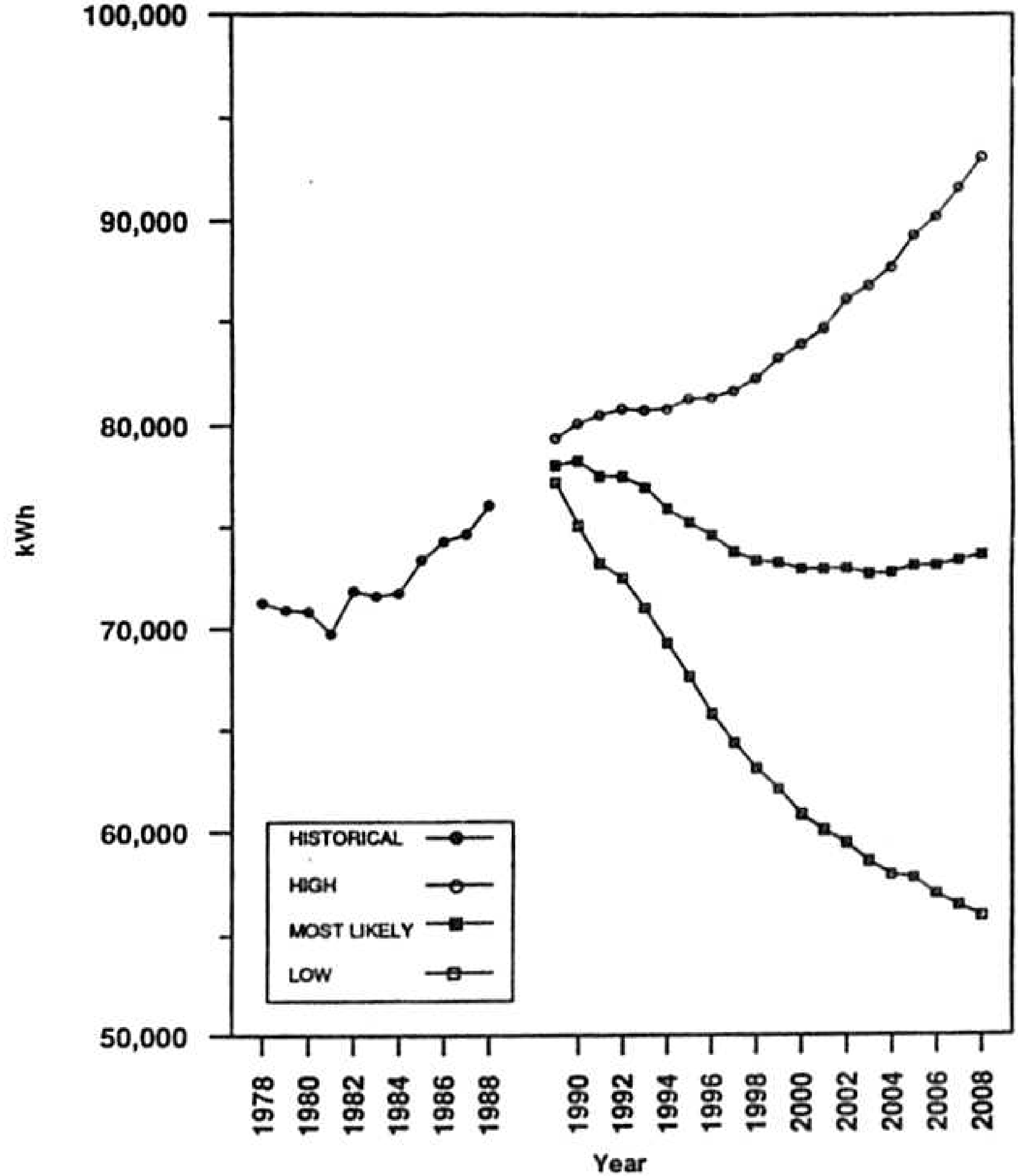
Compound Average Annual Growth Rate
1978 through 1988 -0.3%

YEAR	LOW KWH	ANNUAL % CHANGE	MOST LIKELY KWH	ANNUAL % CHANGE	HIGH KWH	ANNUAL % CHANGE
1989	11,341	-1.3	11,505	0.1	11,762	2.4
1990	11,336	-0.0	11,617	1.0	12,144	3.2
1991	11,240	-0.8	11,572	-0.4	12,195	0.4
1992	11,066	-1.5	11,537	-0.3	12,343	1.2
1993	10,942	-1.1	11,476	-0.5	12,387	0.4
1994	10,774	-1.5	11,423	-0.5	12,490	0.8
1995	10,571	-1.9	11,372	-0.4	12,636	1.2
1996	10,384	-1.8	11,328	-0.4	12,783	1.2
1997	10,234	-1.4	11,303	-0.2	12,974	1.5
1998	10,093	-1.4	11,281	-0.2	13,163	1.5
1999	9,985	-1.1	11,260	-0.2	13,339	1.3
2000	9,881	-1.0	11,238	-0.2	13,511	1.3
2001	9,730	-1.5	11,262	0.2	13,711	1.5
2002	9,583	-1.5	11,281	0.2	13,902	1.4
2003	9,486	-1.0	11,290	0.1	14,154	1.8
2004	9,390	-1.0	11,297	0.1	14,398	1.7
2005	9,277	-1.2	11,312	0.1	14,627	1.6
2006	9,170	-1.2	11,325	0.1	14,844	1.5
2007	9,130	-0.4	11,406	0.7	15,188	2.3
2008	9,089	-0.4	11,482	0.7	15,524	2.2

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-1.3%	-0.2%	1.4%
1988-2008	-1.2%	-0.0%	1.5%

COMMERCIAL ENERGY SALES PER CUSTOMER



COMMERCIAL ENERGY SALES PER CUSTOMER
HISTORY AND FORECAST

YEAR	KWH/CUSTOMER	ANNUAL % CHANGE
1978	71,289	2.2
1979	70,922	-0.5
1980	70,855	-0.1
1981	69,732	-1.6
1982	71,894	3-1
1983	71,620	-0.4
1984	71,778	0.2
1985	73,421	2.3
1986	74,337	1.2
1987	74,664	0.4
1988	76,065	1.9

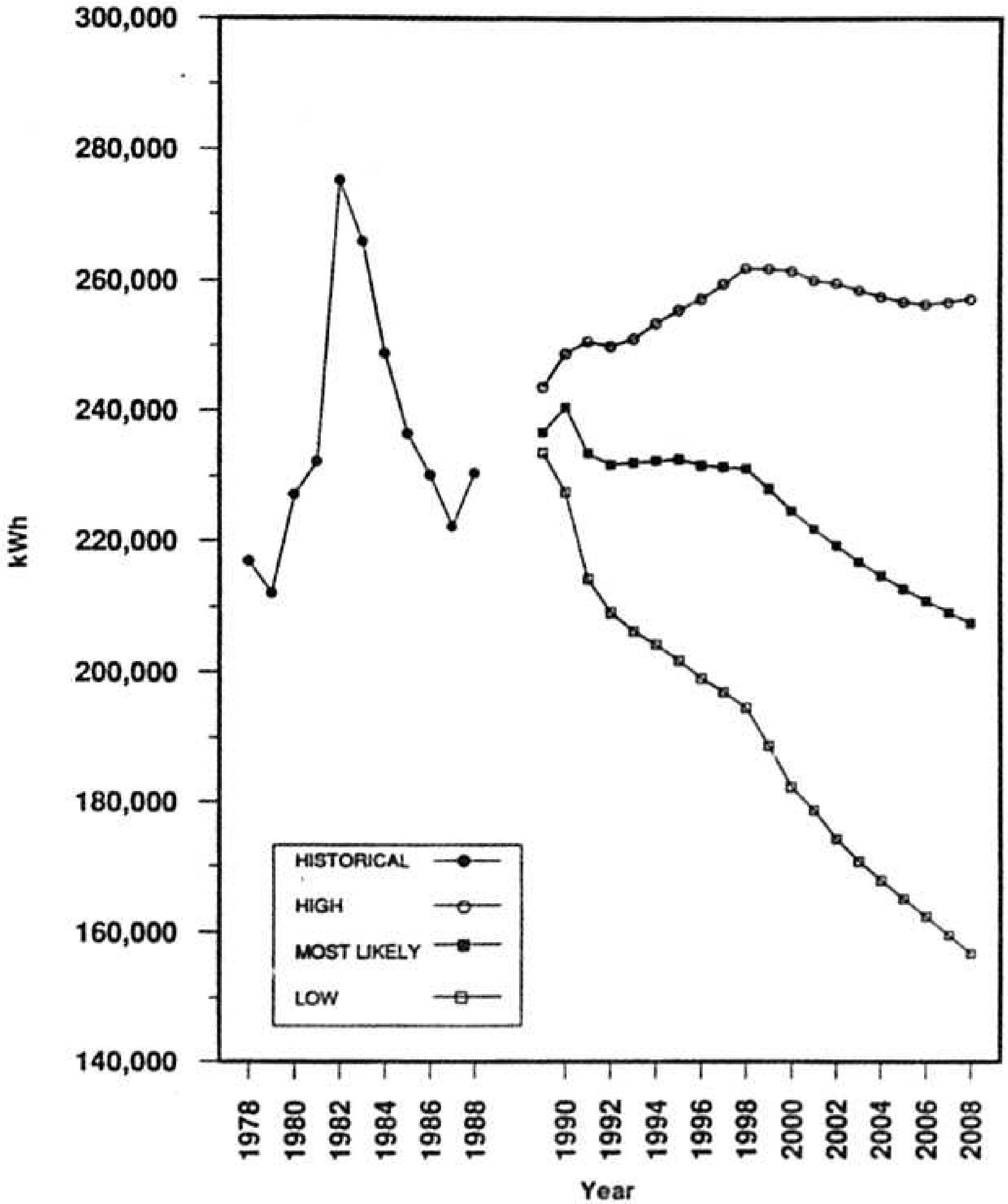
Compound Average Annual Growth Rate
1978 through 1988 0.7%

YEAR	LOW KWH	ANNUAL % CHANGE	MOST LIKELY KWH	ANNUAL % CHANGE	HIGH KWH	ANNUAL % CHANGE
1989	77,187	1.5	77,988	2.5	79,311	4.3
1990	75,092	-2.7	78,222	0.3	80,043	0.9
1991	73,242	-2.5	77,478	-1.0	80,476	0.5
1992	72,511	-1.0	77,464	-0.0	80,773	0.4
1993	70,982	-2.1	76,934	-0.7	80,706	-0.1
1994	69,225	-2.5	75,914	-1.3	80,765	0.1
1995	67,596	-2.4	75,257	-0.9	81,261	0.6
1996	65,792	-2.7	74,634	-0.8	81,306	0.1
1997	64,364	-2.2	73,786	-1.1	81,650	0.4
1998	63,089	-2.0	73,345	-0.6	82,266	0.8
1999	62,053	-1.6	73,243	-0.1	83,288	1.2
2000	60,817	-2.0	72,928	-0.4	83,968	0.8
2001	60,091	-1.2	72,921	-0.0	84,756	0.9
2002	59,480	-1.0	72,944	0.0	86,093	1.6
2003	58,615	-1.5	72,666	-0.4	86,764	0.8
2004	57,945	-1.1	72,726	0.1	87,639	1.0
2005	57,781	-0.3	73,069	0.5	89,200	1.8
2006	56,959	-1.4	73,073	0.0	90,151	1.1
2007	56,385	-1.0	73,324	0.3	91,596	1.6
2008	55,840	-1.0	73,591	0.4	93,091	1.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-1.9%	-0.4%	0.8%
1988-2008	-1.5%	-0.2%	1.0%

INDUSTRIAL ENERGY SALES PER CUSTOMER



INDUSTRIAL ENERGY SALES PER CUSTOMER
HISTORY AND FORECAST

YEAR	KWH/CUSTOMER	ANNUAL % CHANGE
1978	216,900	-7.2
1979	212,105	-2.2
1980	227,230	7.1
1981	232,326	2.2
1982	275,259	18.5
1983	265,807	-3.4
1984	248,926	-6.4
1985	236,515	-5.0
1986	230,185	-2.7
1987	222,285	-3.4
1988	230,542	3.7

Compound Average Annual Growth Rate
1978 through 1988 0.6%

YEAR	LOW KWH	ANNUAL % CHANGE	MOST LIKELY KWH	ANNUAL % CHANGE	HIGH KWH	ANNUAL % CHANGE
1989	233,606	1.3	236,689	2.7	243,613	5.7
1990	227,607	-2.6	240,519	1.6	248,915	2.2
1991	214,126	-5.9	233,540	-2.9	250,767	0.7
1992	209,027	-2.4	231,819	-0.7	250,106	-0.3
1993	206,265	-1.3	232,099	0.1	251,141	0.4
1994	204,288	-1.0	232,413	0.1	253,420	0.9
1995	201,824	-1.2	232,637	0.1	255,415	0.8
1996	199,061	-1.4	231,724	-0.4	257,082	0.7
1997	196,888	-1.1	231,431	-0.1	259,328	0.9
1998	194,512	-1.2	231,214	-0.1	261,798	1.0
1999	188,647	-3.0	228,075	-1.4	261,705	-0.0
2000	182,299	-3.4	224,721	-1.5	261,413	-0.1
2001	178,693	-2.0	221,896	-1.3	259,949	-0.6
2002	174,144	-2.5	219,317	-1.2	259,532	-0.2
2003	170,730	-2.0	216,777	-1.2	258,384	-0.4
2004	167,791	-1.7	214,613	-1.0	257,422	-0.4
2005	165,009	-1.7	212,589	-0.9	256,543	-0.3
2006	162,245	-1.7	210,701	-0.9	256,210	-0.1
2007	159,252	-1.8	208,938	-0.8	256,515	0.1
2008	156,451	-1.8	207,301	-0.8	257,011	0.2

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-1.7%	0.0%	1.3%
1988-2008	-1.9%	-0.5%	0.5%

FORECAST OF PROGRAM IMPACTS ON TOTAL ENERGY SALES

(GWH)

YEAR	BASE TOTAL SALES FORECAST	DEMAND SIDE PROGRAMS: SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL TOTAL SALES FORECAST*	SUPPLY SIDE OPTIONS: LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	TOTAL FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	63,295	29.1	(76.1)	(56.3)	63,191	(1.5)	(18.2)	63,172
1990	66,467	63.9	(152.8)	(236.0)	66,142	(3.7)	(31.8)	66,106
1991	68,692	106.6	(222.1)	(470.8)	68,106	(7.1)	(45.5)	68,053
1992	70,947	154.3	(285.5)	(509.2)	70,307	(11.1)	(60.9)	70,235
1993	72,861	202.0	(348.9)	(521.5)	72,192	(15.1)	(60.9)	72,116
1994	74,514	249.7	(412.3)	(521.5)	73,829	(19.5)	(60.9)	73,749
1995	76,288	297.4	(475.7)	(533.8)	75,576	(24.5)	(60.9)	75,491
1996	78,123	345.1	(539.1)	(656.4)	77,273	(29.6)	(60.9)	77,182
1997	79,780	392.8	(602.5)	(674.8)	78,896	(32.5)	(60.9)	78,802
1998	81,589	440.5	(665.9)	(679.9)	80,684	(32.7)	(60.9)	80,590
1999	83,568	488.2	(729.3)	(698.3)	82,628	(32.7)	(60.9)	82,535
2000	85,514	535.9	(792.7)	(784.1)	84,473	(32.7)	(60.9)	84,379
2001	87,729	583.6	(851.0)	(796.4)	86,665	(32.7)	(60.9)	86,571
2002	89,986	631.3	(919.5)	(796.4)	88,901	(32.7)	(60.9)	88,808
2003	92,071	679.0	(982.9)	(814.8)	90,953	(32.7)	(60.9)	90,859
2004	94,352	726.7	(1,046.3)	(814.8)	93,218	(32.7)	(60.9)	93,124
2005	96,900	774.4	(1,109.7)	(827.1)	95,737	(32.7)	(60.9)	95,644
2006	99,260	822.1	(1,173.1)	(827.1)	98,082	(32.7)	(60.9)	97,98[illegible]
2007	101,879	869.8	(1,236.5)	(827.1)	100,685	(32.7)	(60.9)	100,591
2008	104,550	917.5	(1,299.9)	(827.1)	103,340	(32.7)	(60.9)	103,247

* This is the official forecast approved by the Forecast Review Board

FORECAST OF PROGRAM IMPACTS ON RESIDENTIAL ENERGY SALES
(GWH)

YEAR	BASE RESIDENTIAL SALES FORECAST	DEMAND SIDE PROGRAMS: SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL RESIDENTIAL SALES FORECAST*	SUPPLY SIDE OPTIONS: LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	RESIDENTIAL FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	31,262	15.9	(41.7)	0	31,236	(1.5)	0	31,235
1990	32,747	34.9	(83.4)	0	32,698	(3.7)	0	32,695
1991	33,699	57.9	(120.6)	0	33,636	(7.1)	0	33,629
1992	34,657	83.3	(154.1)	0	34,586	(11.1)	0	34,575
1993	35,522	108.8	(187.8)	0	35,443	(15.1)	0	35,428
1994	36,386	134.6	(222.2)	0	36,299	(19.5)	0	36,279
1995	37,237	160.1	(256.1)	0	37,141	(24.5)	0	37,116
1996	38,087	185.4	(289.7)	0	37,982	(29.6)	0	37,953
1997	38,977	211.4	(324.2)	0	38,864	(32.5)	0	38,831
1998	39,866	236.9	(358.2)	0	39,745	(32.7)	0	39,712
1999	40,747	261.9	(391.2)	0	40,618	(32.7)	0	40,585
2000	41,628	286.8	(424.3)	0	41,490	(32.7)	0	41,458
2001	42,684	311.9	(454.8)	0	42,541	(32.7)	0	42,508
2002	43,746	336.9	(490.6)	0	43,592	(32.7)	0	43,559
2003	44,775	362.2	(524.3)	0	44,613	(32.7)	0	44,580
2004	45,804	386.8	(556.9)	0	45,634	(32.7)	0	45,601
2005	46,880	410.6	(588.3)	0	46,702	(32.7)	0	46,669
2006	47,956	435.1	(620.9)	0	47,770	(32.7)	0	47,737
2007	49,104	459.1	(652.7)	0	48,911	(32.7)	0	48,878
2008	50,253	482.9	(684.1)	0	50,052	(32.7)	0	50,019

* This is the official forecast approved by the Forecast Review Board

FORECAST OF PROGRAM IMPACTS ON COMMERCIAL ENERGY SALES
(GWH)

		DEMAND SIDE PROGRAMS				SUPPLY SIDE OPTIONS		
YEAR	BASE COMMERCIAL SALES FORECAST	SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL COMMERCIAL SALES FORECAST*	LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	COMMERCIAL FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	25,837	13.2	(34.4)	(48.2)	25,768	0	(15.6)	25,752
1990	27,281	29.0	(69.4)	(201.9)	27,038	0	(27.2)	27,011
1991	28,387	48.7	(101.5)	(403.2)	27,931	0	(39.0)	27,892
1992	29,534	71.0	(131.4)	(436.5)	29,037	0	(52.2)	28,985
1993	30,456	93.2	(161.1)	(447.7)	29,940	0	(52.3)	29,888
1994	31,138	115.1	(190.1)	(447.8)	30,615	0	(52.3)	30,563
1995	31,935	137.3	(219.6)	(458.7)	31,394	0	(52.3)	31,341
1996	32,799	159.7	(249.4)	(564.8)	32,145	0	(52.4)	32,092
1997	33,457	181.4	(278.3)	(580.8)	32,779	0	(52.4)	32,727
1998	34,251	203.6	(307.7)	(585.8)	33,561	0	(52.5)	33,509
1999	35,215	226.3	(338.1)	(602.6)	34,501	0	(52.6)	34,448
2000	36,152	249.1	(368.4)	(677.6)	35,355	0	(52.6)	35,302
2001	37,180	271.7	(396.2)	(689.4)	36,366	0	(52.7)	36,313
2002	38,237	294.4	(428.9)	(690.5)	37,412	0	(52.8)	37,359
2003	39,162	316.8	(458.6)	(707.3)	38,313	0	(52.9)	38,260
2004	40,259	339.9	(489.4)	(708.4)	39,401	0	(52.9)	39,348
2005	41,545	363.8	(521.4)	(720.6)	40,667	0	(53.1)	40,613
2006	42,652	387.0	(552.2)	(721.6)	41,766	0	(53.1)	41,712
2007	43,924	410.7	(583.8)	(722.8)	43,028	0	(53.2)	42,975
2008	45,234	434.6	(615.8)	(724.1)	44,328	0	(53.3)	44,275

* This is the official forecast approved by the Forecast Review Board

FORECAST OF PROGRAM IMPACTS ON INDUSTRIAL ENERGY SALES
(GWH)

		DEMAND SIDE PROGRAMS				SUPPLY SIDE OPTIONS		
YEAR	BASE INDUSTRIAL SALES FORECAST	SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL INDUSTRIAL SALES FORECAST*	LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	INDUSTRIAL FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	4,357	0	0	(8.1)	4,349	0	(2.6)	4,347
1990	4,600	0	0	(34.1)	4,566	0	(4.6)	4,562
1991	4,755	0	0	(67.6)	4,688	0	(6.5)	4,681
1992	4,916	0	0	(72.7)	4,843	0	(8.7)	4,834
1993	5,019	0	0	(73.8)	4,946	0	(8.6)	4,937
1994	5,123	0	0	(73.7)	5,049	0	(8.6)	5,041
1995	5,226	0	0	(75.1)	5,151	0	(8.6)	5,143
1996	5,319	0	0	(91.6)	5,228	0	(8.5)	5,219
1997	5,412	0	0	(94.0)	5,318	0	(8.5)	5,309
1998	5,503	0	0	(94.1)	5,409	0	(8.4)	5,401
1999	5,594	0	0	(95.7)	5,499	0	(8.3)	5,490
2000	5,685	0	0	(106.5)	5,578	0	(8.3)	5,570
2001	5,774	0	0	(107.0)	5,667	0	(8.2)	5,658
2002	5,863	0	0	(105.9)	5,757	0	(8.1)	5,749
2003	5,953	0	0	(107.5)	5,845	0	(8.0)	5,837
2004	6,047	0	0	(106.4)	5,940	0	(8.0)	5,932
2005	6,143	0	0	(106.5)	6,036	0	(7.8)	6,028
2006	6,239	0	0	(105.5)	6,133	0	(7.8)	6,125
2007	6,335	0	0	(104.3)	6,231	0	(7.7)	6,223
2008	6,433	0	0	(103.0)	6,330	0	(7.6)	6,323

* This is the official forecast approved by the Forecast Review Board

FORECAST OF
SALES AND CUSTOMERS BY DIVISION

SALES (gWh)

	1989	% SHARE	1990	% SHARE	1991	% SHARE	1992	% SHARE
SOUTHERN	19,012	30.1	19,725	29.8	20,174	29.6	20,701	29.4
SOUTHEASTERN	13,210	20.9	13,859	21.0	14,317	21.0	14,839	21.1
EASTERN	12,570	19.9	13,215	20.0	13,682	20.1	14,152	20.1
WESTERN	9,224	14.6	9,727	14.7	10,059	14.8	10,439	14.8
NORTHEASTERN	9,175	14.5	9,617	14.5	9,875	14.5	10,176	14.5
TOTAL	63,191		66,142		68,106		70,307	

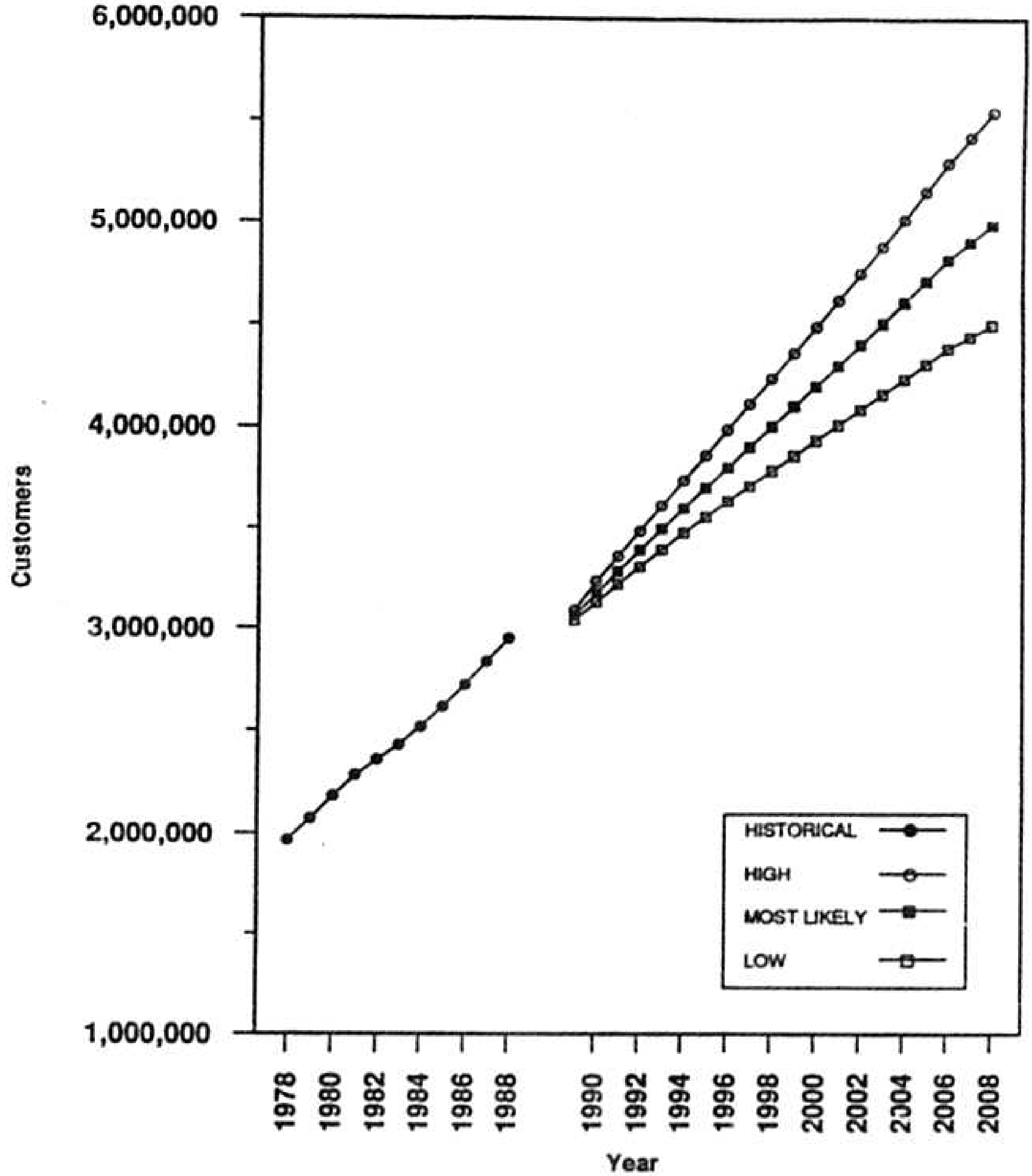
CUSTOMERS

	1989	% SHARE	1990	% SHARE	1991	% SHARE	1992	% SHARE
SOUTHERN	783,532	25.5	803,323	25.2	821,325	25.0	838,872	24.7
SOUTHEASTERN	673,974	22.0	694,593	21.8	712,573	21.7	729,304	21.5
EASTERN	626,943	20.4	659,397	20.7	691,149	21.0	723,405	21.3
WESTERN	546,596	17.8	571,989	18.0	596,394	18.1	620,989	18.3
NORTHEASTERN	436,260	14.2	453,704	14.3	469,800	14.3	485,273	14.3
TOTAL	3,067,305		3,183,006		3,291,241		3,397,843	

CUSTOMER FORECAST

- 1978 - 1988 Historical Customers By Class
- 1989 - 2008 Customer Forecast By Class

AVERAGE TOTAL CUSTOMERS



DIVISION LOAD AT TIME OF SYSTEM SUMMER PEAK
HISTORY AND FORECAST
EASTERN DIVISION
(60 Minute Net)

YEAR	PEAK (MW)	ANNUAL % CHANGE	% SYSTEM TOTAL PEAK
1978	1,131	3.2	13.6
1979	1,243	9.9	14.4
1980	1,417	14.0	14.7
1981	1,373	-3.1	14.1
1982	1,575	14.7	16.0
1983	1,678	6.5	15.7
1984	1,664	-0.8	16.2
1985	1,955	17.5	18.3
1986	2,121	8.5	19.2
1987	2,413	13.8	19.5
1988	2,427	0.6	19.6

Compound Average Annual Growth Rate
1978 through 1988 7.9%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	2,540	4.7	2,605	7.3	2,690	10.9
1990	2,670	5.1	2,750	5.6	2,842	5.6
1991	2,759	3.3	2,852	3.7	2,958	4.1
1992	2,862	3.7	2,978	4.4	3,107	5.1
1993	2,945	2.9	3,079	3.4	3,227	3.9
1994	3,011	2.3	3,164	2.8	3,331	3.2
1995	3,082	2.3	3,254	2.8	3,441	3.3
1996	3,134	1.7	3,325	2.2	3,532	2.6
1997	3,188	1.7	3,398	2.2	3,624	2.6
1998	3,255	2.1	3,486	2.6	3,734	3.0
1999	3,332	2.4	3,585	2.8	3,856	3.3
2000	3,398	2.0	3,674	2.5	3,968	2.9
2001	3,465	2.0	3,764	2.4	4,082	2.9
2002	3,532	1.9	3,855	2.4	4,198	2.8
2003	3,589	1.6	3,935	2.1	4,302	2.5
2004	3,685	2.7	4,060	3.2	4,456	3.6
2005	3,767	2.2	4,170	2.7	4,595	3.1
2006	3,835	1.8	4,264	2.3	4,716	2.6
2007	3,899	1.7	4,355	2.1	4,834	2.5
2008	4,008	2.8	4,496	3.2	5,009	3.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1996	3.0%	3.7%	4.4%
1988-2008	2.5%	3.1%	3.7%

DIVISION LOAD AT TIME OF SYSTEM SUMMER PEAK
HISTORY AND FORECAST
WESTERN DIVISION
(60 Minute Net)

YEAR	PEAK (MW)	ANNUAL % CHANGE	% SYSTEM TOTAL PEAK
1978	1,278	10.0	15.3
1979	1,343	5.1	15.5
1980	1,525	13.6	15.8
1981	1,601	5.0	16.4
1982	1,659	3.6	16.8
1983	1,746	5.2	16.4
1984	1,740	-0.3	16.9
1985	1,521	-12.6	14.3
1986	1,582	4.0	14.4
1987	1,979	25.1	16.0
1988	1,898	-4.1	15.3

Compound Average Annual Growth Rate
1978 through 1988 4.0%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	1,953	2.9	2,015	6.2	2,081	9.6
1990	1,992	2.0	2,052	1.8	2,121	1.9
1991	2,005	0.7	2,083	1.5	2,160	1.8
1992	2,044	1.9	2,127	2.1	2,219	2.8
1993	2,068	1.2	2,162	1.6	2,266	2.1
1994	2,099	1.5	2,205	2.0	2,322	2.4
1995	2,126	1.3	2,245	1.8	2,374	2.3
1996	2,143	0.8	2,273	1.2	2,414	1.7
1997	2,166	1.1	2,309	1.6	2,463	2.0
1998	2,184	0.8	2,339	1.3	2,505	1.7
1999	2,210	1.2	2,378	1.7	2,558	2.1
2000	2,224	0.6	2,404	1.1	2,597	1.5
2001	2,242	0.8	2,435	1.3	2,641	1.7
2002	2,270	1.2	2,477	1.7	2,697	2.1
2003	2,287	0.8	2,508	1.3	2,742	1.7
2004	2,308	0.9	2,543	1.4	2,791	1.8
2005	2,334	1.1	2,584	1.6	2,847	2.0
2006	2,358	1.0	2,622	1.5	2,900	1.8
2007	2,373	0.6	2,650	1.1	2,942	1.4
2008	2,380	0.3	2,670	0.8	2,975	1.1

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.4%	2.1%	2.8%
1988-2008	1.1%	1.7%	2.3%

DIVISION LOAD AT TIME OF SYSTEM SUMMER PEAK
HISTORY AND FORECAST
NORTHEASTERN DIVISION
(60 Minute Net)

YEAR	PEAK (MW)	ANNUAL % CHANGE	% SYSTEM TOTAL PEAK
1978	1346	1.7	16.1
1979	1350	0.3	15.6
1980	1581	17.1	16.4
1981	1659	4.9	17.0
1982	1568	-5.5	15.9
1983	1881	20.0	17.6
1984	1786	-5.1	17.4
1985	1917	7.3	18.0
1986	1874	-2.2	17.0
1987	2045	9.1	16.5
1988	2075	1.5	16.8

Compound Average Annual Growth Rate
1978 through 1988 4.4%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	2,103	1.4	2,170	4.6	2,241	8.0
1990	2,153	2.4	2,218	2.2	2,292	2.3
1991	2,190	1.7	2,264	2.1	2,348	2.4
1992	2,243	2.4	2,334	3.1	2,435	3.7
1993	2,297	2.4	2,402	2.9	2,518	3.4
1994	2,344	2.0	2,463	2.5	2,593	3.0
1995	2,397	2.3	2,531	2.8	2,677	3.2
1996	2,436	1.6	2,584	2.1	2,745	2.5
1997	2,478	1.7	2,641	2.2	2,817	2.6
1998	2,524	1.9	2,703	2.3	2,895	2.8
1999	2,571	1.8	2,766	2.3	2,975	2.8
2000	2,615	1.7	2,827	2.2	3,053	2.6
2001	2,657	1.6	2,886	2.1	3,130	2.5
2002	2,701	1.7	2,948	2.1	3,210	2.6
2003	2,744	1.6	3,009	2.1	3,290	2.5
2004	2,790	1.7	3,074	2.2	3,374	2.6
2005	2,839	1.8	3,143	2.2	3,463	2.7
2006	2,884	1.6	3,207	2.0	3,547	2.4
2007	2,917	1.1	3,258	1.6	3,617	2.0
2008	2,950	1.1	3,309	1.6	3,687	1.9

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988 1998	2.0%	2.7%	3.4%
1988-2008	1.8%	2.4%	2.9%

FORECAST OF PROGRAM IMPACTS ON SUMMER PEAK
(MW)

		DEMAND SIDE PROGRAMS				SUPPLY SIDE OPTIONS		
YEAR	BASE SUMMER PEAK FORECAST	SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL SUMMER PEAK FORECAST*	LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	SUMMER PEAK FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	13,001	N/A	(27.3)	(11.7)	12,962	(30)	(100)	12,832
1990	13,444	4.0	(47.2)	(59.8)	13,341	(76)	(175)	13,090
1991	13,767	7.6	(67.1)	(94.1)	13,613	(145)	(250)	13,218
1992	14,109	11.0	(83.7)	(94.1)	13,942	(226)	(335)	13,381
1993	14,537	14.2	(100.1)	(96.1)	14,355	(308)	(335)	13,712
1994	14,876	17.5	(116.6)	(96.1)	14,681	(399)	(335)	13,947
1995	15,303	20.8	(133.1)	(98.3)	15,092	(500)	(335)	14,257
1996	15,667	24.2	(149.7)	(120.3)	15,421	(605)	(335)	14,481
1997	15,994	27.5	(166.2)	(123.7)	15,732	(663)	(335)	14,734
1998	16,380	30.8	(182.8)	(123.7)	16,104	(667)	(335)	15,102
1999	16,791	34.1	(199.3)	(127.0)	16,499	(667)	(335)	15,497
2000	17,191	37.4	(215.9)	(142.4)	16,870	(667)	(335)	15,868
2001	17,568	40.7	(232.4)	(144.6)	17,232	(667)	(335)	16,230
2002	17,959	44.0	(249.0)	(144.6)	17,609	(667)	(335)	16,607
2003	18,317	47.3	(265.5)	(147.9)	17,951	(667)	(335)	16,949
2004	18,721	50.6	(282.1)	(147.9)	18,342	(667)	(335)	17,340
2005	19,188	53.9	(298.6)	(150.1)	18,793	(667)	(335)	17,791
2006	19,577	57.3	(315.2)	(150.1)	19,169	(667)	(335)	18,1[illegible]7
2007	19,914	60.6	(331.7)	(150.1)	19,493	(667)	(335)	18,491
2008	20,250	63.9	(348.2)	(150.1)	19,815	(667)	(335)	18,813

* This is the official forecast approved by the Forecast Review Board

FORECAST OF PROGRAM IMPACTS ON WINTER PEAK
(MW)

		DEMAND SIDE PROGRAMS				SUPPLY SIDE OPTIONS		
YEAR	BASE WINTER PEAK FORECAST	SALES PROGRAMS (+)	CON-SERVATION (-)	CO-GENERATION (-)	OFFICIAL WINTER PEAK FORECAST*	LOAD CONTROL (-)	INTER-RUPTIBLE RATES (-)	WINTER PEAK FORECAST W/ADJ. FOR SUPPLY & DEMAND
1989	13,051	N/A	N/A	N/A	13,051	(47.0)	(128.0)	12,876
1990	13,602	4.0	(33.2)	(54.3)	13,518	(105.0)	(175.0)	13,238
1991	14,115	7.6	(64.2)	(88.6)	13,970	(185.0)	(250.0)	13,535
1992	14,634	11.0	(92.9)	(88.6)	14,463	(267.0)	(335.0)	13,861
1993	15,177	14.2	(121.3)	(90.6)	14,979	(348.0)	(335.0)	14,296
1994	15,736	17.5	(150.0)	(90.6)	15,513	(450.0)	(335.0)	14,728
1995	16,313	20.8	(178.7)	(92.8)	16,062	(551.0)	(335.0)	15,176
1996	16,881	24.2	(207.4)	(114.8)	16,583	(660.0)	(335.0)	15,588
1997	17,388	27.5	(236.1)	(118.1)	17,061	(667.0)	(335.0)	16,059
1998	17,905	30.8	(264.7)	(120.3)	17,551	(667.0)	(335.0)	16,549
1999	18,434	34.1	(293.4)	(123.7)	18,051	(667.0)	(335.0)	17,049
2000	18,976	37.4	(322.1)	(139.1)	18,552	(667.0)	(335.0)	17,550
2001	19,523	40.7	(350.8)	(141.3)	19,072	(667.0)	(335.0)	18,070
2002	20,043	44.0	(379.5)	(141.3)	19,566	(667.0)	(335.0)	18,564
2003	20,574	47.3	(408.1)	(144.6)	20,069	(667.0)	(335.0)	19,067
2004	21,118	50.6	(436.8)	(144.6)	20,587	(667.0)	(335.0)	19,585
2005	21,675	53.9	(465.5)	(146.8)	21,117	(667.0)	(335.0)	20,115
2006	22,240	57.3	(494.2)	(146.8)	21,656	(667.0)	(335.0)	20,654
2007	22,787	60.6	(522.9)	(146.8)	22,178	(667.0)	(335.0)	21 176
2008	23,228	63.9	(551.6)	(146.8)	22,593	(667.0)	(335.0)	21,591

* This is the official forecast approved by the Forecast Review Board

MONTHLY SALES, CUSTOMERS AND USE BY CLASS

- 1988 Monthly Actual Sales, Customers And Use By Class
- 1989-1992 Monthly Forecast Of Sales, Customers And Use By Class

1988 MONTHLY HISTORICAL
SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (MWh)													
Residential	2,163,221	2,336,198	2,140,591	2,072,622	2,084,020	2,534,007	3,004,880	3,045,541	3,369,853	2,983,896	2,184,660	2,163,559	30,083,049
Commercial	1,739,990	1,712,968	1,696,771	1,881,732	1,860,640	2,082,356	2,189,709	2,185,891	2,348,997	2,280,132	2,002,617	1,929,878	23,911,681
Industrial	325,801	331,325	340,659	351,066	334,695	352,769	344,179	332,484	365,130	369,083	343,352	341,106	4,131,648
Street & Highway	25,575	25,973	25,819	25,440	24,699	25,800	26,400	25,980	26,128	26,196	26,078	26,261	310,350
Other	47,011	46,285	45,806	54,085	48,226	55,717	66,638	58,736	66,626	55,163	53,884	52,620	650,796
Railroads & Railways	6,589	6,035	6,074	6,530	5,943	6,284	6,657	6,225	6,616	6,663	5,778	5,921	75,316
TOTAL JURISDICTIONAL SALES	4,308,187	4,458,784	4,255,722	4,391,475	4,358,223	5,056,933	5,638,463	5,654,857	6,183,350	5,721,132	4,616,369	4,519,345	59,162,840
Resale	51,997	56,404	52,762	52,569	54,089	53,939	65,125	69,734	78,147	75,349	60,341	58,740	729,197
TOTAL SALES	4,360,184	4,515,189	4,308,484	4,444,044	4,412,312	5,110,872	5,703,588	5,724,591	6,261,497	5,796,480	4,676,711	4,578,085	59,892,036
SYSTEM CUSTOMERS													Average
Residential	2,599,157	2,614,510	2,623,410	2,616,450	2,597,909	2,594,657	2,598,918	2,605,240	2,613,637	2,626,115	2,650,701	2,676,357	2,618,088
Commercial	307,817	309,143	310,719	311,991	313,037	314,100	314,828	315,664	316,811	318,060	319,444	320,677	314,358
Industrial	18,207	18,023	17,905	17,865	17,803	17,721	17,688	17,719	17,873	18,097	18,106	18,063	17,923
Street & Highway	2,801	2,827	2,855	2,883	2,918	2,934	2,953	2,961	2,977	2,981	3,017	3,042	2,929
Other	334	334	332	331	330	329	329	328	328	328	328	328	330
Railroads & Railways	22	22	22	22	22	22	22	22	22	22	22	22	22
TOTAL JURISDICTIONAL CUSTOMERS	2,928,338	2,944,859	2,955,243	2,949,542	2,932,019	2,929,763	2,934,738	2,941,934	2,951,648	2,965,603	2,991,618	3,018,489	2,953,650
Resale	14	14	14	14	14	14	14	14	14	13	13	13	14
TOTAL CUSTOMERS	2,928,352	2,944,873	2,955,257	2,949,556	2,932,033	2,929,777	2,934,752	2,941,948	2,951,662	2,965,616	2,991,631	3,018,502	2,953,663
USE PER CUSTOMER (kWh)													
Residential	832	894	816	792	802	977	1,156	1,169	1,289	1,136	824	808	11,491
Commercial	5,653	5,541	5,461	6,031	5,944	6,630	6,955	6,925	7,415	7,169	6,269	6,018	76,065
Industrial	17,894	18,383	19,026	19,651	18,800	19,907	19,458	18,764	20,429	20,395	18,963	18,884	230,529
Street & Highway	9,131	9,188	9,043	8,824	8,464	8,794	8,940	8,774	8,777	8,788	8,644	8,633	105,955
Other	140,752	138,578	137,971	163,399	146,139	169,352	202,548	179,072	203,128	168,179	164,280	160,426	1,970,617
Railroads & Railways	299,494	274,315	276,111	296,825	270,151	285,632	302,590	282,958	300,715	302,857	262,655	269,154	3,423,454
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,471	1,514	1,440	1,489	1,486	1,726	1,921	1,922	2,095	1,929	1,543	1,497	20,031
Resale	3,714,095	4,028,889	3,768,736	3,754,920	3,863,498	3,852,779	4,651,781	4,981,008	5,581,951	5,796,046	4,641,639	4,518,[illegible]44	53,032,498
TOTAL USE PER CUSTOMER	1,489	1,533	1,458	1,507	1,505	1,744	1,943	1,946	2,121	1,955	1,563	1,517	20,277

1989 MONTHLY FORECAST
SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	2,238,030	2,085,898	2,402,735	2,185,793	2,348,380	2,679,622	3,161,058	3,178,299	3,271,894	3,071,676	2,280,685	2,331,967	31,236,037
Commercial	1,876,829	1,935,703	1,926,305	1,993,155	2,070,734	2,252,090	2,373,019	2,329,459	2,344,986	2,415,022	2,134,637	2,116,042	25,767,981
Industrial	326,955	369,979	351,375	347,694	362,669	370,873	376,565	370,278	348,549	373,305	370,148	380,867	4,349,258
Street & Highway	26,564	26,458	26,586	26,791	26,605	26,666	26,727	26,788	26,849	26,910	26,971	27,032	320,945
Other	50,300	52,627	54,569	51,415	53,730	59,478	69,333	61,289	63,562	57,796	55,654	55,335	685,087
Railroads & Railways	6,565	6,514	6,859	6,069	6,800	6,800	6,851	6,701	6,801	6,800	6,800	6,801	80,359
TOTAL JURISDICTIONAL SALES	4,525,243	4,477,179	4,768,429	4,610,917	4,868,917	5,395,528	6,013,552	5,972,813	6,062,641	5,951,508	4,874,895	4,918,044	62,439,667
Resale	56,257	56,000	59,413	69,062	54,939	58,032	63,810	70,258	65,895	71,320	60,235	66,447	751,667
TOTAL SALES	4,581,500	4,533,179	4,827,842	4,679,979	4,923,857	5,453,560	6,077,362	6,043,071	6,128,536	6,022,828	4,935,130	4,984,490	63,191,334
													Average
SYSTEM CUSTOMERS													
Residential	2,697,300	2,711,694	2,722,001	2,716,562	2,697,850	2,689,741	2,694,244	2,700,901	2,709,524	2,720,444	2,746,991	2,772,848	2,715,008
Commercial	321,961	323,156	324,293	325,401	326,128	331,552	332,321	333,203	335,469	335,732	337,193	338,495	330,409
Industrial	17,956	17,977	17,925	17,806	17,604	18,566	18,531	18,563	18,753	18,959	18,969	18,895	18,375
Street & Highway	3,038	3,070	3,092	3,113	3,135	3,141	3,159	3,176	3,193	3,210	3,227	3,244	3,150
Other	327	326	325	325	325	330	330	329	329	329	329	329	328
Railroads & Railways	22	22	22	22	22	22	22	22	22	22	22	22	22
TOTAL JURISDICTIONAL CUSTOMERS	3,040,604	3,056,245	3,067,658	3,063,229	3,045,064	3,043,352	3,048,606	3,056,194	3,067,290	3,078,697	3,106,730	3,133,833	3,067,292
Resale	13	13	13	13	13	13	13	13	13	13	13	13	13
TOTAL CUSTOMERS	3,040,617	3,056,258	3,067,671	3,063,242	3,045,077	3,043,365	3,048,619	3,056,207	3,067,303	3,078,710	3,106,743	3,133,846	3,067,305
USE PER CUSTOMER (kWh)													
Residential	830	769	883	805	870	996	1,173	1,177	1,208	1,129	830	841	11,511
Commercial	5,829	5,990	5,940	6,125	6,349	6,793	7,141	6,991	6,990	7,193	6,331	6,251	77,924
Industrial	18,209	20,581	19,603	19,527	20,602	19,976	20,321	19,947	18,586	19,690	19,513	20,156	236,710
Street & Highway	8,744	8,618	8,598	8,606	8,486	8,488	8,462	8,435	8,409	8,384	8,358	8,333	101,923
Other	153,823	161,433	167,905	158,200	165,323	180,358	210,243	186,416	193,330	175,794	169,278	168,307	2,090,410
Railroads & Railways	298,409	296,091	311,773	275,864	309,091	309,091	311,386	304,582	309,114	309,091	309,091	309,114	3,652,695
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,488	1,465	1,554	1,505	1,599	1,773	1,973	1,954	1,977	1,933	1,569	1,569	20,360
Resale	4,327,462	4,307,692	4,570,231	5,312,462	4,226,102	4,463,981	4,908,434	5,404,460	5,068,836	5,486,127	4,633,498	5,111,273	57,820,558
TOTAL USE PER CUSTOMER	1,507	1,483	1,574	1,528	1,617	1,792	1,993	1,977	1,998	1,956	1,589	1,591	20,605

1990 MONTHLY FORECAST
SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	2,541,871	2,252,627	2,444,811	2,268,691	2,415,384	2,775,570	3,260,968	3,283,367	3,397,082	3,216,554	2,407,378	2,434,137	32,698,439
Commercial	2,133,877	2,015,349	1,979,550	2,081,173	2,157,081	2,341,911	2,451,788	2,412,791	2,442,102	2,539,226	2,263,466	2,220,060	27,038,372
Industrial	396,193	369,028	366,207	370,920	379,068	382,972	385,031	379,142	359,900	389,670	390,041	398,066	4,566,239
Street & Highway	27,094	27,155	27,217	27,279	27,340	27,402	27,463	27,525	27,586	27,648	27,709	27,771	329,189
Other	55,631	53,166	53,898	53,057	54,391	59,863	69,479	61,575	64,276	59,029	57,356	56,440	698,161
Railroads & Railways	6,800	6,700	6,701	6,851	6,800	6,800	6,851	6,701	6,801	6,800	6,800	6,801	81,403
TOTAL JURISDICTIONAL SALES	5,161,466	4,724,026	4,878,383	4,807,970	5,040,063	5,594,517	6,201,580	6,171,100	6,297,746	6,238,927	5,152,750	5,143,274	65,411,803
Resale	73,047	54,050	55,497	46,930	53,277	56,062	62,862	69,399	64,666	70,310	58,965	64,936	730,001
TOTAL SALES	5,234,514	4,778,077	4,933,880	4,854,899	5,093,340	5,650,580	6,264,442	6,240,499	6,362,412	6,309,237	5,211,715	5,208,209	66,141,804
													Average
SYSTEM CUSTOMERS													
Residential	2,793,906	2,808,686	2,818,942	2,812,361	2,793,945	2,790,689	2,795,462	2,802,449	2,811,392	2,822,650	2,849,535	2,875,732	2,814,646
Commercial	338,769	339,517	340,711	341,875	342,125	345,832	346,634	347,554	349,918	350,192	351,716	353,073	345,660
Industrial	18,922	18,944	18,889	18,764	18,551	18,921	18,886	18,919	19,083	19,322	19,332	19,286	18,985
Street & Highway	3,263	3,280	3,297	3,314	3,331	3,348	3,365	3,382	3,399	3,417	3,434	3,451	3,357
Other	324	324	324	324	324	324	324	324	324	324	324	324	324
Railroads & Railways	22	22	22	22	22	22	22	22	22	22	22	22	22
TOTAL JURISDICTIONAL CUSTOMERS	3,155,206	3,170,773	3,182,186	3,176,661	3,158,299	3,159,136	3,164,693	3,172,651	3,184,139	3,195,927	3,224,363	3,251,888	3,182,993
Resale	12	12	12	12	12	12	12	12	12	12	12	12	12
TOTAL CUSTOMERS	3,155,218	3,170,785	3,182,198	3,176,673	3,158,311	3,159,148	3,164,705	3,172,663	3,184,151	3,195,939	3,224,375	3,251,900	3,183,006
USE PER CUSTOMER (kWh)													
Residential	910	802	867	807	865	995	1,167	1,172	1,208	1,140	845	846	11,622
Commercial	6,299	5,936	5,810	6,088	6,305	6,772	7,073	6,942	6,979	7,251	6,435	6,288	78,178
Industrial	20,938	19,480	19,387	19,768	20,434	20,241	20,387	20,040	18,859	20,167	20,176	20,640	240,518
Street & Highway	8,304	8,279	8,255	8,231	8,207	8,184	8,161	8,138	8,115	8,092	8,070	8,048	98,083
Other	171,608	163,947	166,120	163,538	167,656	184,534	214,193	189,834	198,176	182,015	176,868	174,056	2,152,545
Railroads & Railways	309,091	304,545	304,568	311,386	309,091	309,091	311,386	304,582	309,114	309,091	309,091	309,114	3,700,150
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,636	1,490	1,533	1,514	1,596	1,771	1,960	1,945	1,978	1,952	1,598	1,582	20,553
Resale	6,087,258	4,504,199	4,624,749	3,910,799	4,439,744	4,671,857	5,238,523	5,783,280	5,388,838	5,859,136	4,913,769	5,411,297	60,833,449
TOTAL USE PER CUSTOMER	1,659	1,507	1,550	1,528	1,613	1,789	1,979	1,967	1,998	1,974	1,616	1,602	20,783

1991 MONTHLY FORECAST
SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	2,629,098	2,326,304	2,521,688	2,331,321	2,495,122	2,847,644	3,335,542	3,371,791	3,479,732	3,313,015	2,470,925	2,513,928	33,636,111
Commercial	2,214,338	2,088,712	2,049,474	2,147,007	2,237,258	2,412,599	2,518,316	2,488,225	2,512,164	2,626,583	2,333,224	2,302,756	27,930,656
Industrial	409,722	380,785	377,346	380,353	390,049	391,171	392,056	387,565	367,374	400,515	399,830	410,952	4,687,717
Street & Highway	27,835	27,899	27,963	28,027	28,091	28,155	28,219	28,283	28,347	28,412	28,476	28,540	338,246
Other	56,262	53,711	54,403	53,369	55,009	60,140	69,598	61,931	64,488	59,555	57,668	57,103	703,236
Railroads & Railways	6,850	6,850	6,800	6,850	6,800	6,800	6,850	6,701	6,801	6,800	6,800	6,801	81,702
TOTAL JURISDICTIONAL SALES	5,344,105	4,884,261	5,037,673	4,946,927	5,212,329	5,746,510	6,350,582	6,344,496	6,458,906	6,434,879	5,296,923	5,320,079	67,377,669
Resale	72,989	53,782	54,334	45,925	52,428	54,975	63,753	70,449	65,804	70,262	58,914	64,782	728,397
TOTAL SALES	5,417,094	4,938,043	5,092,008	4,992,851	5,264,757	5,801,485	6,414,335	6,414,945	6,524,709	6,505,141	5,355,837	5,384,861	68,106,066
													Average
SYSTEM CUSTOMERS													
Residential	2,884,282	2,899,332	2,909,878	2,903,666	2,885,665	2,882,751	2,887,829	2,895,111	2,904,339	2,915,870	2,942,962	2,969,363	2,906,754
Commercial	353,558	354,092	355,137	356,551	356,562	360,678	361,514	362,474	364,939	365,956	366,815	367,494	360,499
Industrial	20,006	20,029	19,971	19,839	19,614	20,005	19,968	20,003	20,176	20,429	20,439	20,391	20,072
Street & Highway	3,468	3,485	3,502	3,519	3,536	3,553	3,570	3,587	3,604	3,622	3,639	3,656	3,562
Other	321	321	321	321	321	321	321	321	321	321	321	321	321
Railroads & Railways	22	22	22	22	22	22	22	22	22	22	22	22	22
TOTAL JURISDICTIONAL CUSTOMERS	3,261,657	3,277,281	3,289,031	3,283,918	3,265,720	3,267,330	3,273,224	3,281,518	3,293,402	3,306,220	3,334,197	3,361,247	3,291,229
Resale	11	11	11	11	11	11	11	11	11	11	11	11	11
TOTAL CUSTOMERS	3,261,668	3,277,292	3,289,042	3,283,929	3,265,731	3,267,341	3,273,235	3,281,529	3,293,413	3,306,231	3,334,208	3,361,258	3,291,241
USE PER CUSTOMER (kWh)													
Residential	912	802	867	803	865	988	1,155	1,165	1,198	1,136	840	847	11,576
Commercial	6,263	5,899	5,768	6,022	6,275	6,689	6,966	6,865	6,884	7,177	6,361	6,266	77,433
Industrial	20,480	19,011	18,894	19,172	19,887	19,554	19,635	19,376	18,208	19,605	19,562	20,154	233,538
Street & Highway	8,027	8,006	7,985	7,964	7,944	7,924	7,904	7,884	7,864	7,845	7,826	7,807	94,979
Other	175,152	167,217	167,379	166,174	171,292	187,285	216,756	192,893	200,874	185,524	179,659	177,911	2,190,115
Railroads & Railways	311,364	311,364	309,091	311,364	309,091	309,091	311,364	304,582	309,114	309,091	309,091	309,114	3,713,718
TOTAL JURISDICTIONAL USE PER CUSTOMERS	1,638	1,490	1,532	1,506	1,596	1,759	1,940	1,933	1,961	1,946	1,589	1,583	20,474
Resale	6,635,403	4,889,278	4,939,486	4,174,984	4,766,200	4,997,721	5,795,714	6,404,453	5,982,152	6,387,445	5,355,799	5,889,268	66,217,903
TOTAL USE PER CUSTOMER	1,661	1,507	1,548	1,520	1,612	1,776	1,960	1,955	1,981	1,968	1,606	1,602	20,695

1992 MONTHLY FORECAST
SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
SYSTEM SALES (mWh)													
Residential	2,707,209	2,482,558	2,586,931	2,396,740	2,559,940	2,906,153	3,430,884	3,447,709	3,550,675	3,403,705	2,527,515	2,586,295	34,586,316
Commercial	2,304,516	2,252,879	2,125,041	2,230,942	2,320,032	2,488,636	2,618,163	2,571,635	2,590,990	2,727,564	2,412,395	2,394,603	29,037,395
Industrial	424,490	408,660	389,002	392,615	401,392	400,149	404,188	397,287	376,031	413,131	410,927	424,980	4,842,852
Street & Highway	28,604	28,668	28,732	28,796	28,860	28,924	28,988	29,053	29,117	29,181	29,245	29,309	347,477
Other	56,745	56,144	54,668	53,746	55,286	60,125	70,130	62,037	64,466	59,944	57,793	57,556	708,639
Railroads & Railways	6,850	6,850	6,800	6,850	6,800	6,800	6,851	6,701	6,801	6,800	6,800	6,801	81,702
TOTAL JURISDICTIONAL SALES	5,528,414	5,235,759	5,191,175	5,109,690	5,372,310	5,890,787	6,559,204	6,514,422	6,618,079	6,640,325	5,444,675	5,499,543	69,604,382
Resale	70,373	51,854	52,386	44,278	50,549	53,004	61,467	67,923	63,444	67,743	56,802	62,459	702,282
TOTAL SALES	5,598,787	5,287,612	5,243,561	5,153,968	5,422,859	5,943,791	6,620,671	6,582,345	6,681,524	6,708,068	5,501,477	5,562,002	70,306,664
													Average
SYSTEM CUSTOMERS													
Residential	2,973,877	2,989,158	2,999,962	2,994,110	2,976,534	2,973,955	2,979,325	2,986,887	2,996,385	3,008,175	3,035,439	3,062,015	2,997,985
Commercial	367,596	368,188	369,483	370,745	370,793	375,036	375,906	376,904	379,467	380,524	381,417	382,123	374,850
Industrial	20,821	20,846	20,785	20,647	20,413	20,820	20,781	20,818	20,999	21,262	21,273	21,222	20,891
Street & Highway	3,673	3,690	3,707	3,724	3,741	3,758	3,775	3,792	3,809	3,827	3,844	3,861	3,767
Other	318	318	318	318	318	318	318	318	318	318	318	318	318
Railroads & Railways	22	22	22	22	22	22	22	22	22	22	22	22	22
TOTAL JURISDICTIONAL CUSTOMERS	3,366,308	3,382,221	3,394,277	3,389,567	3,371,822	3,373,910	3,380,127	3,388,741	3,401,000	3,414,128	3,442,313	3,469,561	3,397,831
Resale	11	11	11	11	11	11	11	11	11	11	11	11	11
TOTAL CUSTOMERS	3,366,319	3,382,232	3,394,288	3,389,578	3,371,833	3,373,921	3,380,138	3,388,752	3,401,011	3,414,139	3,442,324	3,469,572	3,397,843
USE PER CUSTOMER (kWh)													
Residential	910	831	862	800	860	977	1,152	1,154	1,185	1,131	833	845	11,541
Commercial	6,269	6,119	5,751	6,017	6,257	6,636	6,965	6,823	6,828	7,168	6,325	6,267	77,425
Industrial	20,387	19,604	18,715	19,015	19,663	19,219	19,449	19,084	17,907	19,430	19,317	20,025	231,818
Street & Highway	7,788	7,769	7,751	7,732	7,714	7,696	7,678	7,661	7,643	7,626	7,609	7,592	92,259
Other	178,429	176,553	171,927	169,038	173,896	189,130	220,620	195,178	202,835	188,621	181,867	181,137	2,229,234
Railroads & Railways	311,364	311,364	309,091	311,364	309,091	309,091	311,386	304,582	309,114	309,091	309,091	309,114	3,713,741
TOTAL JURISDICTIONAL CUSTOMERS	1,642	1,548	1,529	1,507	1,593	1,746	1,941	1,922	1,946	1,945	1,582	1,585	2[illegible],487
Resale	6,397,507	4,713,984	4,762,393	4,025,300	4,595,319	4,818,540	5,587,923	6,174,836	5,767,677	6,158,438	5,163,779	5,678,122	63,843,818
TOTAL USE PER CUSTOMER	1,663	1,563	1,545	1,521	1,608	1,762	1,959	1,942	1,965	1,965	1,598	1,603	20,694

MONTHLY SYSTEM NET ENERGY FOR LOAD FORECASTS

- 1966 - 1988 System Monthly Net Energy For Load
- 1989 - 2008 System Monthly Net Energy For Load

HISTORY OF SYSTEM MONTHLY NET ENERGY FOR LOAD
(gWh)

Year	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec	For The Year
1966	1,130	1,082	1,095	1,093	1,185	1,309	1,441	1,548	1,508	1,343	1,134	1,190	15,058
1967	1,207	1,130	1,263	1,273	1,333	1,496	1,633	1,677	1,679	1,349	1,284	1,316	16,640
1968	1,390	1,378	1,439	1,438	1,510	1,695	1,826	2,056	1,911	1,661	1,478	1,565	19,347
1969	1,540	1,437	1,625	1,605	1,715	2,138	2,294	2,325	2,210	2,009	1,647	1,671	22,216
1970	1,904	1,647	1,717	1,964	1,910	2,270	2,443	2,701	2,659	2,196	1,909	1,793	25,113
1971	2,017	1,826	1,983	2,019	2,319	2,529	2,766	2,882	2,766	2,561	2,120	2,094	27,882
1972	2,171	2,076	2,144	2,381	2,428	2,865	3,070	3,308	3,195	2,764	2,590	2,507	31,499
1973	2,532	2,425	2,528	2,558	2,762	3,410	3,404	3,597	3,615	3,084	2,727	2,543	35,185
1974	2,490	2,309	2,714	2,736	2,974	3,400	3,394	3,695	3,863	2,738	2,597	2,555	35,465
1975	2,656	2,470	2,762	2,953	3,195	3,563	3,381	3,832	3,627	3,169	2,848	2,695	37,151
1976	2,957	2,720	2,806	2,834	3,051	3,313	3,771	3,883	3,736	3,089	2,983	2,972	38,115
1977	3,492	2,879	3,102	3,038	3,006	3,916	4,028	4,072	3,951	3,143	2,984	3,101	40,712
1978	3,344	3,313	3,078	3,124	3,575	4,165	4,253	4,375	4,342	3,523	3,358	3,255	43,705
1979	3,363	3,238	3,239	3,456	3,511	4,412	4,577	4,621	4,462	3,729	3,471	3,263	45,342
1980	3,459	3,538	3,697	3,572	3,787	4,521	4,695	5,009	4,762	4,118	3,791	3,501	48,449
1981	4,566	3,353	3,487	3,779	3,920	4,949	4,942	4,915	4,624	4,097	3,606	3,784	50,022
1982	3,956	3,324	3,839	4,025	3,781	4,746	5,038	5,171	4,988	4,094	3,804	3,766	50,532
1983	4,085	3,503	3,836	3,778	4,134	4,799	5,350	5,370	5,166	4,543	3,849	4,087	52,500
1984	4,397	3,796	4,155	4,043	4,472	4,762	4,996	5,399	4,995	4,286	4,003	3,844	53,148
1985	4,456	3,830	4,017	4,041	4,479	5,482	4,993	5,641	5,239	5,027	4,535	4,258	55,998
1986	4,313	3,886	4,395	4,070	4,472	5,323	5,448	5,894	5,857	5,183	5,104	4,322	58,267
1987	4,659	4,052	4,411	4,459	4,934	6,036	6,139	6,648	6,266	4,836	4,758	4,417	61,616
1988	4,858	4,567	4,712	4,972	5,043	5,919	6,149	6,538	6,717	5,316	5,158	4,767	64,716

FORECAST OF SYSTEM MONTHLY NET ENERGY FOR LOAD

(gWh)

Year	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec	For The Year
1989	4,909	4,719	5,246	5,368	5,349	6,282	6,557	6,871	6,595	5,613	5,429	5,163	68,101
1990	5,528	4,971	5,385	5,562	5,590	6,525	6,759	7,096	6,843	5,877	5,730	5,392	71,259
1991	5,720	5,137	5,559	5,721	5,779	6,701	6,921	7,294	7,016	6,059	5,888	5,574	73,370
1992	5,914	5,500	5,725	5,904	5,953	6,866	7,146	7,487	7,187	6,249	6,046	5,757	75,732
1993	6,065	5,641	5,872	6,056	6,105	7,042	7,329	7,679	7,371	6,409	6,201	5,904	77,676
1994	6,184	5,653	6,000	6,188	6,238	7,231	7,504	7,880	7,574	6,550	6,355	6,023	79,380
1995	6,335	5,814	6,142	6,332	6,387	7,391	7,674	8,059	7,741	6,705	6,497	6,169	81,246
1996	6,478	5,977	6,276	6,473	6,527	7,550	7,848	8,235	7,907	6,854	6,637	6,307	83,068
1997	6,611	6,088	6,407	6,608	6,663	7,712	8,015	8,413	8,079	6,997	6,778	6,437	84,808
1998	6,758	6,207	6,551	6,756	6,813	7,893	8,200	8,611	8,269	7,155	6,933	6,580	86,727
1999	6,921	6,365	6,707	6,917	6,976	8,081	8,398	8,819	8,467	7,327	7,098	6,738	88,814
2000	7,074	6,509	6,854	7,070	7,130	8,261	8,588	9,018	8,656	7,490	7,254	6,887	90,791
2001	7,256	6,671	7,031	7,253	7,314	8,478	8,813	9,256	8,884	7,684	7,442	7,063	93,144
2002	7,442	6,839	7,210	7,438	7,501	8,698	9,042	9,498	9,116	7,881	7,633	7,244	95,545
2003	7,612	6,997	7,375	7,608	7,673	8,900	9,252	9,720	9,328	8,063	7,808	7,409	97,746
2004	7,800	7,169	7,557	7,797	7,863	9,122	9,485	9,965	9,563	8,263	8,001	7,592	100,177
2005	8,010	7,359	7,759	8,006	8,074	9,371	9,744	10,238	9,824	8,486	8,217	7,795	102,881
2006	8,204	7,537	7,947	8,200	8,270	9,601	9,984	10,493	10,067	8,693	8,416	7,984	105,396
2007	8,420	7,735	8,156	8,416	8,488	9,857	10,252	10,775	10,336	8,923	8,639	8,194	108,190
2008	8,641	7,936	8,369	8,636	8,710	10,119	10,524	11,063	10,612	9,157	8,865	8,408	111,040

WEEKLY NET ENERGY FOR LOAD

- Forecast Of Monthly Net Energy Allocated On A Weekly Basis For 1990

FORECAST OF MONTHLY NET ENERGY FOR LOAD ALLOCATED ON A WEEKLY BASIS
(MWH)

1990

JANUARY

04-Jan-90	1,215,485
11-Jan-90	1,272,466
18-Jan-90	1,334,898
25-Jan-90	1,191,802

FEBRUARY

01-Feb-90	1,214,584
08-Feb-90	1,233,485
15-Feb-90	1,331,526
22-Feb-90	1,206,416

MARCH

01-Mar-90	1,198,847
08-Mar-90	1,198,702
15-Mar-90	1,217,003
22-Mar-90	1,227,054
29-Mar-90	1,221,822

APRIL

05-Apr-90	1,312,324
12-Apr-90	1,209,701
19-Apr-90	1,279,502
26-Apr-90	1,240,440

MAY

03-May-90	1,238,424
10-May-90	1,227,887
17-May-90	1,303,755
24-May-90	1,388,144
31-May-90	1,376,963

JUNE

07-Jun-90	1,400,342
14-Jun-90	1,441,665
21-Jun-90	1,526,057
28-Jun-90	1,552,454

JULY

05-Jul-90	1,520,389
12-Jul-90	1,627,569
19-Jul-90	1,565,865
26-Jul-90	1,574,091

AUGUST

02-Aug-90	1,608,080
09-Aug-90	1,554,653
16-Aug-90	1,659,201
23-Aug-90	1,607,129
30-Aug-90	1,604,283

SEPTEMBER

06-Sep-89	1,581,536
13-Sep-89	1,622,027
20-Sep-89	1,557,156
27-Sep-90	1,408,100

OCTOBER

04-Oct-90	1,464,972
11-Oct-90	1,459,442
18-Oct-90	1,354,542
25-Oct-90	1,294,629

NOVEMBER

01-Nov-90	1,279,648
08-Nov-90	1,340,605
15-Nov-90	1,240,284
22-Nov-90	1,309,128
29-Nov-90	1,259,116

DECEMBER

06-Dec-90	1,245,592
13-Dec-90	1,235,916
20-Dec-90	1,244,039
27-Dec-90	1,313,092

MONTHLY SYSTEM PEAK LOADS

- 1966 - 1988 System Monthly Peak Loads
- 1989 - 2008 System Monthly Peak Loads

HISTORY SYSTEM MONTHLY PEAK LOADS INCLUDING QUALIFYING FACILITIES

(60 Minute Net in mW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	For The Year
1966	2,693	2,914	2,335	2,190	2,351	2,488	2,722	2,803	2,827	2,820	2,432	2,589	2,914
1967	2,672	2,823	2,883	2,608	2,803	3,000	3,114	3,144	3,160	2,728	2,698	2,905	3,160
1968	3,178	3,247	3,318	2,937	3,059	3,388	3,577	3,789	3,737	3,404	3,242	3,751	3,789
1969	3,104	3,433	3,354	3,318	3,506	4,244	4,311	4,329	4,153	3,992	3,462	3,549	4,329
1970	4,716	4,322	3,378	4,022	3,956	4,486	4,723	4,902	5,001	4,339	4,459	3,888	5,001
1971	5,059	4,653	4,026	4,686	4,749	5,089	5,348	5,378	5,285	5,366	4,816	4,478	5,378
1972	4,366	4,676	4,220	4,951	5,006	5,847	6,011	5,992	5,977	5,836	5,354	5,371	6,011
1973	5,307	5,853	5,212	5,141	5,960	6,443	6,760	6,721	6,894	6,384	5,858	5,851	6,894
1974	4,748	5,506	6,258	5,492	5,980	6,497	6,770	6,973	7,235	6,292	5,300	5,426	7,235
1975	5,807	5,420	5,472	5,933	6,210	6,988	6,658	7,076	6,778	6,738	5,720	6,810	7,076
1976	7,287	6,310	5,388	5,455	6,159	6,476	7,598	7,225	7,307	7,139	6,173	6,295	7,598
1977	8,606	7,352	6,433	6,160	6,385	7,780	7,841	7,603	7,613	7,266	5,931	7,404	8,606
1978	8,037	8,617	6,122	6,183	7,405	7,973	8,184	8,316	8,345	7,677	6,650	7,002	8,617
1979	8,110	8,791	6,605	6,601	7,045	8,432	8,650	8,636	8,373	7,606	7,133	6,472	8,791
1980	7,669	9,218	9,732	7,354	8,042	8,753	9,623	9,356	9,136	9,049	8,625	8,153	9,732
1981	10,738	9,786	6,280	7,241	8,061	9,638	9,738	9,409	8,996	8,134	7,667	9,574	10,738
1982	10,919	7,038	7,388	8,013	7,612	9,337	9,501	9,893	9,814	8,366	7,744	7,683	10,919
1983	9,280	8,600	7,932	7,303	8,649	9,172	10,676	10,155	10,331	8,961	7,573	10,384	10,676
1984	9,385	9,953	9,533	8,027	9,266	9,542	9,840	10,270	9,830	8,058	8,738	7,641	10,270
1985	12,533	10,253	7,454	7,518	9,235	10,654	10,274	10,314	9,944	9,545	8,903	10,839	12,533
1986	12,139	11,880	9,973	7,888	9,196	10,259	10,884	11,022	10,824	10,771	9,635	8,994	12,139
1987	10,779	10,571	8,117	8,699	9,495	11,490	11,914	12,394	12,273	10,311	9,667	9,376	12,394
1988	12,372	10,269	10,289	10,598	11,197	11,716	12,201	12,382	12,216	11,287	10,242	11,475	12,382

FORECAST SYSTEM MONTHLY PEAK LOADS INCLUDING QUALIFYING FACILITIES

(60 Minute Net in mW)

Year	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec	For The Year
1989	8,993	12,876	11,092	10,449	11,147	12,443	12,832	12,962	12,832	11,795	10,544	11,423	12,962
1990	13,518	12,572	10,950	10,406	11,473	12,807	13,208	13,341	13,208	12,140	10,897	11,805	13,518
1991	13,970	12,992	11,316	10,618	11,707	13,068	13,477	13,613	13,477	12,388	11,281	12,221	13,970
1992	14,463	13,451	11,715	10,875	11,990	13,384	13,803	13,942	13,803	12,687	11,684	12,657	14,463
1993	14,979	13,930	12,133	11,197	12,345	13,781	14,211	14,355	14,211	13,063	12,100	13,108	14,979
1994	15,513	14,427	12,566	11,451	12,626	14,094	14,534	14,681	14,534	13,360	12,528	13,572	15,513
1995	16,062	14,938	13,010	11,772	12,979	14,488	14,941	15,092	14,941	13,734	12,935	14,013	16,062
1996	16,583	15,422	13,432	12,028	13,262	14,804	15,267	15,421	15,267	14,033	13,308	14,417	16,583
1997	17,061	15,867	13,819	12,271	13,530	15,103	15,575	15,732	15,575	14,316	13,690	14,831	17,061
1998	17,551	16,322	14,216	12,561	13,849	15,460	15,943	16,104	15,943	14,655	14,080	15,253	17,551
1999	18,051	16,787	14,621	12,869	14,189	15,839	16,334	16,499	16,334	15,014	14,471	15,676	18,051
2000	18,552	17,253	15,027	13,159	14,508	16,195	16,701	16,870	16,701	15,352	14,876	16,116	18,552
2001	19,072	17,737	15,448	13,441	14,820	16,543	17,060	17,232	17,060	15,681	15,261	16,533	19,072
2002	19,566	18,196	15,848	13,735	15,144	16,905	17,433	17,609	17,433	16,024	15,654	16,958	19,566
2003	20,069	18,664	16,256	14,002	15,438	17,233	17,771	17,951	17,771	16,335	16,058	17,396	20,069
2004	20,587	19,146	16,675	14,307	15,774	17,608	18,159	18,342	18,159	16,691	16,471	17,844	20,587
2005	21,117	19,639	17,105	14,659	16,162	18,041	18,605	18,793	18,605	17,102	16,892	18,299	21,117
2006	21,656	20,140	17,541	14,952	16,485	18,402	18,977	19,169	18,977	17,444	17,299	18,740	21,656
2007	22,178	20,626	17,964	15,205	16,764	18,713	19,298	19,493	19,298	17,739	17,623	19,091	22,178
2008	22,593	21,011	18,300	15,456	17,041	19,022	19,617	19,815	19,617	18,032	17,952	19,448	22,593

EXHIBIT NO. 4

DOCKET NO.: 960409-EI

WITNESS: WATERS

DESCRIPTION: CHARLES BLACK PRESENTATION REGARDING ECONOMIC JUSTIFICATION FOR IGCC

Ex. 33

2.3 A Utility's Perspective of the Market for IGCC

CONTRACT INFORMATION

Cooperative Agreement	DE-FC21-91MC27363
Contractor	Tampa Electric Company P.O. Box 111, Tampa FL 33601 (813) 228-1767
Contractor Project Manager	Charles R. Black
Principal Investigators	Charles R. Black
METC Project Manager	Nelson F. Rekos, Jr.
Period of Performance	January 1, 1996 to December 31, 1997

INTRODUCTION

I would like to discuss our utility's view of the Market for Integration Gasification Combined Cycle (IGCC) power plants and share with you some of the experiences we have had with our Integrated Gasification Combined Cycle Power Plant Project, Polk Unit #1.

We have found that not only is the technology different from what most U. S. utilities are accustomed to, but also that the non-technical issues or business issues, such as contracting, project management and contract administration also have different requirements. During this conference you will hear many presentations on the status of the technical issues associated with IGCC technology. Therefore, I will focus my remarks on the non-technical or business issues that are vital to the successful commercialization of this technology.

We believe these business issues must be successfully addressed by both the utilities and the technology suppliers in order for integrated gasification combined cycle power plants (IGCC) to achieve commercial success.

In order to understand some of the issues we have experienced, it will be helpful to understand how our project is configured and our current status.

PARTICIPANTS

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC serves about 470,000 Customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC owns five generating stations: two are coal-fired (2852MW) two are oil-fired (253MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

TECO Power Services (TPS) is a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS currently owns, and operates a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a twenty year power sales agreement.

TPS is responsible for the overall project management for the DOE portion of this IGCC

EXHIBIT
4
6-12-96

This will lead to the commercial operation of the CT in July 1995 and the IGCC unit in July 1996.

BUSINESS ISSUES ECONOMIC JUSTIFICATION

The first business issue any utility has to deal with in implementing a new generating addition is the issue of economic justification. The three basic driving forces in the economic justification of any technology are its fuel cost relative to other technologies, its capital cost, and its efficiency.

I believe, in the short-term U. S. market, that IGCC's primary competition is natural gas-fired combined cycle technology. I believe that in order for IGCC to compete on a commercial basis, that natural gas prices have to rise relative to coal prices, and that the capital cost of the technology must come down. While this statement may seem to be somewhat obvious, it raises two interesting points.

The first is that while the relative pricing of natural gas and coal is not generally within the technology supplier's control, the capital cost is. The reduction of capital cost represents a major challenge for the technology suppliers in order for this technology to become commercialized.

The second point is that the improvements being achieved with IGCC efficiencies probably won't help it outperform the effects of natural gas pricing. This is due to the fact that the combined cycle portion of the IGCC technology is experiencing the most significant improvements in efficiency. While certain improvements in coal gasification and integration are being made, they potentially will be overshadowed by improvements in combustion turbine/combined cycle technology. Combustion Turbine/Combined Cycle improvements will apply to natural gas-fired units as well as IGCC units. Therefore, I believe the relative efficiencies of these technologies will continue to closely track.

I do see, however, a significant advantage for IGCC technology compared to conventional pulverized coal-fired units. As IGCC efficiencies continue to improve, combined with their environmentally superior performance, I believe that IGCC will be the "technology of choice" for utilities that install new coal-fired generation.

We have achieved economic justification of our project by virtue of the DOE's funding of $120 million awarded in Round III of their Clean Coal Technology Program. This program provides the bridge between current technology economics and those of the future. And Tampa Electric is pleased to be taking a leadership position in furthering the IGCC knowledge base.

SITING

The next major issue that a utility must address after a technology decision has been made is that of siting. Siting of coal-fired generation is a major issue that must be addressed in order to commercialize IGCC or any other coal-based technology. Successful siting is a primary responsibility of the utility. For the Polk Power Station, we employed a proactive approach with local environmentalists and the local communities.

By late 1989, we had formed an independent citizen's task force made up of 17 people representing environmentalists, educators, economists and community leaders, to help guide that search.

Some of the various groups who had members on the task force were: The National Audubon Society, Florida Audubon Society, 1,000 Friends of Florida, Sierra Club, The Hillsborough Environmental Coalition, and others. We made sure that at least half of the group was comprised of environmentalists. We knew that protecting the environment would be the number one priority in selecting the plant's technology and site.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that one true and correct copy of the Deposition Transcript and Exhibits of Mr. Samuel S. Waters 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:

Florida Industrial Power
Users Group
Vicki Kaufman, Esquire
117 South Gadsden Street
Tallahassee, FL 32301

McWhirter Reeves McGlothlin
Davidson Rief & Bakas
John W. McWhirter, Esquire
Post Office Box 3350
Tampa, FL 33601-3350

Office of Public Counsel
John Roger Howe, Esquire
c/o The Florida Legislature
111 W. Madison Street
Tallahassee, FL 32399-1400

Tampa Electric Company
Ms. Jana Hathorne *
Regulatory Affairs Department
Post Office Box 111
Tampa, FL 33601-0111

* Furnished to Mr. Willis by hand delivery.

Robert V. Elias

ROBERT V. ELIAS
Chief, Bureau Electric and Gas

Florida Public Service Commission
2540 Shumard Oak Boulevard
Gerald L. Gunter
Tallahassee, Florida 32399-0850
(904) 413-6199

ORIGINAL
FILE COPY

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

WITNESS: SAMUEL S. WATERS

DESCRIPTION: DEPOSITION OF SAMUEL S. WATERS PLUS EXHIBITS SUBMITTED FOR FILING BY THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION

DATE FILED: JUNE 14, 1996

ACK ______
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CMU ______
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EAG ______
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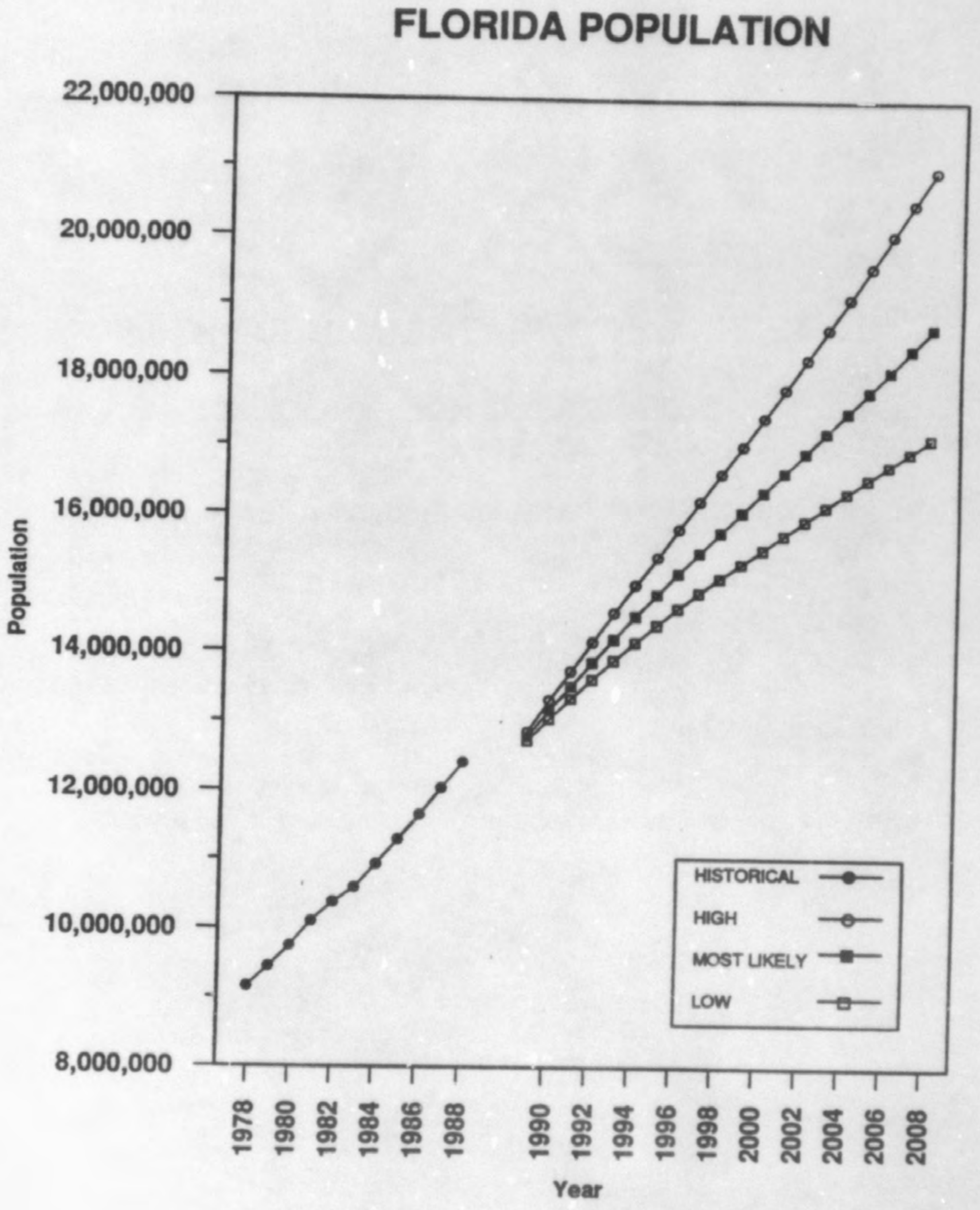
SEC 1
WAS ______
OTH ______

DOCUMENT NUMBER-DATE
06473 JUN 14 96
FPSC-RECORDS/REPORTING

ECONOMETRIC AND WEATHER ASSUMPTIONS

HISTORY AND FORECAST OF :

- Population Of Florida And FPL Service Territory
- Population In FPL Service Territory Per Residential Customer
- Residential Air Conditioning And Electric Heating Saturations
- Temperatures For Summer/Winter Peak Values


FLORIDA POPULATION
22,000,000
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
Population
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
Year
HISTORICAL
HIGH
MOST LIKELY
LOW

FLORIDA POPULATION
HISTORY AND FORECAST

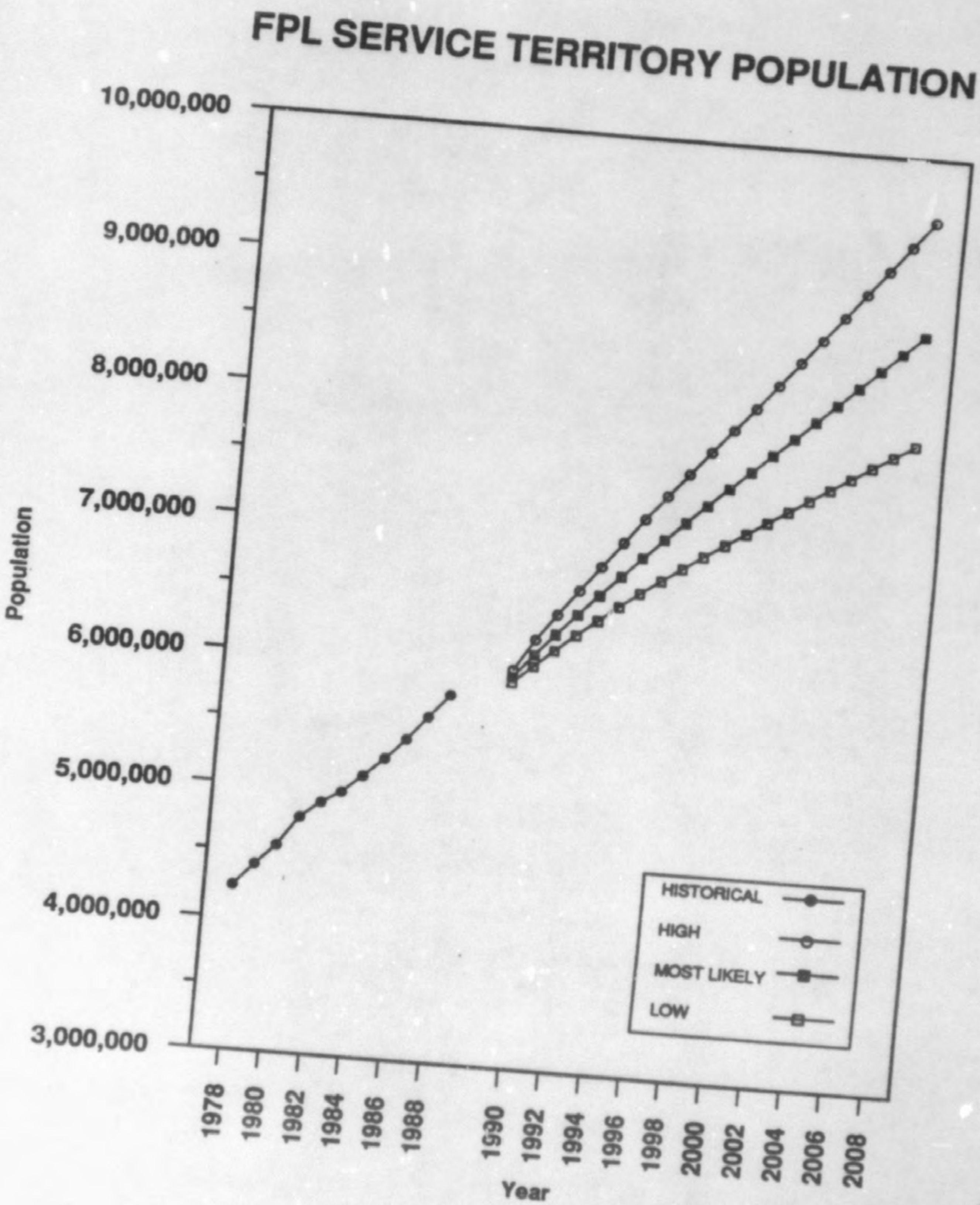
YEAR	POPULATION	ANNUAL INCREASE	ANNUAL % CHANGE
1978	9,156,700	236,700	2.7
1979	9,448,500	291,800	3.2
1980	9,746,324	297,824	3.2
1981	10,105,957	359,633	3.7
1982	10,375,332	269,375	2.7
1983	10,591,701	216,369	2.1
1984	10,930,389	338,688	3.2
1985	11,287,932	357,543	3.3
1986	11,657,843	369,911	3.3
1987	12,043,608	385,765	3.3
1988	12,417,600	373,992	3.1

Compound Average Annual Growth Rate
1978 through 1988 3.1%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	12,733,452	2.5	12,793,766	3.0	12,865,598	3.6
1990	13,057,338	2.5	13,181,328	3.0	13,329,759	3.6
1991	13,352,209	2.3	13,531,858	2.7	13,748,413	3.1
1992	13,635,291	2.1	13,874,379	2.5	14,164,573	3.0
1993	13,906,488	2.0	14,208,770	2.4	14,578,221	2.9
1994	14,165,511	1.9	14,534,708	2.3	14,989,129	2.8
1995	14,412,220	1.7	14,852,008	2.2	15,397,201	2.7
1996	14,648,765	1.6	15,160,985	2.1	15,805,071	2.6
1997	14,875,155	1.5	15,462,776	2.0	16,211,092	2.6
1998	15,093,458	1.5	15,759,475	1.9	16,617,510	2.5
1999	15,306,251	1.4	16,053,743	1.9	17,027,221	2.5
2000	15,515,530	1.4	16,347,678	1.8	17,442,588	2.4
2001	15,727,204	1.4	16,642,420	1.8	17,859,374	2.4
2002	15,936,851	1.3	16,938,296	1.8	18,283,479	2.4
2003	16,144,285	1.3	17,235,131	1.8	18,714,883	2.4
2004	16,349,198	1.3	17,532,619	1.7	19,153,425	2.3
2005	16,551,475	1.2	17,830,655	1.7	19,599,162	2.3
2006	16,751,700	1.2	18,129,457	1.7	20,054,985	2.3
2007	16,950,145	1.2	18,429,631	1.7	20,519,210	2.3
2008	17,149,012	1.2	18,732,194	1.6	20,990,342	2.3

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.0%	2.4%	3.0%
1988-2008	1.6%	2.1%	2.7%


FPL SERVICE TERRITORY POPULATION
10,000,000
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
Population
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
Year
HISTORICAL
HIGH
MOST LIKELY
LOW

FPL SERVICE TERRITORY POPULATION
HISTORY AND FORECAST

YEAR	POPULATION	ANNUAL INCREASE	% ANNUAL CHANGE
1978	4,242,056	121,731	3.0
1979	4,402,354	160,298	3.8
1980	4,553,449	151,095	3.4
1981	4,770,489	217,040	4.8
1982	4,893,954	123,465	2.6
1983	4,982,368	88,414	1.8
1984	5,110,379	128,011	2.6
1985	5,252,701	142,322	2.8
1986	5,405,716	153,015	2.9
1987	5,579,773	174,057	3.2
1988	5,760,259	180,486	3.2

Compound Average Annual Growth Rate
1978 through 1988 3.1%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	5,891,157	2.3	5,934,755	3.0	5,988,522	4.0
1990	6,025,973	2.3	6,114,536	3.0	6,226,830	4.0
1991	6,155,844	2.2	6,276,474	2.6	6,420,981	3.1
1992	6,281,062	2.0	6,435,210	2.5	6,613,344	3.0
1993	6,401,441	1.9	6,590,504	2.4	6,803,625	2.9
1994	6,516,712	1.8	6,742,026	2.3	6,991,432	2.8
1995	6,626,694	1.7	6,889,529	2.2	7,176,453	2.6
1996	6,733,013	1.6	7,033,050	2.1	7,357,162	2.5
1997	6,834,722	1.5	7,173,077	2.0	7,535,461	2.4
1998	6,932,834	1.4	7,310,627	1.9	7,712,374	2.3
1999	7,028,642	1.4	7,447,033	1.9	7,889,280	2.3
2000	7,123,144	1.3	7,583,338	1.8	8,067,270	2.3
2001	7,217,639	1.3	7,720,087	1.8	8,246,148	2.2
2002	7,311,545	1.3	7,857,400	1.8	8,426,728	2.2
2003	7,404,726	1.3	7,995,142	1.8	8,608,873	2.2
2004	7,496,998	1.2	8,133,118	1.7	8,792,379	2.1
2005	7,588,294	1.2	8,271,259	1.7	8,977,172	2.1
2006	7,681,156	1.2	8,409,678	1.7	9,160,977	2.0
2007	7,773,532	1.2	8,548,710	1.7	9,346,480	2.0
2008	7,866,045	1.2	8,688,924	1.6	9,534,617	2.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.8%	2.3%	2.8%
1988-2008	1.5%	2.0%	2.5%

POPULATION IN FPL SERVICE TERRITORY PER RESIDENTIAL CUSTOMER HISTORY AND FORECAST

YEAR	FPL RATIO	ANNUAL % CHANGE
1978	2.41	-1.8
1979	2.37	-1.6
1980	2.33	-1.9
1981	2.33	0.2
1982	2.32	-0.6
1983	2.30	-1.0
1984	2.27	-0.9
1985	2.25	-0.9
1986	2.23	-0.9
1987	2.21	-0.9
1988	2.20	-0.6

Compound Average Annual Growth Rate
1978 through 1988 -0.9%

YEAR	MOST LIKELY FPL RATIO *	ANNUAL % CHANGE
1989	2.19	-0.7
1990	2.17	-0.6
1991	2.16	-0.6
1992	2.15	-0.6
1993	2.13	-0.6
1994	2.12	-0.6
1995	2.11	-0.6
1996	2.10	-0.6
1997	2.09	-0.5
1998	2.08	-0.5
1999	2.06	-0.5
2000	2.05	-0.5
2001	2.04	-0.5
2002	2.03	-0.5
2003	2.02	-0.5
2004	2.01	-0.5
2005	2.00	-0.5
2006	1.99	-0.5
2007	1.99	-0.0
2008	1.99	-0.0

Compound Average Annual Growth Rate

1988-1998	-0.6%
1988-2008	-0.5%

* Also used for low and high scenarios

RESIDENTIAL AIR CONDITIONING AND ELECTRIC HEATING SATURATIONS

HISTORY

	Air Conditioning % Customers	Electric Heating % Customers
1978	83.9	62.2
1979	87.7	68.1
1980	91.4	73.9
1981	91.8	76.0
1982	92.1	78.0
1983	91.7	80.2
1984	91.3	82.3
1985	92.4	81.7
1986	93.4	81.1
1987	93.8	81.8
1988	94.1	82.4

FORECAST

	Air Conditioning % Customers	Electric Heating % Customers
1989	94.4	82.7
1990	94.7	83.0
1991	95.0	83.2
1992	95.2	83.5
1993	95.5	83.6
1994	95.7	83.8
1995	95.8	84.0
1996	95.9	84.3
1997	95.9	84.6
1998	95.9	84.8
1999	95.9	84.9
2000	95.9	85.0
2001	96.0	85.2
2002	96.2	85.4
2003	96.2	85.5
2004	96.2	85.5
2005	96.2	85.8
2006	96.2	86.0
2007	96.2	86.0
2008	96.2	86.1

SUMMER PEAK LOAD
TEMPERATURE VALUES*

Year	Temperatures
1968	92
1969	91
1970	91
1971	88
1972	91
1973	90
1974	89
1975	90
1976	91
1977	91
1978	89
1979	91
1980	93
1981	98
1982	92
1983	95
1984	93
1985	97
1986	88
1987	95
1988	93

* These annual temperatures are the sales weighted average of the maximum summer peak day temperatures for the cities of Miami, Daytona Beach, and Ft. Meyers.

WINTER PEAK LOAD TEMPERATURE VALUES*

Year	Temperatures
1968	31
1969	43
1970	34
1971	31
1972	38
1973	39
1974	40
1975	37
1976	37
1977	33
1978	33
1979	39
1980	31
1981	28
1982	28
1983	37
1984	27
1985	26
1986	30
1987	37
1988	41

* These annual temperatures are the sales weighted average of the maximum winter peak day temperatures for the cities of Miami, Daytona Beach, and Ft. Meyers.

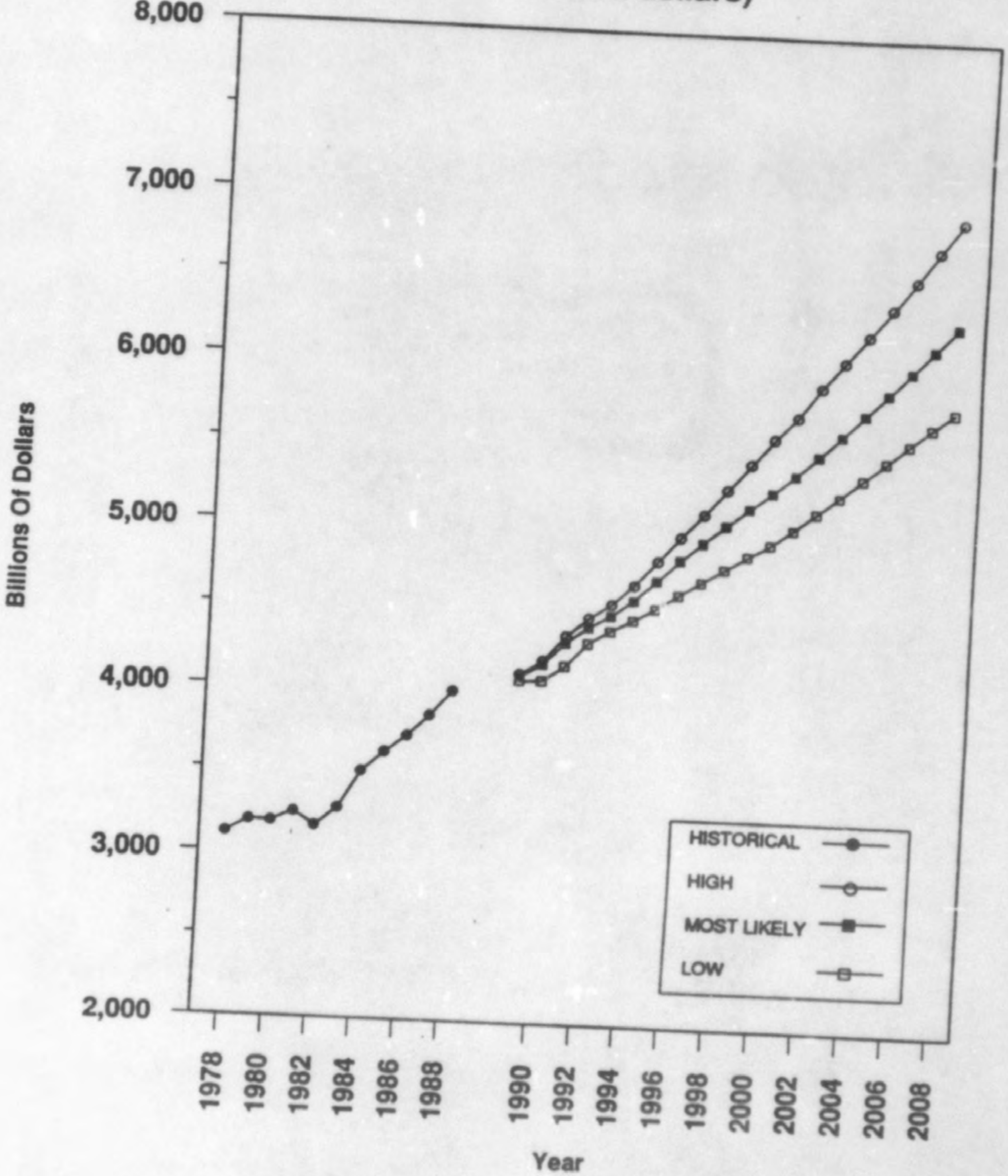
ECONOMIC ASSUMPTIONS

HISTORY AND FORECAST OF :

- Real Gross National Product And Deflator
- Consumer Price Index
- Producer Price Index : All Commodities, Capital Equipment
- Average Hourly Earnings : Non-Agricultural Business Sector
- Florida Non-Agricultural And Manufacturing Employment
- Florida Real Personal Income
- Real Average Price Of Electricity For Total Customers

REAL GROSS NATIONAL PRODUCT

(Billions of 1982 dollars)



REAL GROSS NATIONAL PRODUCT
HISTORY AND FORECAST
(Billions of 1982 Dollars)

Year	Actual	Annual % Change
1978	3,115.2	5.3
1979	3,192.4	2.5
1980	3,187.1	-0.2
1981	3,248.8	1.9
1982	3,166.0	-2.5
1983	3,279.1	3.6
1984	3,501.4	6.8
1985	3,618.7	3.4
1986	3,721.7	2.8
1987	3,847.0	3.4
1988	3,996.1	3.9

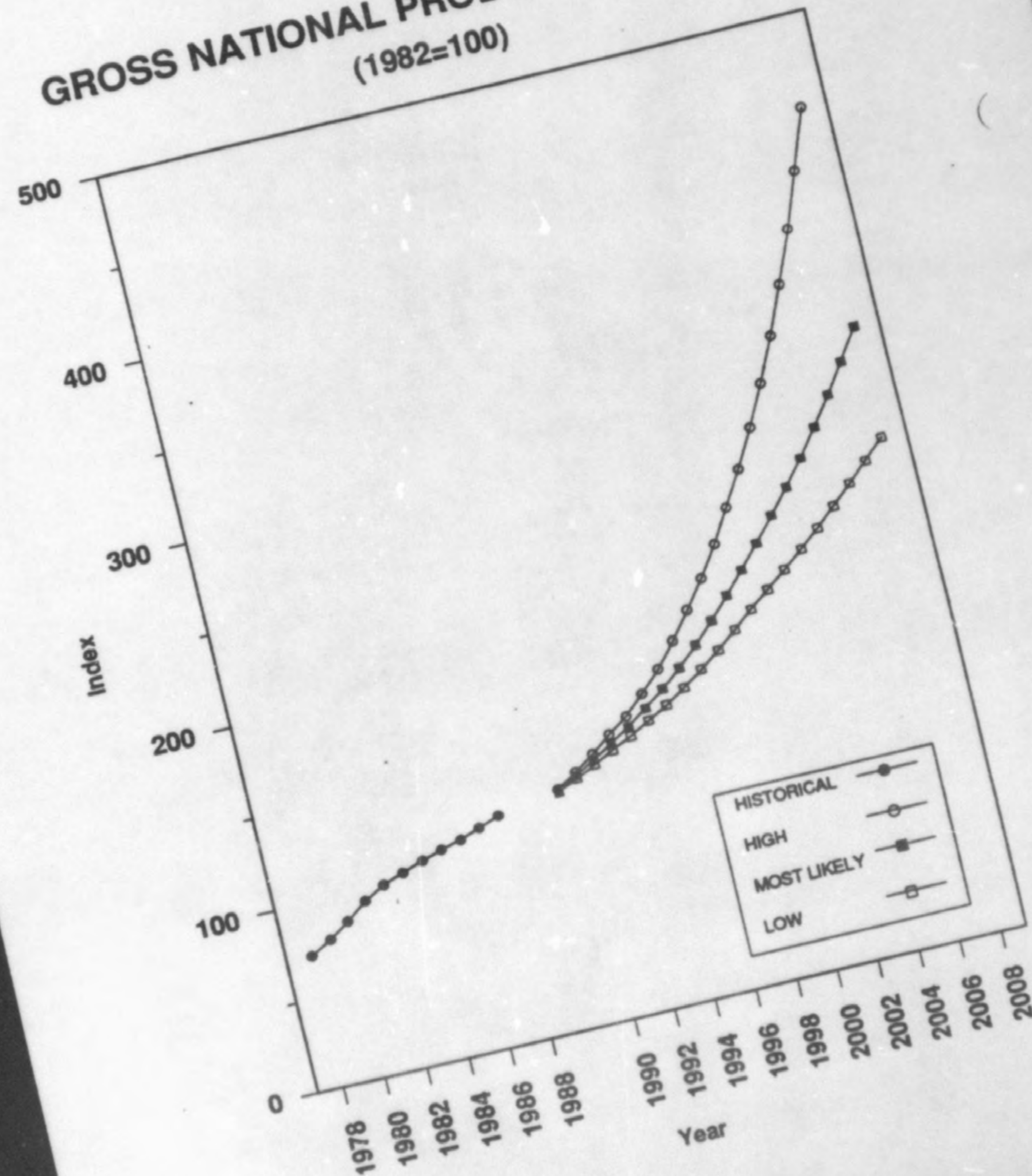
Compound Average Annual Growth Rate
1978 through 1988 2.5%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	4,070.9	1.9	4,099.0	2.6	4,111.2	2.9
1990	4,076.4	0.1	4,175.0	1.9	4,197.4	2.1
1991	4,168.3	2.3	4,308.0	3.2	4,346.5	3.6
1992	4,308.4	3.4	4,406.0	2.3	4,464.8	2.7
1993	4,388.4	1.9	4,481.0	1.7	4,554.6	2.0
1994	4,457.6	1.6	4,581.0	2.2	4,677.1	2.7
1995	4,536.0	1.8	4,708.0	2.8	4,827.4	3.2
1996	4,624.3	1.9	4,838.0	2.8	4,978.8	3.1
1997	4,707.3	1.8	4,947.0	2.3	5,121.0	2.9
1998	4,793.1	1.8	5,056.0	2.2	5,275.5	3.0
1999	4,876.4	1.7	5,166.0	2.2	5,435.4	3.0
2000	4,950.8	1.5	5,265.0	1.9	5,590.7	2.9
2001	5,043.8	1.9	5,376.0	2.1	5,725.9	2.4
2002	5,149.2	2.1	5,497.0	2.3	5,908.1	3.2
2003	5,253.0	2.0	5,621.0	2.3	6,064.8	2.7
2004	5,362.8	2.1	5,751.0	2.3	6,226.1	2.7
2005	5,472.8	2.1	5,882.0	2.3	6,388.5	2.6
2006	5,581.5	2.0	6,018.0	2.3	6,560.9	2.7
2007	5,682.5	1.8	6,153.0	2.2	6,742.0	2.8
2008	5,780.2	1.7	6,291.0	2.2	6,922.5	2.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.8%	2.4%	2.8%
1988-2008	1.9%	2.3%	2.8%

GROSS NATIONAL PRODUCT DEFLATOR
(1982=100)



GROSS NATIONAL PRODUCT DEFLATOR
HISTORY AND FORECAST
(1982 = 100)

Year	Actual	Annual % Change
1978	72.2	7.3
1979	78.6	8.9
1980	85.7	9.0
1981	94.0	9.7
1982	100.0	6.4
1983	103.9	3.9
1984	107.7	3.7
1985	110.9	3.0
1986	113.9	2.7
1987	117.7	3.3
1988	121.7	3.4

Compound Average Annual Growth Rate
1978 through 1988 5.4%

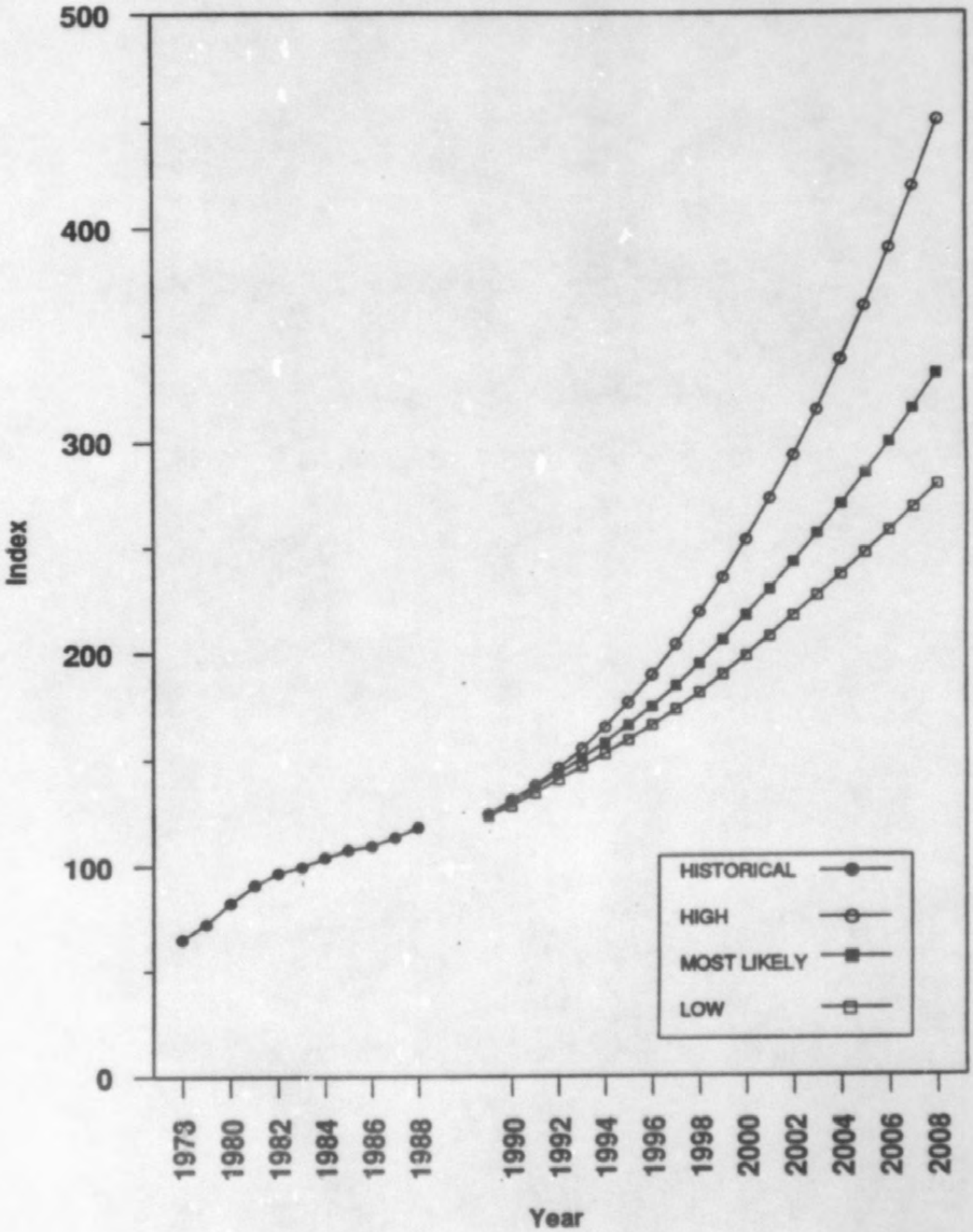
YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	126.4	3.9	127.2	4.5	128.0	5.2
1990	131.4	3.9	133.0	4.5	134.7	5.2
1991	136.4	3.8	139.0	4.5	142.1	5.5
1992	141.6	3.8	145.3	4.6	150.0	5.6
1993	146.6	3.6	151.7	4.4	157.4	4.9
1994	152.4	3.9	159.2	4.9	167.2	6.2
1995	158.3	3.9	167.3	5.1	178.1	6.5
1996	165.2	4.4	176.1	5.3	190.5	7.0
1997	172.6	4.4	185.6	5.4	204.1	7.1
1998	180.2	4.4	195.8	5.5	219.0	7.3
1999	188.4	4.5	206.8	5.6	235.3	7.4
2000	196.7	4.4	218.5	5.7	252.8	7.4
2001	204.8	4.1	230.5	5.5	271.4	7.3
2002	213.3	4.1	243.1	5.5	291.6	7.5
2003	221.9	4.0	256.1	5.3	313.2	7.4
2004	230.7	4.0	269.7	5.3	336.5	7.5
2005	240.3	4.2	283.9	5.3	361.6	7.5
2006	250.1	4.1	298.8	5.2	389.0	7.6
2007	260.1	4.0	314.4	5.2	418.5	7.6
2008	270.5	4.0	330.8	5.2	450.3	7.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	4.0%	4.9%	6.1%
1988-2008	4.1%	5.1%	6.8%

CONSUMER PRICE INDEX

(1982-1984=100)



CONSUMER PRICE INDEX
HISTORY AND FORECAST
(1982-1984 = 100)

Year	Actual	Annual % Change
1978	65.2	7.6
1979	72.6	11.3
1980	82.4	13.5
1981	90.9	10.3
1982	96.5	6.1
1983	99.6	3.2
1984	103.9	4.3
1985	107.6	3.5
1986	109.6	1.9
1987	113.6	3.7
1988	118.3	4.1

Compound Average Annual Growth Rate
1978 through 1988 6.1%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	123.4	4.3	124.1	5.0	124.5	5.2
1990	128.4	4.1	130.2	4.9	131.2	5.4
1991	134.4	4.6	136.6	4.9	137.7	5.0
1992	140.5	4.6	143.4	5.0	145.7	5.8
1993	146.6	4.3	150.5	4.9	155.0	6.4
1994	152.7	4.2	158.0	5.0	165.4	6.7
1995	159.3	4.3	166.4	5.3	177.0	7.0
1996	166.3	4.4	175.3	5.4	189.8	7.2
1997	173.8	4.5	184.8	5.4	203.8	7.4
1998	181.6	4.5	195.0	5.5	219.1	7.5
1999	190.0	4.6	206.1	5.7	235.7	7.6
2000	198.7	4.6	217.8	5.7	253.9	7.7
2001	207.8	4.6	230.2	5.7	273.2	7.6
2002	217.4	4.6	243.1	5.6	293.7	7.5
2003	227.2	4.5	256.5	5.5	315.4	7.4
2004	237.2	4.4	270.4	5.4	338.7	7.4
2005	247.4	4.3	285.0	5.4	363.8	7.4
2006	257.8	4.2	300.1	5.3	390.7	7.4
2007	268.6	4.2	316.0	5.3	419.6	7.4
2008	279.6	4.1	332.4	5.2	450.7	7.4

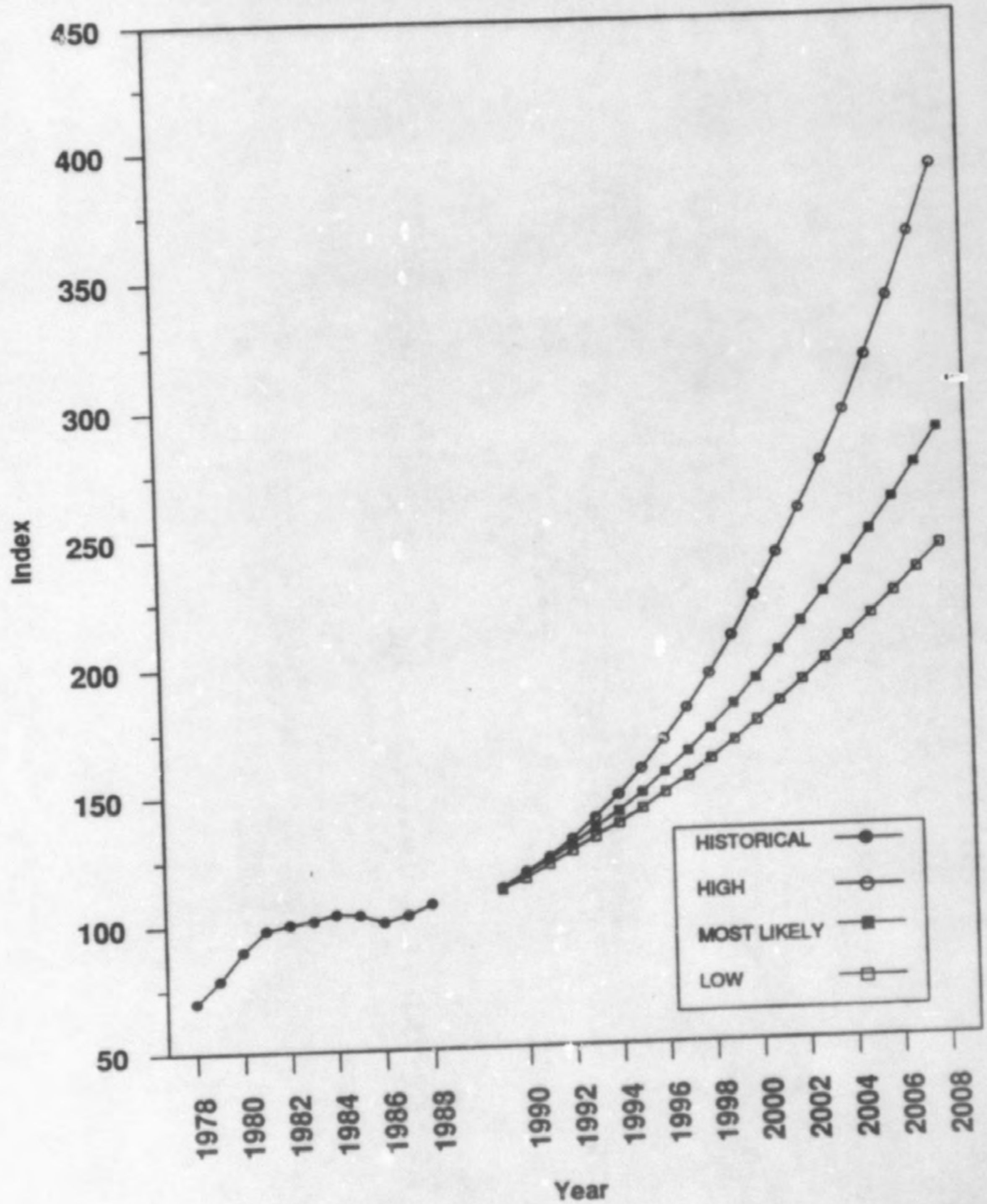
Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	4.4%	5.1%	6.4%
1988-2008	4.4%	5.3%	6.9%

PRODUCER PRICE INDEX

(All Commodities)

(1982=100)



PRODUCER PRICE INDEX
ALL COMMODITIES
HISTORY AND FORECAST
(1982 = 100)

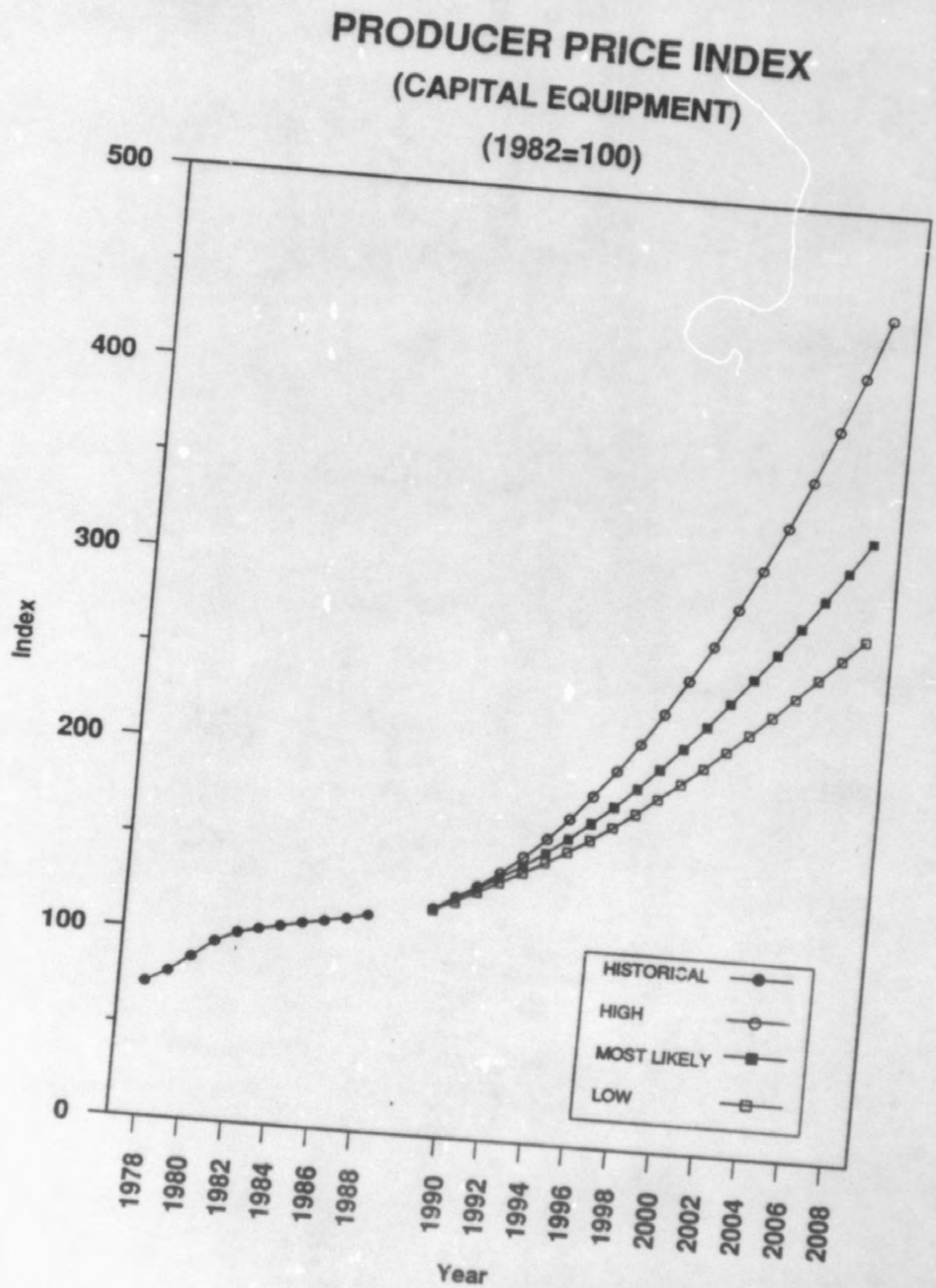
Year	Actual	Annual % Change
1978	69.9	7.7
1979	78.7	12.6
1980	89.8	14.1
1981	98.0	9.2
1982	100.0	2.0
1983	101.3	1.2
1984	103.7	2.4
1985	103.1	-0.5
1986	100.2	-2.9
1987	102.8	2.6
1988	106.9	4.0

Compound Average Annual Growth Rate 1978 through 1988 4.3%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	111.4	4.2	112.0	4.8	112.4	5.1
1990	115.7	3.9	117.3	4.7	118.2	5.2
1991	120.8	4.4	122.8	4.7	123.8	4.8
1992	126.1	4.4	128.7	4.8	130.7	5.6
1993	131.2	4.1	134.7	4.7	138.8	6.2
1994	136.4	4.0	141.1	4.8	147.8	6.5
1995	142.0	4.1	148.2	5.1	157.7	6.8
1996	147.9	4.2	155.9	5.2	168.7	6.9
1997	154.1	4.3	163.9	5.2	180.8	7.1
1998	160.7	4.2	172.5	5.2	193.8	7.2
1999	167.7	4.3	181.9	5.4	208.1	7.3
2000	175.0	4.3	191.8	5.4	223.5	7.4
2001	182.5	4.3	202.2	5.4	239.9	7.3
2002	190.5	4.3	213.0	5.3	257.3	7.2
2003	198.6	4.2	224.2	5.2	275.7	7.1
2004	206.8	4.2	235.7	5.2	295.4	7.1
2005	215.2	4.1	247.9	5.2	316.5	7.1
2006	223.7	4.0	260.4	5.1	339.1	7.2
2007	232.6	4.0	273.6	5.1	363.4	7.2
2008	241.6	3.9	287.2	5.0	389.4	7.2

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	4.2%	4.9%	6.1%
1988-2008	4.2%	5.1%	6.7%


PRODUCER PRICE INDEX
(CAPITAL EQUIPMENT)
(1982=100)
500
400
300
200
100
0
Index
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
Year
HISTORICAL
HIGH
MOST LIKELY
LOW

PRODUCER PRICE INDEX
CAPITAL EQUIPMENT
HISTORY AND FORECAST
(1982 = 100)

Year	Actual	Annual % Change
1978	71.3	7.9
1979	77.5	8.7
1980	85.8	10.7
1981	94.6	10.2
1982	100.0	5.7
1983	102.8	2.8
1984	105.2	2.4
1985	107.5	2.2
1986	109.7	2.0
1987	111.7	1.8
1988	114.3	2.4

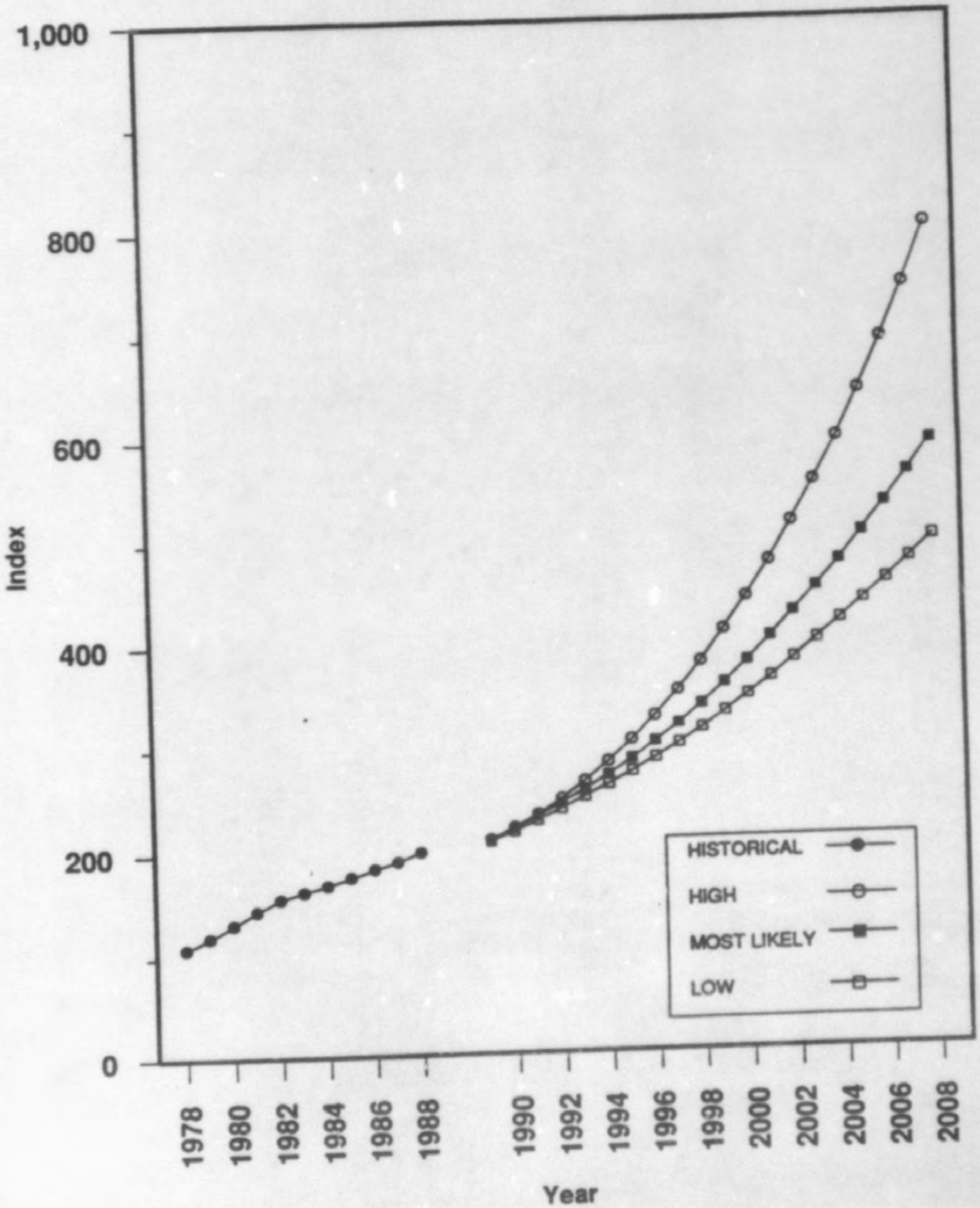
Compound Average Annual Growth Rate 4.8%
1978 through 1988

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	119.5	4.5	120.1	5.1	120.5	5.4
1990	124.5	4.2	126.2	5.0	127.1	5.5
1991	130.3	4.7	132.5	5.0	133.6	5.1
1992	136.5	4.7	139.3	5.1	141.5	5.9
1993	142.5	4.4	146.2	5.0	150.7	6.5
1994	148.6	4.3	153.7	5.1	160.9	6.8
1995	155.1	4.4	162.0	5.4	172.4	7.1
1996	162.1	4.5	170.9	5.5	185.0	7.3
1997	169.6	4.6	180.3	5.5	198.9	7.5
1998	177.4	4.6	190.5	5.6	214.0	7.6
1999	185.8	4.7	201.5	5.8	230.5	7.7
2000	194.5	4.7	213.3	5.8	248.6	7.8
2001	203.7	4.7	225.7	5.8	267.7	7.7
2002	213.3	4.7	238.5	5.7	288.1	7.6
2003	223.1	4.6	251.9	5.6	309.8	7.5
2004	233.2	4.5	265.8	5.5	333.0	7.5
2005	243.5	4.4	280.4	5.5	358.1	7.5
2006	254.0	4.3	295.6	5.4	384.9	7.5
2007	264.9	4.3	311.6	5.4	413.8	7.5
2008	276.0	4.2	328.1	5.3	444.9	7.5

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	4.5%	5.2%	6.5%
1988-2008	4.5%	5.4%	7.0%

AVERAGE HOURLY EARNINGS (U.S.)
NON-AGRICULTURAL BUSINESS SECTOR
(1977=100)



AVERAGE HOURLY EARNINGS (U.S.)
NON-AGRICULTURAL BUSINESS SECTOR
HISTORY AND FORECAST
(1977 = 100)

Year	Actual	Annual % Change
1978	108.6	8.6
1979	118.9	9.5
1980	131.1	10.3
1981	143.6	9.5
1982	154.8	7.8
1983	161.5	4.3
1984	167.8	3.9
1985	174.9	4.2
1986	182.4	4.3
1987	189.3	3.8
1988	198.2	4.7

Compound Average Annual Growth Rate
1978 through 1988 6.2%

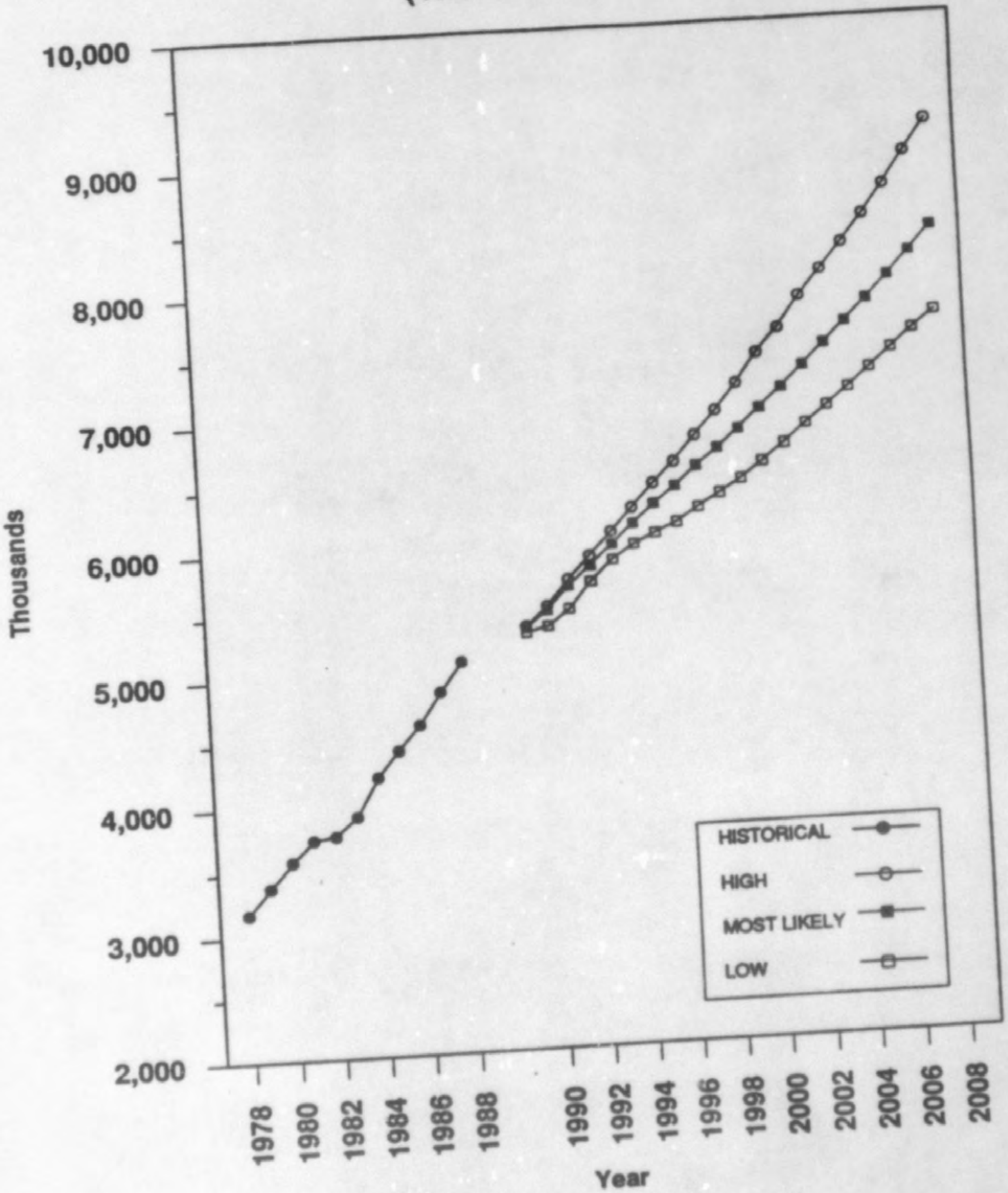
YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	207.5	4.7	208.6	5.3	209.3	5.6
1990	216.5	4.4	219.5	5.2	221.1	5.7
1991	227.1	4.9	230.9	5.2	232.8	5.3
1992	238.1	4.9	243.0	5.3	246.9	6.1
1993	249.0	4.6	255.6	5.2	263.4	6.7
1994	260.2	4.5	269.1	5.3	281.8	7.0
1995	272.1	4.6	284.1	5.6	302.3	7.3
1996	284.9	4.7	300.3	5.7	325.0	7.5
1997	298.5	4.8	317.4	5.7	350.0	7.7
1998	312.8	4.8	335.8	5.8	377.4	7.8
1999	328.2	4.9	356.0	6.0	407.3	7.9
2000	344.3	4.9	377.4	6.0	439.9	8.0
2001	361.2	4.9	400.1	6.0	474.7	7.9
2002	378.9	4.9	423.8	5.9	511.8	7.8
2003	397.1	4.8	448.3	5.8	551.3	7.7
2004	415.7	4.7	473.9	5.7	593.7	7.7
2005	434.8	4.6	500.9	5.7	639.5	7.7
2006	454.3	4.5	528.9	5.6	688.7	7.7
2007	474.7	4.5	558.4	5.6	741.7	7.7
2008	495.5	4.4	589.1	5.5	798.7	7.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	4.7%	5.4%	6.7%
1988-2008	4.7%	5.6%	7.2%

FLORIDA NON-AGRICULTURAL EMPLOYMENT

(Thousands)



FLORIDA NON-AGRICULTURAL EMPLOYMENT HISTORY AND FORECAST
(Thousands)

Year	Actual	Annual % Change
1978	3,180.6	8.4
1979	3,381.2	6.3
1980	3,576.2	5.8
1981	3,736.9	4.5
1982	3,761.9	0.7
1983	3,905.6	3.8
1984	4,208.7	7.8
1985	4,410.0	4.8
1986	4,599.4	4.3
1987	4,852.5	5.5
1988	5,080.2	4.7

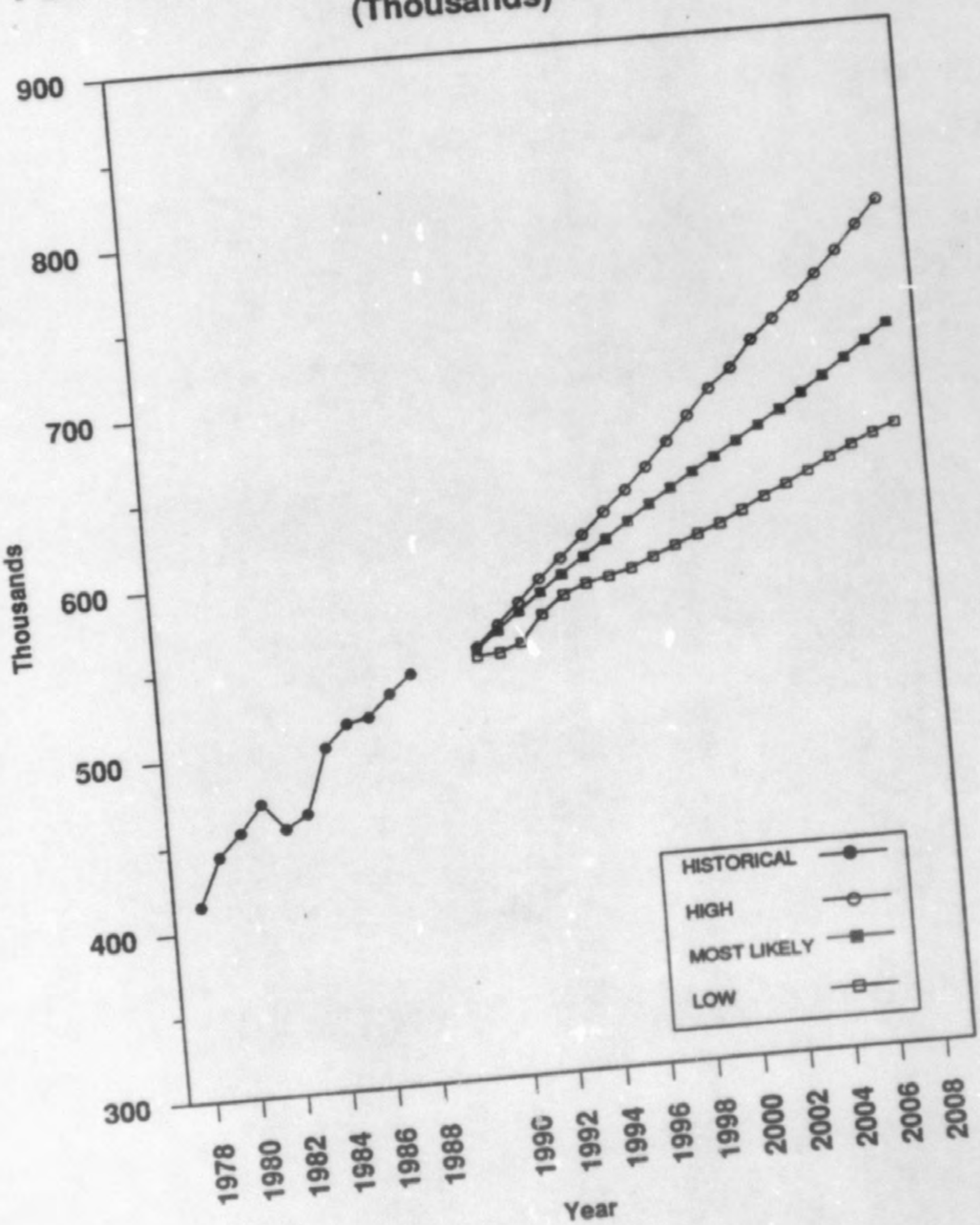
Compound Average Annual Growth Rate
1978 through 1988 4.8%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	5,283.5	4.0	5,320.0	4.7	5,335.8	5.0
1990	5,329.4	0.9	5,458.3	2.6	5,487.6	2.8
1991	5,460.9	2.5	5,643.9	3.4	5,694.3	3.8
1992	5,667.9	3.8	5,796.3	2.7	5,873.6	3.1
1993	5,835.5	3.0	5,958.6	2.8	6,056.5	3.1
1994	5,948.8	1.9	6,113.5	2.6	6,241.8	3.1
1995	6,031.5	1.4	6,260.2	2.4	6,419.0	2.8
1996	6,107.8	1.3	6,390.1	2.1	6,576.1	2.4
1997	6,219.2	1.8	6,535.9	2.3	6,765.8	2.9
1998	6,317.6	1.6	6,664.1	2.0	6,953.4	2.8
1999	6,422.5	1.7	6,803.9	2.1	7,158.7	3.0
2000	6,542.8	1.9	6,958.1	2.3	7,388.5	3.2
2001	6,673.7	2.0	7,113.3	2.2	7,576.3	2.5
2002	6,817.0	2.1	7,277.4	2.3	7,821.7	3.2
2003	6,953.2	2.0	7,440.3	2.2	8,027.8	2.6
2004	7,091.2	2.0	7,604.5	2.2	8,232.7	2.6
2005	7,236.1	2.0	7,777.1	2.3	8,446.8	2.6
2006	7,380.0	2.0	7,957.1	2.3	8,674.9	2.7
2007	7,520.1	1.9	8,142.8	2.3	8,922.3	2.9
2008	7,654.1	1.8	8,330.5	2.3	9,166.8	2.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.2%	2.8%	3.2%
1988-2008	2.1%	2.5%	3.0%

FLORIDA MANUFACTURING EMPLOYMENT
(Thousands)



FLORIDA MANUFACTURING EMPLOYMENT
HISTORY AND FORECAST
(Thousands)

Year	Actual	Annual % Change
1978	415.5	9.1
1979	443.6	6.8
1980	456.4	2.9
1981	472.2	3.5
1982	456.7	-3.3
1983	464.3	1.7
1984	501.8	8.1
1985	514.4	2.5
1986	517.2	0.5
1987	529.9	2.5
1988	540.8	2.1

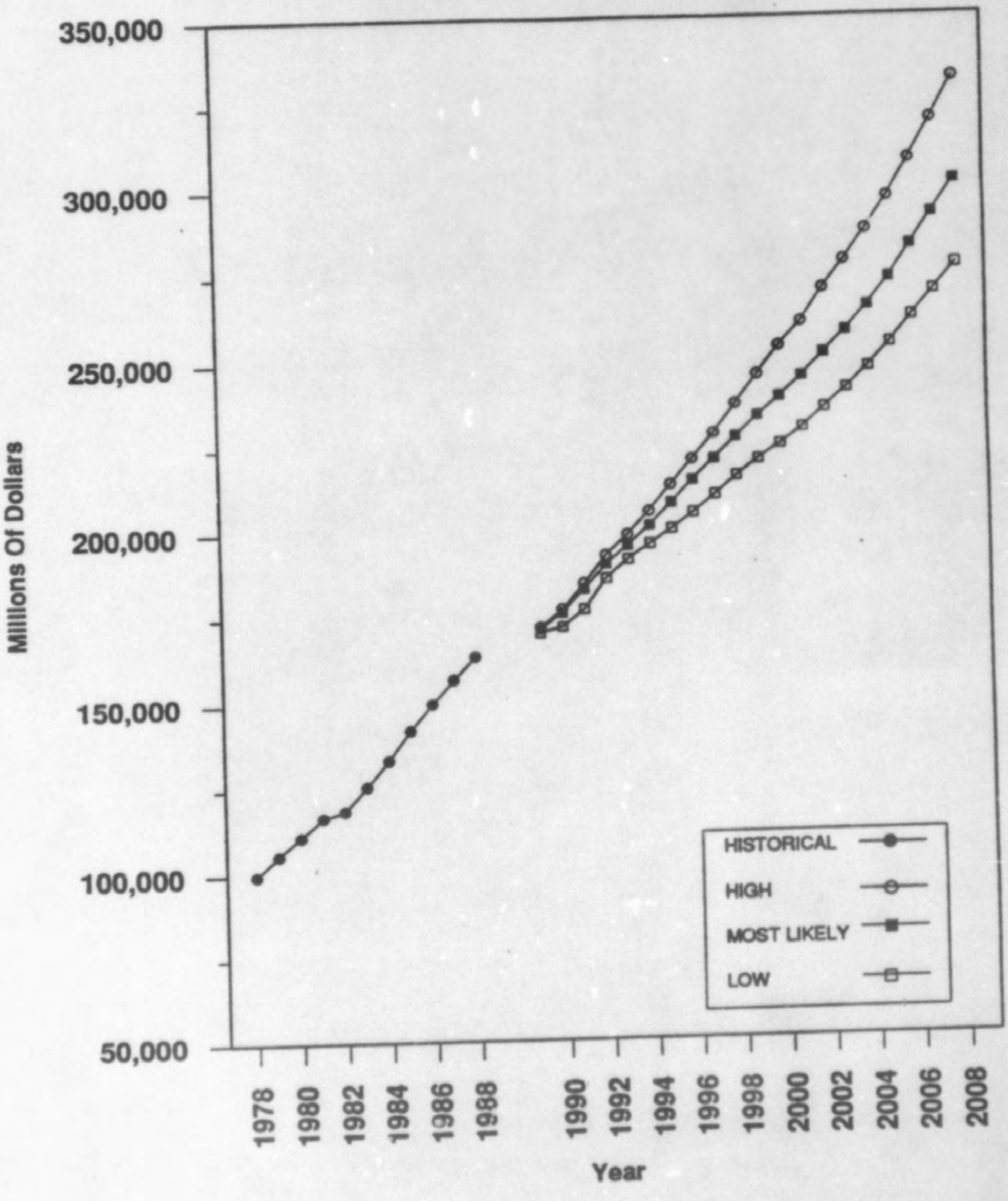
Compound Average Annual Growth Rate
1978 through 1988 2.7%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	547.7	1.3	551.5	2.0	553.1	2.3
1990	548.6	0.2	561.9	1.9	564.9	2.1
1991	553.5	0.9	572.1	1.8	577.2	2.2
1992	569.1	2.8	582.0	1.7	589.8	2.2
1993	579.4	1.8	591.7	1.7	601.4	2.0
1994	584.9	0.9	601.1	1.6	613.7	2.1
1995	588.0	0.5	610.3	1.5	625.8	2.0
1996	591.9	0.7	619.3	1.5	637.3	1.8
1997	597.5	1.0	628.0	1.4	650.0	2.0
1998	603.3	1.0	636.4	1.3	664.0	2.2
1999	608.5	0.9	644.6	1.3	678.2	2.1
2000	613.6	0.8	652.6	1.2	693.0	2.2
2001	620.1	1.0	660.9	1.3	703.9	1.6
2002	626.9	1.1	669.2	1.3	719.3	2.2
2003	633.1	1.0	677.4	1.2	730.9	1.6
2004	639.8	1.1	686.1	1.3	742.8	1.6
2005	646.7	1.1	695.0	1.3	754.9	1.6
2006	653.2	1.0	704.3	1.3	767.8	1.7
2007	659.0	0.9	713.5	1.3	781.8	1.8
2008	664.2	0.8	722.9	1.3	795.4	1.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.1%	1.6%	2.1%
1988-2008	1.0%	1.5%	1.9%

FLORIDA REAL PERSONAL INCOME
(Millions of 1982 Dollars)



FLORIDA REAL PERSONAL INCOME
HISTORY AND FORECAST
(Millions of 1982 Dollars)

Year	Actual	Annual % Change
1978	99,715	8.3
1979	105,583	5.9
1980	110,945	5.1
1981	116,592	5.1
1982	118,530	1.7
1983	125,496	5.9
1984	133,142	6.1
1985	141,860	6.5
1986	149,601	5.5
1987	156,791	4.8
1988	163,284	4.1

Compound Average Annual Growth Rate
1978 through 1988 5.1%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	169,891	4.0	171,064	4.8	171,573	5.1
1990	171,682	1.1	175,835	2.8	176,778	3.0
1991	176,724	2.9	182,647	3.9	184,279	4.2
1992	185,672	5.1	189,878	4.0	192,412	4.4
1993	191,188	3.0	195,222	2.8	198,429	3.1
1994	195,634	2.3	201,050	3.0	205,268	3.4
1995	200,017	2.2	207,601	3.3	212,866	3.7
1996	204,604	2.3	214,060	3.1	220,290	3.5
1997	209,698	2.5	220,376	3.0	228,127	3.6
1998	215,056	2.6	226,851	2.9	236,700	3.8
1999	220,064	2.3	233,133	2.8	245,290	3.6
2000	224,462	2.0	238,707	2.4	253,474	3.3
2001	229,495	2.2	244,610	2.5	260,531	2.8
2002	235,336	2.5	251,232	2.7	270,020	3.6
2003	240,891	2.4	257,767	2.6	278,119	3.0
2004	246,972	2.5	264,849	2.7	286,729	3.1
2005	253,935	2.8	272,921	3.0	296,423	3.4
2006	261,667	3.0	282,130	3.4	307,582	3.8
2007	269,042	2.8	291,318	3.3	319,205	3.8
2008	276,497	2.8	300,932	3.3	331,139	3.7

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.8%	3.3%	3.8%
1988-2008	2.7%	3.1%	3.6%

REAL AVERAGE PRICE OF ELECTRICITY FOR TOTAL CUSTOMERS
HISTORY AND FORECAST
(1982-1984 Dollars)

Year	Cents/kWh	Annual % Change
1978	6.17	
1979	6.24	2.1
1980	6.29	0.4
1981	7.16	14.1
1982	6.72	-7.2
1983	6.64	-1.0
1984	7.63	15.6
1985	7.67	0.3
1986	6.84	-11.4
1987	6.55	-3.5
1988	6.48	-1.3

Compound Average Annual Growth Rate
1978 through 1988 0.5%

Year	Most Likely Cents/kWh*	Annual % Change
1989	5.90	-8.5
1990	5.64	-4.8
1991	5.64	-0.0
1992	5.78	2.4
1993	5.79	0.2
1994	5.96	2.8
1995	5.94	-0.3
1996	5.90	-0.7
1997	6.01	1.9
1998	6.03	0.3
1999	5.96	-1.2
2000	5.95	-0.2
2001	5.91	-0.6
2002	5.89	-0.3
2003	5.98	1.5
2004	5.98	0.1
2005	5.84	-2.4
2006	5.85	0.3
2007	5.78	-1.2
2008	5.73	-1.0

Compound Average Annual Growth Rate

1988 through 1998 -0.7%
1988 through 2008 -0.6%

* Also used for high and low scenarios

SHORT-TERM FORECAST ASSUMPTIONS

HISTORY AND FORECAST OF :

- Real Average Price Of Electricity
- Consumer Price Index
- Florida Non-Agricultural Employment
- Cooling And Heating Degree Days - Weighted By Divisional Sales Across Miami, Ft. Myers, And Daytona

REAL AVERAGE PRICE OF ELECTRICITY
HISTORY AND FORECAST
(Cents/kWh 1982-84 Dollars)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average For the Year
1972	4.72	4.79	4.71	4.82	4.62	4.56	4.56	4.57	4.68	4.70	4.79	4.82	4.70
1973	4.81	4.94	4.87	4.79	4.99	4.91	4.88	4.77	4.89	4.93	5.10	5.13	4.92
1974	5.21	5.38	5.65	5.75	5.80	5.71	5.75	5.98	5.83	6.16	6.21	6.22	5.81
1975	6.10	6.36	5.88	5.88	6.15	6.64	6.85	6.87	6.39	6.48	6.33	6.34	6.36
1976	5.72	6.18	5.96	5.78	5.73	5.77	6.02	5.99	5.90	6.13	6.40	5.22	5.90
1977	6.39	6.23	6.35	5.85	5.85	5.96	6.26	6.83	6.97	6.74	6.58	6.28	6.36
1978	6.14	6.31	6.36	6.49	5.92	5.95	6.27	6.15	6.11	6.24	6.20	5.89	6.17
1979	5.68	5.80	6.03	6.05	5.89	6.60	6.55	6.75	6.38	6.44	6.47	6.26	6.24
1980	5.66	6.16	6.33	6.64	6.64	6.51	6.53	6.48	6.43	6.07	5.99	6.11	6.29
1981	6.08	6.08	6.63	6.64	7.64	7.76	7.73	7.67	7.62	7.40	7.34	7.38	7.16
1982	7.34	7.32	7.35	6.75	6.58	6.43	6.42	6.50	6.47	6.45	6.50	6.51	6.72
1983	6.62	6.66	6.59	6.63	6.56	6.53	6.55	6.50	6.38	6.79	6.91	7.01	6.64
1984	7.17	7.14	7.11	7.63	7.71	7.94	8.09	8.14	8.10	7.53	7.45	7.55	7.63
1985	7.64	7.90	7.58	7.80	7.79	7.79	7.77	7.73	7.71	7.47	7.42	7.43	7.67
1986	7.51	7.58	6.88	7.15	7.04	6.58	6.54	6.51	6.49	6.62	6.61	6.57	6.84
1987	6.61	6.51	6.59	6.24	6.11	6.48	6.55	6.50	6.47	6.80	6.84	6.87	6.55
1988	6.89	6.94	6.88	5.65	6.71	6.64	6.63	6.62	6.55	6.11	6.06	6.07	6.48
1989	6.09	5.97	6.06	5.89	5.18	6.17	6.20	6.18	6.14	5.64	5.65	5.65	5.90
1990	5.65	5.72	5.66	5.83	5.77	5.70	5.65	5.61	5.58	5.49	5.52	5.54	5.64
1991	5.71	5.72	5.66	5.86	5.79	5.72	5.67	5.63	5.60	5.43	5.46	5.48	5.64

CONSUMER PRICE INDEX
HISTORY AND FORECAST
(1982-84 = 100)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average For the Year
1972	41.1	41.3	41.4	41.5	41.6	41.7	41.9	42.0	42.1	42.3	42.4	42.5	41.8
1973	42.6	42.9	43.3	43.6	43.9	44.2	44.3	45.1	45.2	45.6	45.9	46.2	44.4
1974	46.6	47.2	47.8	48.0	48.6	49.0	49.4	50.0	50.6	51.1	51.5	51.9	49.3
1975	52.1	52.5	52.7	52.9	53.2	53.6	54.2	54.3	54.6	54.9	55.3	55.5	53.8
1976	55.6	55.8	55.9	56.1	56.5	56.8	57.1	57.4	57.6	57.9	58.0	58.2	56.9
1977	58.5	59.1	59.5	60.0	60.3	60.7	61.0	51.2	61.4	61.6	61.9	62.1	60.6
1978	62.5	62.9	63.4	63.9	64.5	65.2	65.7	66.0	66.5	67.1	67.4	67.7	65.2
1979	68.3	69.1	69.8	70.6	71.5	72.3	73.1	73.8	74.6	75.2	75.9	76.7	72.6
1980	77.8	78.9	80.1	81.0	81.8	82.7	82.7	83.3	84.0	84.8	85.5	86.3	82.4
1981	87.0	87.9	88.5	89.1	89.8	90.6	91.6	92.3	93.2	93.4	93.7	94.0	90.9
1982	94.3	94.6	94.5	94.9	95.8	97.0	97.5	97.7	97.9	98.2	98.0	97.6	96.5
1983	97.8	97.9	97.9	98.6	99.2	99.5	99.9	100.2	100.7	101.0	101.2	101.3	99.6
1984	101.9	102.4	102.6	103.1	103.4	103.7	104.1	104.5	105.0	105.3	105.3	105.3	103.9
1985	105.5	106.0	106.4	106.9	107.3	107.6	107.8	108.0	108.3	108.7	109.0	109.3	107.6
1986	109.6	109.3	108.8	108.6	108.9	109.5	109.5	109.7	110.2	110.3	110.4	110.5	109.6
1987	111.2	111.6	112.1	112.7	113.1	113.5	113.8	114.4	115.0	115.3	115.4	115.4	113.6
1988	115.7	116.0	116.5	117.1	117.5	118.0	118.5	119.0	119.8	120.2	120.3	120.5	118.3
1989	121.1	121.6	122.3	123.1	123.3	123.9	124.4	125.1	125.9	126.3	126.5	126.7	124.1
1990	127.2	127.6	128.2	128.9	129.4	130.0	130.5	131.1	132.0	132.4	132.6	132.8	130.2
1991	133.4	133.8	134.4	135.2	135.7	136.3	136.9	137.6	138.5	138.9	139.1	139.3	136.6
1992	140.0	140.5	141.1	141.9	142.5	143.1	143.8	144.5	145.4	145.9	146.1	146.4	143.4

FLORIDA NON-AGRICULTURAL EMPLOYMENT
HISTORY AND FORECAST
(Thousands)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average For the Year
1972	2371.2	2398.0	2438.1	2450.2	5455.4	2465.6	2408.0	2427.8	2488.1	2541.0	2594.2	2658.3	2474.7
1973	2647.0	2683.4	2726.8	2732.6	2739.6	2760.8	2724.4	2747.7	2775.0	2802.6	2852.0	2886.4	2756.5
1974	2859.1	2874.7	2893.2	2905.9	2906.5	2905.3	2847.2	2838.6	2854.4	2844.9	2848.6	2857.6	2869.7
1975	2803.3	2794.2	2798.2	2782.6	2769.7	2755.4	2680.3	2680.6	2699.0	2701.6	2725.2	2766.1	2746.4
1976	2765.5	2782.7	2802.9	2798.0	2784.2	2775.8	2738.9	2741.6	2766.3	2777.6	2811.9	2860.4	2784.3
1977	2844.7	2875.0	2912.1	2921.8	2912.6	2917.1	2901.1	2912.9	2944.9	2966.8	3018.1	3073.8	2933.4
1978	3077.5	3125.2	3173.5	3163.0	3162.4	3190.0	3134.2	3152.6	3181.9	3218.1	3265.9	3321.9	3180.5
1979	3307.1	3327.1	3375.9	3375.7	3369.0	3385.7	3316.6	3335.5	3376.0	3421.4	3470.2	3514.4	3381.2
1980	3515.7	3563.1	3590.0	3574.9	3567.3	3565.7	3513.4	3524.1	3260.9	3604.6	3639.5	3695.6	3576.2
1981	3678.0	3719.7	3757.3	3762.1	3755.3	3760.2	3688.8	3675.1	3726.9	3747.5	3765.8	3805.7	3736.9
1982	3771.9	3778.9	3816.4	3796.1	3769.6	3754.1	3693.9	3679.4	3707.3	3740.0	3793.7	3762.0	3756.1
1983	3788.6	3816.1	3856.2	3882.3	3883.7	3895.1	3855.9	3852.3	3939.3	3978.5	4029.2	4090.1	3905.6
1984	4094.1	4127.8	4187.8	4179.6	4191.6	4201.1	4156.2	4162.5	4227.3	4273.3	4328.8	4368.5	4208.2
1985	4344.3	4394.7	4418.2	4424.5	4419.6	4417.2	4377.8	4380.3	4411.3	4477.7	4539.7	4559.6	4430.4
1986	4519.3	4539.2	4569.6	4565.1	4561.3	4550.7	4504.0	4508.2	4578.1	4620.8	4667.0	4737.9	4576.8
1987	4722.0	4754.8	4800.2	4797.4	4787.1	4741.3	4722.5	4794.9	4838.9	4897.6	4952.9	4737.9	4795.6
1988	4954.3	5013.5	5065.4	5058.1	5061.2	5059.1	5022.6	5014.5	5083.6	5136.1	5236.5	5257.1	5080.2
1989	5191.2	5245.3	5302.1	5299.6	5301.5	5301.8	5255.5	5255.0	5327.7	5385.5	5468.8	5506.1	5320.0
1990	5325.5	5383.1	5439.6	5436.3	5439.7	5439.9	5393.3	5390.1	5465.5	5523.3	5614.3	5649.1	5458.3
1991	5505.8	5565.0	5624.4	5621.2	5624.3	5624.5	5576.3	5574.0	5651.7	5712.2	5805.2	5842.2	5643.9
1992	5654.1	5715.1	5775.9	5772.7	5776.1	5776.4	5727.1	5724.5	5804.5	5866.5	5962.4	6000.2	5796.3

NOTE: Historical numbers represent preliminary estimates.

COOLING DEGREE DAYS
WEIGHTED BY DIVISIONAL SALES ACROSS MIAMI, FORT MYERS, AND DAYTONA BEACH

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1965	1	8	57	96	156	222	227	258	201	128	28	2	1,390
1966	3	4	5	24	125	154	253	267	225	140	11	0	1,217
1967	14	2	23	62	178	184	278	252	219	92	9	15	1,335
1968	0	0	6	84	143	189	283	318	253	169	28	11	1,487
1969	0	0	8	86	182	271	332	304	258	214	19	2	1,681
1970	0	1	39	150	169	260	313	343	288	204	25	10	1,807
1971	16	35	32	85	180	219	301	274	225	185	56	36	1,648
1972	26	3	21	76	133	224	271	275	238	150	72	46	1,541
1973	24	5	69	81	196	247	272	266	269	159	98	14	1,704
1974	36	20	74	100	211	249	277	323	319	140	45	8	1,805
1975	26	36	70	131	201	251	262	306	259	187	77	7	1,818
1976	2	8	65	66	159	191	310	275	218	104	36	17	1,456
1977	0	3	76	71	134	269	325	312	294	126	74	32	1,723
1978	3	0	7	49	205	281	309	307	273	167	87	48	1,741
1979	3	4	2	120	224	268	336	282	252	150	93	12	1,751
1980	3	6	70	70	175	260	312	306	281	200	78	0	1,767
1981	0	7	9	115	194	325	367	320	246	197	36	24	1,845
1982	14	37	71	128	138	285	341	321	254	144	58	49	1,846
1983	4	0	5	32	148	245	342	295	230	151	24	28	1,510
1984	6	5	23	56	127	211	273	291	212	156	33	20	1,417
1985	4	10	19	60	189	287	251	304	238	228	111	5	1,711
1986	0	6	27	21	149	232	295	317	296	210	150	40	1,746
1987	9	10	24	33	177	309	336	360	282	112	82	18	1,757
1988	5	8	25	93	139	267	138	313	315	140	99	7	1,554
Normals*	8	9	35	79	168	246	292	299	256	161	60	19	1,636

*NORMAL COOLING DEGREE DAYS BASED ON 24 YEAR NORMAL CDD'S

NOTE: DUE TO ROUNDING, TOTAL COOLING DEGREE DAYS MAY NOT EQUAL SUM OF MONTHS

HEATING DEGREE DAYS
WEIGHTED BY DIVISIONAL SALES ACROSS MIAMI, FORT MYERS, AND DAYTONA BEACH

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1965	96	39	44	0	0	0	0	0	0	0	4	48	233
1966	132	73	33	2	0	0	0	0	0	0	48	97	388
1967	52	69	2	0	0	0	0	0	0	0	4	46	176
1968	95	168	84	0	0	0	0	0	0	3	61	136	549
1969	63	117	93	0	0	0	0	0	0	0	41	111	428
1970	178	116	30	0	0	0	0	0	0	0	66	37	430
1971	101	70	49	9	0	0	0	0	0	0	2	0	234
1972	9	60	2	0	0	0	0	0	0	0	17	59	151
1973	70	124	4	2	0	0	0	0	0	1	3	124	330
1974	0	64	1	0	0	0	0	0	0	0	6	71	145
1975	22	8	18	0	0	0	0	0	0	0	47	82	179
1976	145	54	1	0	0	0	0	0	0	0	36	81	320
1977	243	110	9	0	0	0	0	0	0	2	17	95	478
1978	185	167	57	0	0	0	0	0	0	0	0	10	420
1979	119	126	23	0	0	0	0	0	0	0	11	43	324
1980	87	160	41	0	0	0	0	0	0	0	30	93	414
1981	274	49	25	0	0	0	0	0	0	0	19	124	495
1982	103	6	11	0	0	0	0	0	0	1	4	50	178
1983	121	68	67	9	0	0	0	0	0	0	13	94	374
1984	126	73	42	3	0	0	0	0	0	0	17	40	304
1985	208	88	8	7	0	0	0	0	0	0	6	129	449
1986	124	39	83	0	0	0	0	0	0	0	0	4	252
1987	125	40	21	43	0	0	0	0	0	0	11	54	297
1988	97	97	45	0	0	0	0	0	0	0	0	59	300
Normals*	116	83	33	3	0	0	0	0	0	0	19	70	327

* NORMAL HEATING DEGREE DAYS BASED ON 24 YEAR NORMAL HDD'S

NOTE: DUE TO ROUNDING, TOTAL HEATING DEGREE DAYS MAY NOT EQUAL TO SUM OF MONTHS

APPENDICES

- Annual Load Factors Based On Annual And Summer Peaks (Historical And Forecast)
- System Loss Estimates (Historical And Forecast)
- Weather Normalized Jurisdictional Summer And Winter Peak Loads
- Weather Normalized Jurisdictional Net Energy For Load

HISTORY OF ANNUAL LOAD FACTOR
BASED ON ANNUAL PEAK
(Actual Load Served)

Year	Percent
1978	57.9
1979	58.9
1980	56.7
1981	53.1
1982	52.8
1983	56.1
1984	58.9
1985	51.0
1986	54.8
1987	56.8
1988	59.1

FORECAST OF ANNUAL LOAD FACTOR
BASED ON ANNUAL PEAK

Year	Percent*
1989	60.4
1990	60.2
1991	60.0
1992	59.6
1993	59.2
1994	58.4
1995	57.7
1996	57.0
1997	56.7
1998	56.4
1999	56.2
2000	55.7
2001	55.8
2002	55.7
2003	55.6
2004	55.4
2005	55.6
2006	55.6
2007	55.7
2008	56.0

* Based on Most-Likely Scenario

NOTE: $\text{Load Factor} = \dfrac{\text{Net Energy for Company Load}}{\text{Hours per Year x Annual Peak Load}}$

HISTORY OF ANNUAL LOAD FACTOR
BASED ON SUMMER PEAK
(Actual Load Served)

Year	Percent*
1978	59.8
1979	59.8
1980	57.3
1981	58.6
1982	58.3
1983	56.1
1984	58.9
1985	60.0
1986	60.3
1987	56.8
1988	59.1

FORECAST OF ANNUAL LOAD FACTOR
BASED ON SUMMER PEAK

Year	Percent
1989	60.0
1990	61.0
1991	61.5
1992	61.8
1993	61.8
1994	61.7
1995	61.5
1996	61.3
1997	61.5
1998	61.5
1999	61.4
2000	61.3
2001	61.7
2002	61.9
2003	62.2
2004	62.2
2005	62.5
2006	62.8
2007	63.4
2008	63.8

* Based on Most-Likely Scenario

NOTE: $\text{Load Factor} = \dfrac{\text{Net Energy for Company Load}}{\text{Hours per Year} \times \text{Annual Peak Load}}$

HISTORY OF SYSTEM LOSS ESTIMATES
(INCLUDING COMPANY USE)

YEAR	LOSS FACTOR PERCENT
1980	7.72
1981	7.51
1982	6.85
1983	7.45
1984	7.17
1985	8.15
1986	6.94
1987	8.15
1988	6.82

FORECAST OF SYSTEM LOSS ESTIMATES

YEAR	LOSS FACTOR PERCENT
1989	7.21
1990	7.18
1991	7.17
1992	7.16
1993	7.06
1994	6.99
1995	6.98
1996	6.98
1997	6.97
1998	6.97
1999	6.96
2000	6.96
2001	6.96
2002	6.95
2003	6.95
2004	6.95
2005	6.94
2006	6.94
2007	6.94
2008	6.93

ACTUAL VS WEATHER NORMALIZED JURISDICTIONAL SUMMER PEAK LOAD

(in mW)

Year	Actual Peaks	Normalized Peaks	Difference	% Difference is of Actual
1967	3,090	3,359	269	8.7
1968	3,689	3,601	-88	-2.4
1969	4,195	4,216	21	0.5
1970	4,842	4,963	121	2.5
1971	5,203	5,596	393	7.6
1972	6,019	6,250	231	3.8
1973	6,629	7,079	450	6.8
1974	6,965	6,989	24	0.3
1975	6,782	6,993	211	3.1
1976	7,246	7,008	-238	-3.3
1977	7,446	7,282	-164	-2.2
1978	7,889	8,100	211	2.7
1979	8,169	8,158	-11	-0.1
1980	9,006	8,383	-623	-6.9
1981	9,096	8,153	-943	-10.4
1982	9,185	9,036	-149	-1.6
1983	9,958	8,958	-1,000	-10.0
1984	9,763	9,518	-245	-2.5
1985	10,346	9,870	-476	-4.6
1986	10,862	11,267	405	3.7
1987	12,227	11,518	-709	-5.8
1988	12,173	12,112	-61	-0.5

ACTUAL VS WEATHER NORMALIZED
JURISDICTIONAL WINTER PEAK LOAD
(in mW)

Year	Actual Peaks	Normalized Peaks	Difference	% Difference is of Actual
1967	2,607	2,926	319	12.2
1968	3,223	3,430	207	6.4
1969	3,642	3,536	-106	-2.9
1970	4,565	4,306	-259	-5.7
1971	4,885	4,681	-204	-4.2
1972	4,495	4,828	333	7.4
1973	5,570	5,630	60	1.1
1974	5,958	6,219	261	4.4
1975	5,554	6,007	453	8.2
1976	6,896	6,837	-59	-0.9
1977	8,144	7,576	-568	-7.0
1978	8,117	7,958	-159	-2.0
1979	8,230	8,581	351	4.3
1980	9,179	9,401	222	2.4
1981	9,963	8,816	-1,147	-11.5
1982	10,139	9,344	-795	-7.8
1983	8,590	9,719	1,129	13.1
1984	9,699	7,870	-1,829	-18.9
1985	12,175	10,099	-2,076	-17.1
1986	11,798	11,495	-303	-2.6
1987	10,574	11,476	902	8.5
1988	12,221	12,028	-193	-1.6

ACTUAL VS WEATHER NORMALIZED
JURISDICTIONAL NET ENERGY FOR LOAD
(in gWh)

Year	Actual Net Energy	Normalized Net Energy	Difference	% Difference is of Actual
1967	16,292	16,504	212	1.3
1968	18,878	18,986	108	0.6
1969	21,640	21,675	35	0.2
1970	24,445	24,232	-213	-0.9
1971	27,083	27,006	-77	-0.[illegible]
1972	30,404	30,537	133	0.4
1973	33,862	33,539	-323	-1.0
1974	33,827	33,633	-194	-0.6
1975	35,392	35,228	-164	-0.5
1976	36,054	36,605	551	1.5
1977	38,672	38,110	-562	-1.5
1978	41,226	40,652	-574	-1.4
1979	42,650	42,463	-187	-0.4
1980	45,204	44,527	-677	-1.5
1981	46,502	45,067	-1,435	-3.1
1982	46,962	46,481	-481	-1.0
1983	49,045	49,364	319	0.7
1984	50,424	51,295	871	1.7
1985	54,961	53,294	-1,667	-3.0
1986	57,181	57,444	263	0.5
1987	60,251	61,681	1430	2.4
988	63,774	63,713	-61	-0.1

Appendix D
Fuel Price Forecast Methodology And Results

Fuel Price Forecast Methodology And Results

Introduction

The forecasting of fuel prices and natural gas availability and the resulting price differentials between alternative fuels is one of the factors in determining the type of unit for the next capacity addition. In this light, FPL follows a methodology for the development of several reasonable and understandable fuel price scenarios to minimize the uncertainty and resulting risk of unanticipated changes in the various fuel markets. FPL develops fuel price and availability forecasts for various scenarios that represent future potential market conditions. The following narrative describes the methodology and the underlying world energy assumptions employed by FPL in developing the scenarios and long-term projections for residual and distillate fuel oil prices, natural gas prices and availability and coal prices, which were used in this study.

Methodology

FPL develops long-term fuel price forecasts for residual and distillate fuel oil, natural gas and coal on an annual basis or when major events in the energy market environment warrant a revision. In general, FPL reviews current and projected domestic and foreign events which could affect the worldwide supply and demand for crude oil, and the domestic supply and demand for residual fuel oil, natural gas, mine mouth coal and coal transportation. FPL personnel with expertise and direct experience in petroleum exploration, production refining economics, and petroleum and coal markets analyze these market events, review all data available through industry publications and public information, hold discussions with industry consultants on retainer and attend and participate in international energy conferences to acquire an in-depth understanding of current and future fuel markets, fuel availability and inter-fuel economics.

FPL then develops a most likely or base case and alternate scenarios for the supply, demand and resulting price for crude oil, mine mouth coal and coal transportation that is consistent with this understanding of the current and future fuel markets. The scenario approach used describes international and domestic events which may or may not happen which can affect the supply, demand and/or price of fuels over time. Scenarios are not predictions of specific events, but a description of potential market conditions which could result in different fuel prices and/or availability. The base case scenario describes market conditions which are considered the most likely to occur and result in the most likely forecast of fuel prices and availability. The alternate scenarios are considered less likely to occur and describe market conditions which result in higher or lower prices and different availability than the base case. These scenarios are useful, believable, understandable and reflect a logical understanding of the macro and microeconomics of energy, world energy politics and operations of the energy industry. An annual projection of real (constant 1989 dollar) prices for crude oil, mine mouth coal and coal transportation is developed for each scenario. These year to year real price changes reflect projected changes in supply and demand balances for the commodity, technologies or industry operation, not inflationary changes.

The next step in projecting fuel oil and natural gas prices is to develop market price relationships between crude oil and residual and distillate fuel oil available at the U.S. Gulf Coast, and between residual fuel oil and natural gas at the U.S. Gulf Coast, based on anticipated product supply and demand balances, and refining and exploration and development economics. FPL then develops market prices for residual and distillate fuel oil in real dollars at the U.S. Gulf Coast by multiplying these price relationships by the previously projected real crude oil prices. Marine transportation costs for residual and distillate fuel oil in real dollars from the U.S. Gulf Coast to Florida, as well as average variable costs, such as dockage, wharfage and other port charges associated with moving these fuels, are then added to arrive at a delivered price for residual and distillate fuel oil in real dollars. Market prices for natural gas, in real dollars, are developed in a similar fashion based on residual fuel oil prices. Pipeline transportation rates on the Florida Gas Transmission System in real dollars are then added to the wellhead or U.S. Gulf Coast price of natural gas to arrive at a delivered price for market natural gas in real dollars.

As real prices of fuel oil and natural gas rise, the potential for the development of alternate fuel technologies and alternative fuels increases. In order to reflect OPEC's objective of minimizing this development, FPL assumed a diminishing rate of increase in the real price of crude oil in the latter part of the planning horizon as the real price of oil approached the estimated cost of alternative energy sources.

Coal price scenarios were developed based upon the reaction of the domestic coal industry to changes in oil and natural gas market conditions. Based on the assumption that supply of coal will be abundant and relatively unchanged under all crude oil scenarios, the differences between coal price scenarios and resulting mine mouth coal prices reflected different levels in coal demand, as oil and natural gas became more or less costly.

A projection of coal transportation costs in real dollars from the mines of West Virginia to the Martin Plant site was developed independent of the mine mouth coal price forecast. Coal transportation costs assumed that the plant would be built with access to competitive modes of delivery.

In order to develop delivered fuel price forecasts in nominal dollars (dollars of the year), the real price was multiplied by FPL's forecast of the GNP implicit price deflator developed for the particular scenario. Delivered fuel prices in nominal dollars were the values used in the studies.

Finally, a review of all fuel forecasts is performed to ensure reasonableness and consistency by: 1) comparing relative fuel costs on a dollars per million BTU basis, 2) reviewing individual product and crude oil supply and demand balances and 3) analyzing petroleum and coal industry capability to meet product requirements consistent with the forecasts.

The scenarios developed and the corresponding fuel price and natural gas availability forecasts assume no change will occur in existing domestic laws and regulations which would affect the delivered cost of fuels to Florida. Therefore, we did not contemplate items such as strong acid rain legislation, changes to the Staggers Rail Act, product or crude oil import fees, etc. In addition, it was assumed that there would be no significant additions to the existing fuel transportation network in the state. New ports and receiving terminals were assumed to be included in the capital estimates for the new generation facility and the costs are not reflected as fuel costs.

Fuel Oils

Any projection of residual and distillate fuel oil prices must consider two major market factors: the crude oil market environment and the effect of refinery operations on product availability.

Crude Oil

The crude oil market is influenced by free world demand, non-OPEC supply and the actions of OPEC producers. The demand for OPEC oil is the difference between free world demand and non-OPEC supply. OPEC is effectively the marginal producer since non-OPEC countries have historically produced at virtually full capacity.

The ability of OPEC and, in particular, Saudi Arabia, to bridge the gap between satisfying the political and economic needs of all of its member nations and still obtain a "fair market share" by means of a supply agreement among producers will, in large part, determine the future price of crude oil. This, in turn, will have a direct impact on the future prices for residual and distillate fuel oil. The scenarios developed for the long-term price of crude oil and the products derived from its refining, reflect varying degrees of success OPEC could have in accomplishing this objective over time.

The "ineffective OPEC cartel" scenario for crude oil assumes that OPEC members are unable to reach a supply agreement, or that "production cheating" and "price discounting" are extensive and all member nations maintain levels of production to meet internal financial and political requirements irrespective of the effect on price. Crude prices will decline to a level which equates free world supply and demand and forces all marginal producers to shut-in production. Crude oil prices of about $10/barrel in constant 1989 dollars, will result in severe reductions in the exploration and development activities in most non-OPEC countries, particularly in the United States, resulting in more dependence on low cost OPEC supplies, mainly from the Middle East. Although the initial free world demand response to low prices may be limited due to existing efficiencies, energy conservation programs and consumer habits, free world consumption should increase moderately in the early 1990's, reflecting changes in consumer habits in response to an extended period of low prices. This increase in demand is assumed to be met by production from the lowest cost supply source under this scenario, primarily Middle East OPEC countries, resulting in oil prices in real dollars remaining at pre-1973 levels throughout the planning horizon due to the abundant low cost reserves in the Middle East.

Although the outcome of this "ineffective OPEC cartel" scenario will be a concentration of supply into a few high resource Middle Eastern countries, in a manner similar to that which existed in the 1970's, this scenario assumes that these countries will not take advantage of their oligopoly or monopoly position and will keep petroleum prices low for an extended period of time. This policy will ensure long-term world petroleum demand growth, and reduce the incentive for supply competition from non-OPEC producers, fuel switching by utilities and development of alternative fuel technologies.

The most likely or base case scenario for crude oil assumes that a production sharing agreement between all OPEC members with varying degrees of adherence will exist throughout the thirty year forecasting horizon. Although non-OPEC countries will continue to produce at or near capacity, current and projected world petroleum prices, which are significantly lower than experienced in the early 1980's, will result in a reduction in the exploration and development activities in most non-OPEC countries and a steady decline by the early 1990's in non-OPEC supplies, particularly in the United States. From the mid-1990's to early 2000's, the decline in non-OPEC supply should gradually be reversed as increasing world oil prices stimulate non-OPEC exploration and development activities. By the late 2000's, however, non-OPEC production should peak again and begin to decline for the remainder of the planning horizon.

Although the initial free world demand response to relatively low prices may be limited due to existing efficiencies, conservation programs and consumer habits, free world consumption should increase moderately in the early 1990's reflecting changes in consumer habits in response to an extended period of relatively low prices. As free world demand rises and non-OPEC production falls due to near term reductions in exploration and development activities, OPEC will gradually regain control of the market by the early 1990's and the real price of oil should rise through the 1990's. The rate of increase in the real price of oil should diminish in the late 1990's as the resurgence in non-OPEC supply offers some additional competition to OPEC. The rate of increase in the real price of oil should diminish even further after the year 2000, as competition from alternative sources of energy replaces non-OPEC as the limiting factor on OPEC's ability to raise prices.

The "effective OPEC cartel" scenario for crude oil assumes a strong supply agreement is reached between all OPEC and some non-OPEC countries, which restricts world oil supply to a level sufficient to force supply and demand to equilibrate at a higher price than current levels. Although higher prices offer incentives for non-OPEC countries to increase their exploration and development expenditures, this scenario assumes that they are unsuccessful in their finding efforts and that non-OPEC production declines. The scenario assumes that the rate of growth in demand for oil decreases in response to high prices and that consumers switch away from oil and natural gas to lower cost energy sources. The real price of oil should rise rather rapidly reflecting a strict adherence to a strong OPEC supply agreement. By the turn of the century, however, the rate of increase in real price decreases as competition arises from alternative energy sources.

Relationship Between Crude, Residual And Distillate Fuels

The price of residual and distillate fuel oil, besides being influenced by the price of crude oil, is influenced by the operating decisions of the petroleum refining industry (supply) and the market demand for each product. Long-term product mix and availability is determined by the relative value of products which can be manufactured from a barrel of crude oil.

Assuming the most likely or base case crude oil scenario develops, residual fuel oil should generally sell at a discount to crude oil since the refining of crude oil will generally produce a higher percentage of lighter, higher market valued products at lower unit costs, than will the upgrading of residual fuel. The magnitude of this discount will be bound by the non-switchable demand for residual (i.e., the demand by those consumers who cannot utilize alternative fuels). This demand will support a price which will eventually make refiners indifferent between installing additional product upgrading capability or selling residual fuel.

Assuming that the most likely crude oil scenario develops, distillate fuel oil should generally sell at a premium to crude oil because of the strong and increasing demand for the product, especially as a transportation fuel, and the limited supply capability of refineries to meet this growing demand.

The relative degree of success achieved by the OPEC countries in controlling the crude oil market, coupled with refiners' capacity to supply fuel oil and market demand, will establish the range of scenarios for residual and distillate fuel oil. Should OPEC be unsuccessful in achieving an effective supply agreement among its own members, an "ineffective OPEC cartel" scenario for crude oil could result. As world crude oil prices drop, residual fuel oil could briefly sell at a slight premium to crude oil, reflecting a sharp increase in demand for residual fuel oil from fuel switching utilities and industries, and insufficient supply without a corresponding increase in supply. Over time, residual fuel would sell at almost the same price as crude oil, reflecting a strong demand for residual fuel oil at a relatively low price, as compared to alternative fuels. Distillate fuel oil would sell at an even higher premium to crude oil, reflecting the growth in demand for this product with limited refinery capacity.

Should OPEC become very successful in gaining tight control of the crude oil market by achieving a strong supply agreement among its members and some non-OPEC countries, an "effective OPEC cartel" scenario for crude oil could result. Residual fuel oil would sell at a larger discount to crude oil, although still higher in price than in the base case, and this discount would increase with time as rising oil prices justify capital investments for additional fuel switching capability by large industrial and utility end users resulting in lower demand for residual fuel oil. Similarly, distillate fuel oil would sell at a smaller premium as alternative transportation fuels are made available.

<u>Potential For Disruption</u>

As part of the process of preparing a fuel price and availability forecast, FPL assesses the availability of fuel supply and the potential for disruptions. The total crude oil and natural gas liquids production capacities of OPEC and non-OPEC countries, excluding the Centrally Planned Economies (CPE), are expected to increase from about a total of 57 million barrels per day in 1988 to about 65 million barrels per day by 2018. This projection assumes no new significant petroleum discoveries after 1988, depletion of existing wells to continue at historical rates, and additional wells drilled, and tankage, pipeline and dockage facilities added to existing petroleum fields, primarily in the Middle East, when needed. World demand, excluding the CPE, is expected to increase from about 47 million barrels per day in 1988 to about 63 million barrels per day in 2018. Therefore, the world supply of crude oil is expected to be sufficient to meet world demand through the year 2018, even without significant new discoveries.

Although very little is known about the production capability of the CPE, history has shown that the production of crude oil for export is one of the primary means to generate required hard currency for grain purchases and defense efforts. In this light, FPL's long-term supply and demand balance for oil assumes that the CPE's will continue to export crude oil at about today's level through 2018, substituting natural gas and other fuels to meet their domestic requirements, to ensure a steady stream of required hard currency.

Ample refining capacity (inputs to distillation) exists today to process crude oil into refined products to meet free world demand. Free world refining capacity was about 66 million barrels per day in 1980. Due to reduced demand, approximately 10 million barrels per day of that capacity has been shut down in the last nine years. About half of this shutdown capacity could easily be returned to service if required. In addition, approximately 3 million barrels per day of new distillation capacity has recently been constructed in the free world. Therefore, assuming that no other distillation capacity is added during the 1990 to 2018 period, total installed refinery distillation capacity should be about 64 million barrels per day in 2018. Although additional secondary or product upgrading units may be needed from time to time to meet ever changing product specifications, with free world demand projected at 63 million barrels per day, refinery capacity should exist to meet the anticipated refined product demand through the year 2018.

Although there always exists a potential for a disruption in crude oil supply, changes in the world energy picture have occurred since the 1970's which should significantly soften the impact of a future disruption. These changes are shown in Table D.1.

Changes In The World Energy Picture Since The 1970's

1. A significant increase in pipeline capacity out of the Persian Gulf, avoiding the Straits of Hormuz.
2. A significant increase and diversification in non-OPEC crude oil supplies, including the development of the North Sea oil fields, the completion of the Trans Alaskan Pipeline, the development of the Mexican oil fields, the resumption of Canadian oil exports and the development of China as a net exporter of crude oil.
3. An increase in fuel users' capability to switch fuels and a significant increase in the number of coal and nuclear generating facilities.
4. An increase in fuel users' awareness of conservation.
5. The development and application of technology to improve energy efficiency in appliances and other equipment.
6. The development of the U.S. Strategic Petroleum Reserve. As a result, it is expected that even if a disruption occurs, the impact would be effectively offset and therefore, minimal.

Table D.1

Natural Gas

Assuming a market environment where the most likely or base case scenario for crude oil and the corresponding scenario for residual fuel oil develops, the market price of natural gas should be competitive with residual fuel oil in the boiler fuel market in the long-term because of the ability of industrial and utility end users to switch fuels with minimal investments. Currently, the existence of a natural gas deliverability surplus or a "natural gas bubble" has and should continue to create, for about another year, some competition between natural gas producers independent of residual fuel oil prices, primarily in the summer. The impact of this current deliverability surplus, when coupled with the reductions in domestic exploration and development expenditures assumed in the most likely crude oil scenario, should result in a decline in the long-term supply of domestic natural gas.

It should be noted that crude oil is a worldwide produced commodity, easily and economically transported from abundant low cost reserves in the Middle East to the demand centers of the world. Natural gas is also produced worldwide, however, current transportation technology basically limits industry's capabilities to deliver and receive natural gas to pipeline movements. Although increasing pipeline imports from Canada and LNG imports to fill existing receiving capability was assumed in the natural gas supply balance, natural gas is still primarily domestic sourced and will sustain a much more severe impact from reduced domestic exploration and development activities than will oil. Over time, natural gas market prices will rise faster than residual fuel oil prices, reflecting this reduction in supply. By the turn of the century, market natural gas prices will approach, and within the first decade of the twenty-first century exceed, residual fuel oil prices.

Should the "ineffective OPEC cartel" scenario for crude oil and the corresponding scenario for residual fuel oil develop, market natural gas prices should initially remain competitive with residual fuel oil prices. Over time, market natural gas prices will approach, and by the mid-1990's exceed, residual fuel prices as severely reduced domestic exploration and development activity significantly reduces the long-term availability of domestic natural gas.

Assuming the "effective OPEC cartel" scenario for crude oil and the corresponding scenario for residual fuel oil develops, natural gas supplies would decline rapidly, due to the lack of success in domestic exploration activities assumed in this scenario and concurrently, natural gas will slowly lose the boiler fuel market to alternate fuels. Over time, market natural gas prices will approach, and by the turn of the century, exceed residual fuel prices as a lack of success in domestic exploration and development activities significantly reduces the long term availability of domestic natural gas.

FPL's current long-term forecast for natural gas prices used in this study reflects our forecast of market residual fuel oil and natural gas, and the existing contract arrangements between Amoco, Florida Gas Transmission and FPL through the fourth quarter of 1989. With the assumed FERC approval of FGT's open access certificate by January 1, 1990, FPL will start to receive a firm supply of natural gas at a competitive market price.

With regard to specific natural gas volumes delivered to FPL, FPL has assumed the availability of about 350 to 400 million cubic feet per day of natural gas on an average annual basis from the expanded pipeline system through the year 2018.

Potential For Disruption

FPL also assessed the availability of natural gas and the potential for disruption. Currently, there exists a one trillion cubic feet per year deliverability surplus or "natural gas bubble" in the United States. Within the next year, FPL anticipates that this surplus will disappear and the supply and demand for natural gas will be in balance. This balance in natural gas supply and demand and the accompanying firming of natural gas prices are expected to result in some increase in natural gas exploration and development activity, which should help control or reduce the decline in long-term natural gas supply. By the early part of the next century, however, domestic natural gas supply will resume its rapid decline as the production of domestic natural gas becomes more costly.

Although there always exists a potential for a natural gas disruption, industry's flexibility to switch fuels in boilers which can burn both natural gas and oil (which amounts to about 30% of the U.S. natural gas market) will significantly soften the impact of any such disruption. In terms of price, if supply tightens due to a disruption, higher natural gas prices will result, but the impact will be minimal to fuel switching utilities.

Mine Mouth Coal

The primary factor that differentiates the most likely or base case mine-mouth coal price forecast from the alternate coal price scenarios is the degree of success the domestic coal industry will have in increasing or maintaining their share of the boiler fuel market at the expense of oil and natural gas.

On the supply side, the domestic coal market today is very competitive and is expected to remain competitive for many years. The market is characterized by many small companies with abundant reserves lasting well beyond the forecasted period and excess production capacity in all sulfur grades. With many suppliers competing for a given market, miners will reduce their price or if market price falls below their marginal cost of production, close down their mines. By the late 1990's, the supply from active mines and industry demand should be in balance. As demand increases beyond this point, the real mine mouth price of coal will increase slightly as the cost and ability of industry to open new mines will place upward pressure on the real mine mouth cost of coal.

Due to the stability of supply, all mine mouth coal scenarios assumed the same supply scenario for coal. On the demand side, the base case or most likely scenario for mine mouth coal prices, consistent with the most likely scenario for oil and natural gas prices, assumed that the demand for coal will remain stable through the mid-1990's, then increase slowly to only partially fill the additional capacity requirements in the boiler fuel markets. The balance of the capacity requirements in the utility industry will be filled by natural gas and oil fired additions. The "low mine mouth coal price" scenario for coal prices, consistent with the "ineffective OPEC cartel" scenario for oil and natural gas prices, assumed that the demand for coal would remain stable through the late 1990's and then increase only slightly as the boiler fuel market responds to the lower cost of alternate fuels. Finally, the "high mine mouth coal price" scenario, consistent with the "effective OPEC cartel" scenario for oil and natural gas prices, assumed the demand for coal would remain stable through the early 1990's, then increase rapidly to fill the additional capacity requirements in the boiler fuel market as end-users switch from higher cost oil and natural gas alternatives to coal.

Combining the supply and demand scenarios for coal, nominal coal prices in the "low mine mouth coal price" scenario will tend to be slightly lower than in the base case or most likely scenario, as the coal industry tries to maintain market share in light of the relatively low cost of oil. In the "high mine mouth coal price" scenario, nominal coal prices tend to increase only slightly, compared with coal prices in the base case scenario, in an attempt to capture some of the increase in the cost of oil and natural gas without giving up its market share to a competing coal company.

Three grades of coal, representing the most likely sulfur grade and source location, were forecasted for long-term planning purposes: low sulfur coal from southeastern West Virginia (0.8% sulfur; 12,000 BTU/lb), medium sulfur coal from eastern Kentucky (1.6% sulfur; 12,500 BTU/lb), and high sulfur coal from northern West Virginia (3.0% sulfur; 13,000 BTU/lb). For purposes of this study, high sulfur coal was used because of the assumption that new coal fired power plants would be equipped with FGD's or other SO_2 control systems.

Coal Transportation

A most likely scenario was developed for the transportation of coal from the mines in West Virginia to Florida based on the availability and accessibility of competitive transportation alternatives at the selected site. This scenario assumed that competitive modes of transportation would be available to the proposed site, resulting in real rate escalations being only a function of the anticipated real increase in the cost of distillate fuel oil.

The high and low coal price scenarios used in this planning study assumed the same coal transportation scenario as in the most likely case and only varied in the real price change in distillate fuel oil and the GNP implicit price deflator to ensure consistency in all fuel forecasts.

Conclusion

The final step in FPL's fuel price forecasting process involves a review to ensure that the integrated forecast is reasonable and valid for planning purposes given the assumptions and anticipated developments included in the energy scenarios described above, and that the various components of the forecast are compatible with one another in terms of supply and demand balances for the various fuels and relative shares of the world energy market. FPL's review confirmed that the individual forecasts are reasonable and internally consistent and that projected price differentials reflect generally expected trends in the energy environment.

In summary, FPL's long-term nominal fuel price and availability forecast, which was used in this planning study, indicates that residual fuel oil prices will increase rapidly during the 1990's as OPEC regains market control. The rate of increase will be less rapid in the 21st century as the resurgence in non-OPEC supply and the emergence of competitive alternative energy sources dampens OPEC's ability to raise prices. Natural gas prices should remain competitive with residual fuel in the boiler fuel market through the turn of the century. Delivered coal prices will escalate only slightly over time, primarily reflecting the abundance of reserves, and competition in the coal transportation sector. These projected trends result in a widening in the nominal price differential between oil and coal over time.

Figures D.1 through D.4 graph the nominal fuel prices for distillate fuel oil, natural gas, and coal for the most likely, ineffective and effective OPEC cartel and oil shock scenarios. Tables D.2 through D.9 list the projected fuel prices for the 1989 to 2018 period for each scenario.

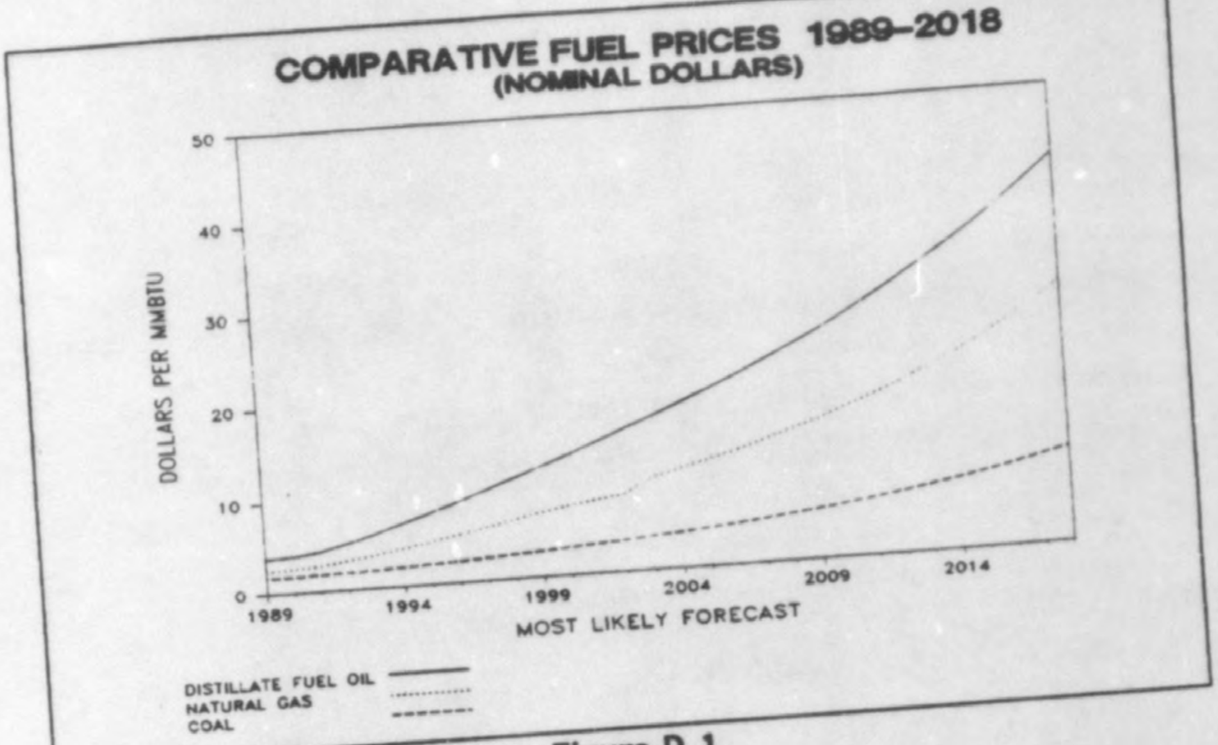


Figure D.1

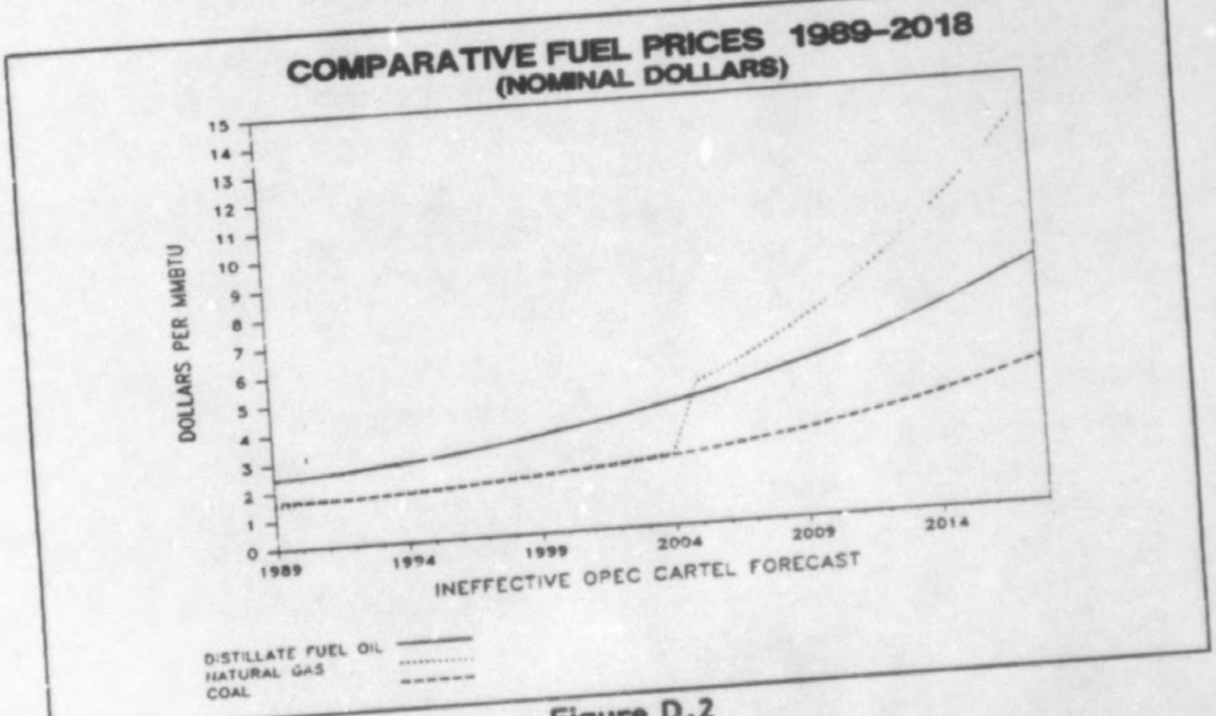


Figure D.2

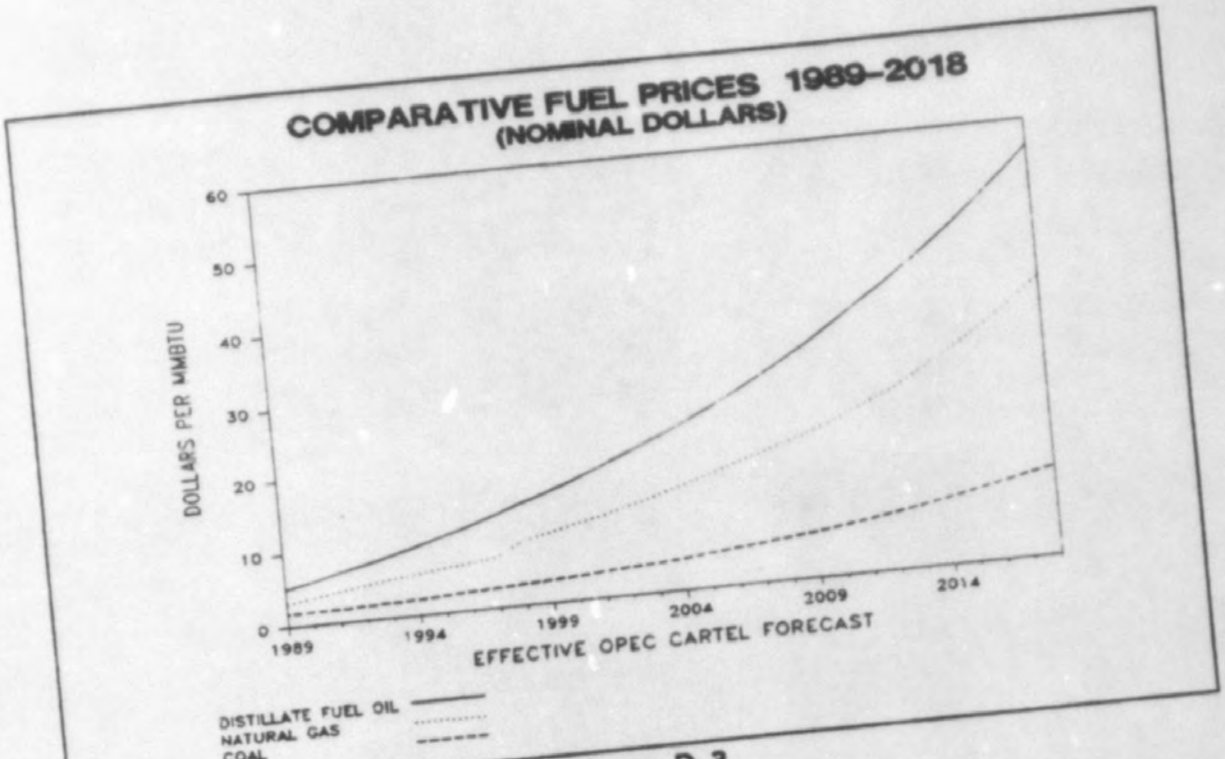


Figure D.3

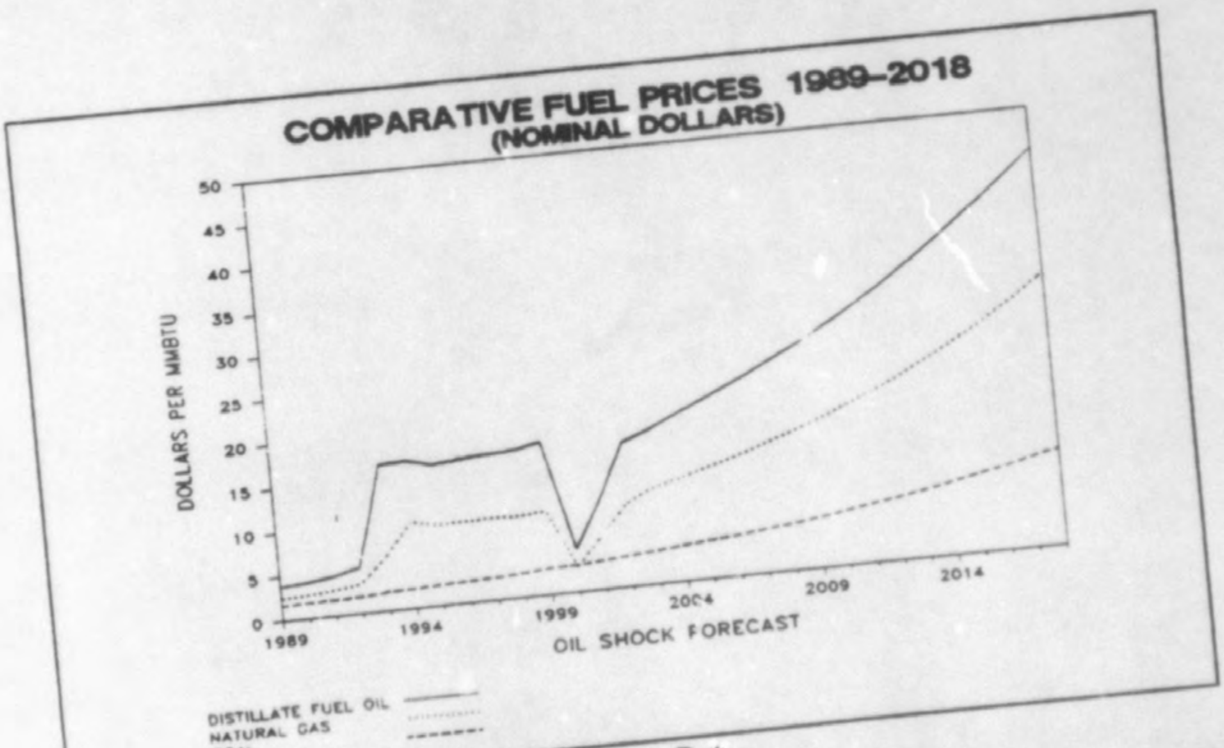


Figure D.4

TABLE D.2

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU

MOST LIKELY SCENARIO

YEAR	DISTILLATE FUEL OIL $/BBL 1989$	DISTILLATE FUEL OIL $/BBL NOMINAL	DISTILLATE FUEL OIL $/MMBTU 1989$	DISTILLATE FUEL OIL $/MMBTU NOMINAL	0.7% SULFUR FUEL OIL $/BBL 1989$	0.7% SULFUR FUEL OIL $/BBL NOMINAL	0.7% SULFUR FUEL OIL $/MMBTU 1989$	0.7% SULFUR FUEL OIL $/MMBTU NOMINAL	1.0% SULFUR FUEL OIL $/BBL 1989$	1.0% SULFUR FUEL OIL $/BBL NOMINAL	1.0% SULFUR FUEL OIL $/MMBTU 1989$	1.0% SULFUR FUEL OIL $/MMBTU NOMINAL
1989	22.50	22.50	3.86	3.86	18.45	18.45	2.90	2.90	17.95	17.95	2.82	2.82
1990	22.08	23.02	3.79	3.95	17.85	18.60	2.80	2.92	17.37	18.10	2.73	2.85
1991	23.33	25.37	4.00	4.35	18.27	19.84	2.87	3.11	17.78	19.31	2.80	3.04
1992	26.14	29.69	4.48	5.09	20.01	22.70	3.14	3.56	19.47	22.08	3.06	3.47
1993	29.17	34.56	5.00	5.93	21.84	25.83	3.43	4.05	21.25	25.12	3.34	3.95
1994	32.25	40.05	5.53	6.87	23.93	29.65	3.76	4.65	23.28	28.83	3.66	4.53
1995	35.05	45.72	6.01	7.84	25.85	33.63	4.06	5.28	25.14	32.69	3.95	5.14
1996	37.57	51.63	6.44	8.86	27.55	37.76	4.32	5.93	26.79	36.71	4.21	5.77
1997	39.80	57.68	6.83	9.89	29.02	41.95	4.56	6.59	28.22	40.78	4.44	6.41
1998	41.73	63.82	7.16	10.95	30.27	46.18	4.75	7.25	29.43	44.89	4.63	7.06
1999	43.36	70.05	7.44	12.01	31.29	50.43	4.91	7.92	30.42	49.01	4.78	7.71
2000	44.81	76.52	7.69	13.13	32.17	54.81	5.05	8.61	31.28	53.28	4.92	8.38
2001	46.14	83.15	7.91	14.26	32.97	59.27	5.18	9.30	32.05	57.60	5.04	9.06
2002	47.27	89.88	8.11	15.42	33.61	63.76	5.28	10.01	32.67	61.96	5.14	9.74
2003	48.23	96.58	8.27	16.57	34.14	68.19	5.36	10.71	33.18	66.27	5.22	10.42
2004	49.22	103.80	8.44	17.80	34.67	72.94	5.44	11.45	33.70	70.89	5.30	11.15
2005	50.07	111.19	8.59	19.07	35.11	77.78	5.51	12.21	34.13	75.59	5.37	11.88
2006	50.85	118.81	8.72	20.38	35.49	82.73	5.57	12.99	34.50	80.40	5.42	12.64
2007	51.56	126.73	8.84	21.74	35.83	87.85	5.62	13.79	34.82	85.38	5.48	13.42
2008	52.21	135.02	8.96	23.16	36.12	93.19	5.67	14.63	35.11	90.56	5.52	14.24
2009	52.78	143.61	9.05	24.63	36.36	98.68	5.71	15.49	35.34	95.90	5.56	15.08
2010	53.37	152.77	9.15	26.20	36.61	104.53	5.75	16.41	35.58	101.58	5.59	15.97
2011	53.88	162.25	9.24	27.83	36.80	110.54	5.78	17.35	35.77	107.42	5.62	16.89
2012	54.39	172.31	9.33	29.56	36.99	116.90	5.81	18.35	35.95	113.60	5.65	17.86
2013	54.92	183.03	9.42	31.39	37.19	123.65	5.84	19.41	36.15	120.16	5.68	18.89
2014	55.43	194.36	9.51	33.34	37.38	130.76	5.87	20.53	36.33	127.07	5.71	19.98
2015	55.94	206.37	9.60	35.40	37.57	138.27	5.90	21.71	36.52	134.37	5.74	21.13
2016	56.48	219.18	9.69	37.60	37.78	146.25	5.93	22.96	36.72	142.12	5.77	22.35
2017	57.00	232.71	9.78	39.92	37.97	154.65	5.96	24.28	36.91	150.29	5.80	23.63
2018	57.47	246.68	9.86	42.31	38.13	163.22	5.99	25.62	37.07	158.60	5.83	24.94

EXHIBIT NO. 2

DOCKET NO.:	960409-EI
WITNESS:	WATERS
DESCRIPTION:	FPL MARTIN 3 AND 4 COST SUMMARY

E

6/4/96

PMG UNITS 3/4
ER SUMMARY

ER#	DESC	CLOSE DATE	$
1158-928	WETLAND MITIGATION	Nov-94	$939,757
6949-928	UNIT 3	Apr-95	$253,712,538
7587-928	UNIT4	Apr-95	$195,264,114
9382-928	PMG PIPELINE	Jul-94	$13,292,886
9087-928	PIPELINE RIGHT-OF-WAY	May-94	$1,259,566
1534-931	WAREHOUSE #2 RELOC	Jul-94	$816,073
1535-931	WAREHOUSE #1 RELOC	Jul-94	$689,525
2173-956	INDIANTOWN WAREHOUSE	Jun-94	$401,530
1428-956	INDIANTOWN WAREHOUSE OFFICE RENOVATION	Feb-93	$108,876
9349-928	OFFICE BLDG RENOVATION	Apr-92	$124,653
9289-984	MARTIN PLANT-CONSTRUCT 500-230KV SYSTEM SWITCHYARD	Dec-94	$19,994,450
9288-984	CONSTRUCT 230KV UNIT 3/4 SWITCHYARD	Dec-94	$4,148,628
2437-984	RELOCATE LINES TO NEW SWITCHYARD	Apr-95	$279,394
3852-918	PMR GAS TIE LINE FR 1/2 TO 3/4	Aug-93	$370,942
3642-928	UNIT 3 PROT & CNTRL SYSTEM	Aug-95	$209,024
3643-928	UNIT 3 PROT & CNTRL SYSTEM	Aug-95	$175,103
3645-928	INSTALL A DISTRIBUTED COMPUTER PROCESSING SYS FOR PMG	Apr-95	$146,451
5241-928	CONTINUOUS EMMISSIONS MONITORING SYS UNIT 4	Jul-95	$406,166
5242-928	CONTINUOUS EMMISSIONS MONITORING SYS UNIT 3	Jul-95	$412,135
6297-928	UNIT 3 ORIG CNST WRAP-UP (COSTS THRU 5-96)	OPEN	$2,305,610
6298-928	UNIT 4 ORIG CNST WRAP-UP (COSTS THRU 5-96)	OPEN	$3,342,193
VARIOUS	PMG CAPITAL SPARES (COSTS THRU 5-95)	VARIOUS	$12,595,220
TOTAL			$510,994,833

\# 448,476,652

\# 62,018,181

\# 510,994,833
448,976,652
62,018,181

EXHIBIT 2 6-10-96

TO SAM

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AUDIT DISCLOSURE 1

SUBJECT: SUMMARY OF CONTRACTS AUDITED

STATEMENT OF FACTS:

Per the audit service request, we are providing the following information.

FPL provided the total amount of Martin Units 3 and 4.

Martin 3	closed 6/95	253,712,538	ER 6949 - 928
Martin 4	Closed 7/95	195,264,114	ER 7587 - 928
	Total	448,976,652	
	TOTAL B/170	510,994,833	Δ 62,018,181

The following is a summary of the contracts audited by PSC staff, detailing the amounts and scope. See next page.

EXHIBIT NO. 3

DOCKET NO.: 960409-EI

WITNESS: WATERS

DESCRIPTION: FPL FUEL PRICE FORECASTS (1990 - 1996)

FPL'S TOTAL FIRM GAS TRANSPORTATION CAPACITY (MMBTU/DAY)

PERIOD	PHASE I	PHASE II	PHASE III
		[illegible]	1995
NOV. - MAR.	244,800	255,000	455,000
APRIL	280,000	280,000	480,000
MAY - SEPT.	392,000	430,000	630,000
OCT.	280,000	280,000	480,000

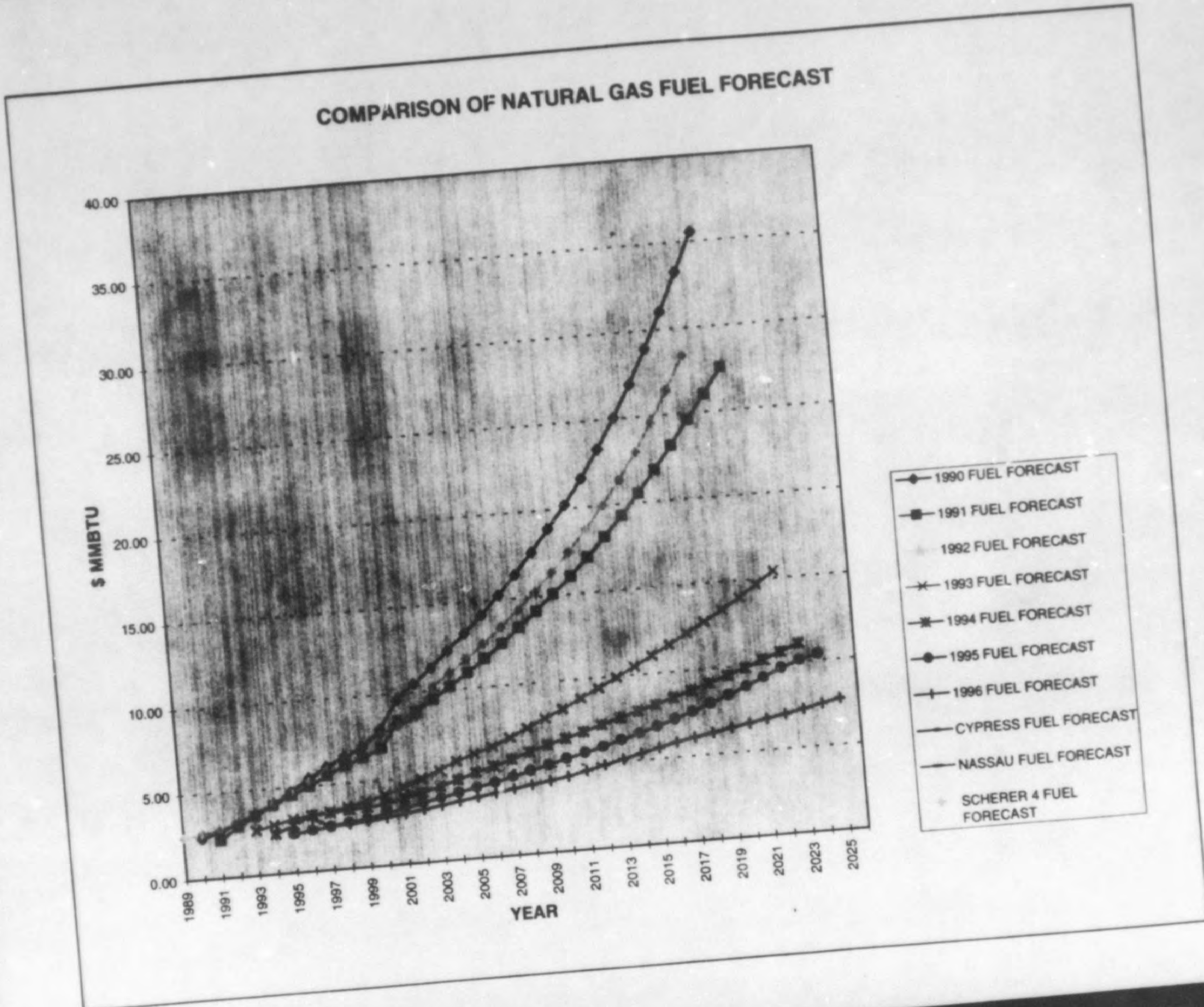
FPL'S TOTAL LONG TERM FIRM GAS SUPPLY (MMBTU/DAY)

PERIOD	PHASE I	PHASE II	INITIAL PHASE III	> 7/99 PHASE III
NOV. - MAR.	244,800	255,000	300,000	132,000
APRIL	280,000	280,000	300,000	132,000
MAY - SEPT.	392,000	430,000	430,000	226,000
OCT.	280,000	280,000	300,000	132,000

NOTES:

1. THE VOLUME THAT WAS ADDED BY EACH PHASE CAN BE CALCULATED BY SUBTRACTING THE PRIOR PHASE.
2. THE EARLIEST TRANSPORT REDUCTION VIA CONTRACT EXPIRATION IS 2005.
3. THE INITIAL PHASE III GAS SUPPLY VOLUMES CAN BE RESTORED BY EXERCISING A CONTRACT OPTION.

H.A. BARTH
6/7/96
FILE: SAMW-VOL.XLS


COMPARISON OF NATURAL GAS FUEL FORECAST
$ MMBTU
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
YEAR
1990 FUEL FORECAST
1991 FUEL FORECAST
1992 FUEL FORECAST
1993 FUEL FORECAST
1994 FUEL FORECAST
1995 FUEL FORECAST
1996 FUEL FORECAST
CYPRESS FUEL FORECAST
NASSAU FUEL FORECAST
SCHERER 4 FUEL FORECAST

6/91 10/91 9/90

	1990 FUEL FORECAST	1991 FUEL FORECAST	1992 FUEL FORECAST	1993 FUEL FORECAST	1994 FUEL FORECAST	1995 FUEL FORECAST	1996 FUEL FORECAST	CYPRESS FUEL FORECAST	NASSAU FUEL FORECAST	SCHERER 4 FUEL FORECAST
1989										2.48
1990	2.40									2.62
1991	2.72	2.21						2.21	2.21	2.81
1992	3.11	2.94	2.16					2.94	2.94	3.17
1993	3.63	3.49	2.50	2.63				3.49	3.49	3.63
1994	4.17	4.04	2.77	2.89	2.35			4.04	4.04	4.18
1995	4.74	4.53	3.02	3.16	2.78	2.26		4.53	4.53	4.70
1996	5.44	4.97	3.23	3.30	3.28	2.42	3.09	4.97	4.97	5.29
1997	6.02	5.54	3.55	3.44	3.36	2.55	2.57	5.54	5.54	5.89
1998	6.55	6.02	3.87	3.60	3.45	2.72	2.61	6.02	6.02	6.49
1999	6.98	6.41	4.27	3.85	3.51	2.85	2.69	6.41	6.41	7.09
2000	7.94	6.87	4.73	4.14	3.62	3.06	2.82	6.87	6.87	7.66
2001	9.60	8.40	5.21	4.50	3.85	3.29	2.96	8.40	8.40	8.09
2002	10.45	8.84	5.72	4.90	4.11	3.50	3.11	8.84	8.84	8.55
2003	11.32	9.48	6.22	5.32	4.38	3.72	3.27	9.48	9.48	10.18
2004	12.25	10.17	6.72	5.77	4.69	3.94	3.43	10.17	10.17	10.92
2005	13.17	10.88	7.25	6.13	5.03	4.16	3.59	10.88	10.88	11.69
2006	14.17	11.64	7.90	6.46	5.31	4.37	3.74	11.64	11.64	12.51
2007	15.25	12.43	8.55	6.90	5.63	4.61	3.90	12.43	12.43	13.37
2008	16.37	13.27	9.14	7.39	5.97	4.87	4.05	13.27	13.27	14.29
2009	17.59	14.14	9.77	7.86	6.29	5.14	4.22	14.14	14.14	15.26
2010	18.87	15.06	10.40	8.32	6.60	5.42	4.39	15.06	15.06	16.32
2011	20.19	16.02	10.99	8.86	6.91	5.69	4.63	16.02	16.02	17.44
2012	21.67	17.06	11.61	9.37	7.22	5.96	4.88	17.06	17.06	18.65
2013	23.30	18.15	12.26	9.92	7.55	6.25	5.14	18.15	18.15	19.97
2014	25.06	19.32	12.96	10.46	7.85	6.56	5.39	19.32	19.32	21.39
2015	26.92	20.55	14.28	11.04	8.15	6.88	5.64	20.55	20.55	22.93
2016	28.92	21.85	15.08	11.59	8.48	7.22	5.89	21.85	21.85	24.61
2017	31.02	23.20	15.91	12.15	8.80	7.58	6.08	23.20	23.20	26.42
2018	33.24	24.60	16.78	12.74	9.14	7.97	6.26	24.60	24.60	28.36
2019	35.54	26.03	17.70	13.35	9.51	8.37	6.44	26.03	26.03	
2020		27.51	18.70	14.00	9.87	8.80	6.62			
2021			19.65	14.68	10.25	9.24	6.82			
2022				15.39	10.64	9.72	7.01			
2023					11.05	10.08	7.22			
2024						10.37	7.44			
2025							7.68			

EXHIBIT 3

6-10-96

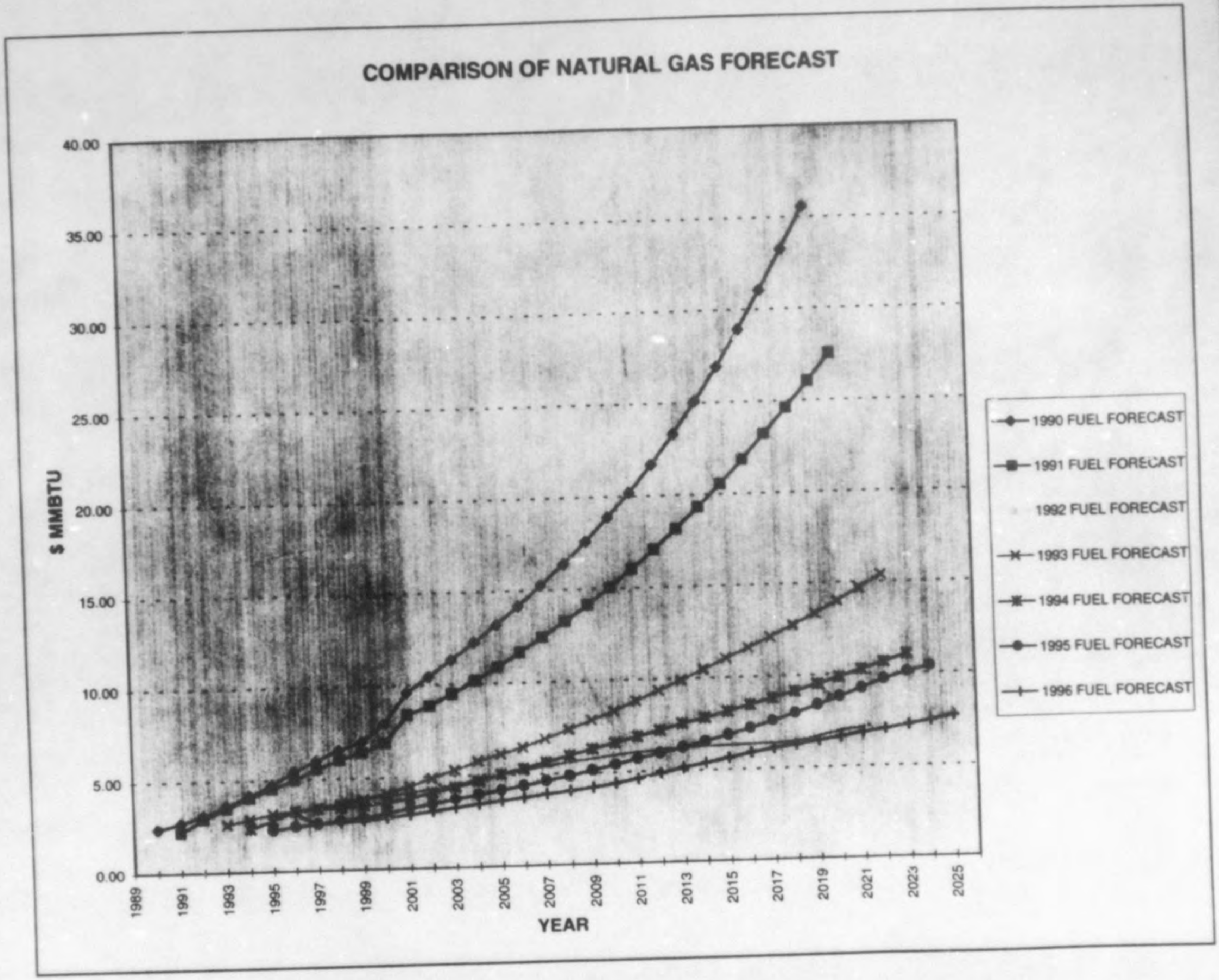


TABLE D.4

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU

EFFECTIVE OPEC CARTEL SCENARIO

YEAR	DISTILLATE FUEL OIL				0.7% SULFUR FUEL OIL				1.0% SULFUR FUEL OIL			
	$/BBL		$/MMBTU		$/BBL		$/MMBTU		$/BBL		$/MMBTU	
	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL
1989	30.25	30.25	5.19	5.19	23.29	23.29	3.66	3.66	22.57	22.57	3.55	3.55
1990	32.35	34.16	5.55	5.86	24.88	26.26	3.91	4.12	24.11	25.44	3.79	4.00
1991	35.65	39.90	6.11	6.84	27.39	30.62	4.30	4.81	26.53	29.66	4.17	4.66
1992	37.75	44.60	6.48	7.65	28.98	34.19	4.55	5.37	28.07	33.11	4.41	5.21
1993	39.87	49.69	6.84	8.52	30.34	37.74	4.76	5.93	29.39	36.55	4.62	5.75
1994	42.02	55.20	7.21	9.47	31.38	41.12	4.93	6.46	30.38	39.80	4.78	6.26
1995	44.19	61.21	7.58	10.50	32.73	45.20	5.14	7.10	31.68	43.75	4.98	6.88
1996	46.09	67.31	7.91	11.54	33.85	49.30	5.31	7.74	32.77	47.71	5.15	7.50
1997	48.01	73.92	8.24	12.68	34.98	53.70	5.49	8.43	33.86	51.97	5.32	8.17
1998	49.96	81.10	8.57	13.91	36.10	58.45	5.67	9.18	34.95	56.56	5.49	8.89
1999	51.62	88.25	8.85	15.14	37.00	63.10	5.81	9.91	35.82	61.06	5.63	9.60
2000	53.29	95.97	9.14	16.46	37.90	68.08	5.95	10.69	36.69	65.88	5.77	10.36
2001	54.99	104.30	9.43	17.89	38.39	72.62	6.03	11.40	37.14	70.24	5.84	11.04
2002	56.70	113.27	9.73	19.43	39.28	78.26	6.17	12.29	38.00	75.69	5.97	11.90
2003	58.11	122.14	9.97	20.95	39.94	83.74	6.27	13.15	38.65	81.00	6.08	12.74
2004	59.53	131.66	10.21	22.58	40.61	89.58	6.38	14.06	39.29	86.64	6.18	13.62
2005	60.97	141.87	10.46	24.33	41.28	95.80	6.48	15.04	39.94	92.66	6.28	14.57
2006	62.42	152.82	10.71	26.21	41.95	102.43	6.58	16.08	40.58	99.07	6.38	15.58
2007	63.55	163.54	10.90	28.05	42.39	108.80	6.65	17.08	41.01	105.23	6.45	16.55
2008	64.69	174.98	11.10	30.01	42.84	115.56	6.72	18.14	41.44	111.77	6.52	17.57
2009	65.84	187.19	11.29	32.11	42.81	121.39	6.72	19.06	41.40	117.36	6.51	18.45
2010	67.00	200.23	11.49	34.34	43.25	128.91	6.79	20.24	41.83	124.63	6.58	19.60
2011	68.17	214.14	11.69	36.73	43.69	136.87	6.86	21.49	42.25	132.33	6.64	20.81
2012	69.00	227.81	11.84	39.08	43.91	144.59	6.89	22.70	42.46	139.78	6.68	21.98
2013	69.84	242.35	11.98	41.57	44.13	152.73	6.93	23.98	42.68	147.66	6.71	23.22
2014	70.68	257.79	12.12	44.22	44.35	161.33	6.96	25.33	42.89	155.97	6.74	24.52
2015	71.52	273.94	12.27	46.99	44.57	170.25	7.00	26.73	43.10	164.59	6.78	25.88
2016	72.37	291.08	12.41	49.93	44.79	179.66	7.03	28.20	43.31	173.69	6.81	27.31
2017	73.23	309.27	12.56	53.05	45.01	189.59	7.07	29.76	43.53	183.29	6.84	28.82
2018	74.09	328.38	12.71	56.33	45.23	199.87	7.10	31.38	43.74	193.22	6.88	30.38

TABLE D.3

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU

INEFFECTIVE OPEC CARTEL SCENARIO

	DISTILLATE FUEL OIL				0.7% SULFUR FUEL OIL				1.0% SULFUR FUEL OIL			
	$/BBL		$/MMBTU		$/BBL		$/MMBTU		$/BBL		$/MMBTU	
YEAR	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL
1989	14.45	14.45	2.48	2.48	11.75	11.75	1.84	1.84	11.45	11.45	1.80	1.80
1990	14.45	14.76	2.48	2.53	11.75	12.00	1.84	1.88	11.45	11.69	1.80	1.84
1991	14.45	15.03	2.48	2.58	11.75	12.21	1.84	1.92	11.45	11.90	1.80	1.87
1992	14.55	15.49	2.50	2.66	11.75	12.50	1.84	1.96	11.45	12.18	1.80	1.91
1993	14.65	15.99	2.51	2.74	11.75	12.81	1.84	2.01	11.45	12.48	1.80	1.96
1994	14.75	16.53	2.53	2.84	11.75	13.14	1.84	2.06	11.45	12.81	1.80	2.01
1995	14.85	17.10	2.55	2.93	11.75	13.50	1.84	2.12	11.45	13.15	1.80	2.07
1996	14.95	17.80	2.56	3.05	11.75	13.97	1.84	2.19	11.45	13.61	1.80	2.14
1997	15.05	18.53	2.58	3.18	11.75	14.45	1.84	2.27	11.45	14.08	1.80	2.21
1998	15.15	19.31	2.60	3.31	11.75	14.97	1.84	2.35	11.45	14.58	1.80	2.29
1999	15.25	20.17	2.62	3.46	11.75	15.54	1.84	2.44	11.45	15.15	1.80	2.38
2000	15.35	21.07	2.63	3.61	11.75	16.14	1.84	2.53	11.45	15.73	1.80	2.47
2001	15.45	22.01	2.65	3.78	11.75	16.76	1.84	2.63	11.45	16.33	1.80	2.57
2002	15.55	22.99	2.67	3.94	11.75	17.40	1.84	2.73	11.45	16.96	1.80	2.67
2003	15.65	24.07	2.68	4.13	11.75	18.11	1.84	2.84	11.45	17.65	1.80	2.78
2004	15.75	25.20	2.70	4.32	11.75	18.85	1.84	2.96	11.45	18.37	1.80	2.89
2005	15.85	26.38	2.72	4.53	11.75	19.62	1.84	3.08	11.45	19.12	1.80	3.01
2006	15.95	27.62	2.74	4.74	11.75	20.42	1.84	3.21	11.45	19.90	1.80	3.13
2007	16.05	28.98	2.75	4.97	11.75	21.30	1.84	3.34	11.45	20.77	1.80	3.26
2008	16.15	30.41	2.77	5.22	11.75	22.22	1.84	3.49	11.45	21.67	1.80	3.41
2009	16.25	31.92	2.79	5.47	11.75	23.19	1.84	3.64	11.45	22.61	1.80	3.55
2010	16.35	33.49	2.80	5.74	11.75	24.19	1.84	3.80	11.45	23.59	1.80	3.71
2011	16.45	35.14	2.82	6.03	11.75	25.24	1.84	3.96	11.45	24.61	1.80	3.87
2012	16.55	37.00	2.84	6.35	11.75	26.43	1.84	4.15	11.45	25.77	1.80	4.05
2013	16.65	38.96	2.86	6.68	11.75	27.67	1.84	4.34	11.45	26.97	1.80	4.24
2014	16.75	41.01	2.87	7.03	11.75	28.96	1.84	4.55	11.45	28.24	1.80	4.44
2015	16.85	43.18	2.89	7.41	11.75	30.32	1.84	4.76	11.45	29.56	1.80	4.65
2016	16.95	45.45	2.91	7.80	11.75	31.74	1.84	4.98	11.45	30.95	1.80	4.87
2017	17.05	47.85	2.92	8.21	11.75	33.23	1.84	5.22	11.45	32.40	1.80	5.09
2018	17.15	50.18	2.94	8.61	11.75	34.60	1.84	5.43	11.45	33.73	1.80	5.30

TABLE D.5

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU

OIL SHOCK SCENARIO

YEAR	DISTILLATE FUEL OIL				0.7% SULFUR FUEL OIL				1.0% SULFUR FUEL OIL			
	$/BBL		$/MMBTU		$/BBL		$/MMBTU		$/BBL		$/MMBTU	
	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL
1989	22.50	22.50	3.86	3.86	18.45	18.45	2.90	2.90	17.95	17.95	2.82	2.82
1990	22.08	23.63	3.79	4.06	17.85	19.10	2.80	3.00	17.37	18.59	2.73	2.92
1991	23.33	26.33	4.00	4.51	18.27	20.62	2.87	3.24	17.78	20.06	2.80	3.16
1992	26.14	31.12	4.48	5.33	20.01	23.82	3.14	3.74	19.47	23.18	3.06	3.64
1993	73.37	96.71	12.56	16.56	52.50	69.21	8.36	11.02	50.71	66.85	7.99	10.53
1994	70.63	97.91	12.09	16.77	50.14	69.50	7.98	11.07	48.43	67.14	7.63	10.57
1995	65.17	94.18	11.16	16.13	45.39	65.59	7.23	10.44	43.82	63.33	6.90	9.97
1996	62.99	95.55	10.79	16.36	43.53	66.04	6.93	10.52	42.04	63.77	6.62	10.04
1997	60.75	96.93	10.40	16.60	41.67	66.49	6.64	10.59	40.24	64.21	6.34	10.11
1998	58.52	98.11	10.02	16.80	39.39	66.04	6.27	10.52	38.02	63.75	5.99	10.04
1999	57.62	101.56	9.87	17.39	38.49	67.85	6.13	10.80	37.16	65.50	5.85	10.31
2000	16.10	28.70	2.76	4.91	12.31	21.93	1.96	3.49	11.98	21.35	1.89	3.36
2001	31.29	59.44	5.36	10.18	23.48	44.60	3.74	7.10	22.83	43.37	3.60	6.83
2002	47.27	95.50	8.11	16.39	33.61	67.91	5.48	11.07	32.67	66.01	5.14	10.38
2003	48.23	102.66	8.27	17.60	34.14	72.67	5.56	11.83	33.18	70.62	5.22	11.11
2004	49.22	110.42	8.44	18.93	34.67	77.78	5.44	12.20	33.70	75.60	5.30	11.89
2005	50.07	118.23	8.59	20.28	35.11	82.91	5.51	13.01	34.13	80.59	5.37	12.68
2006	50.85	126.45	8.72	21.68	35.49	88.26	5.57	13.85	34.50	85.79	5.42	13.48
2007	51.56	135.00	8.84	23.15	35.83	93.81	5.62	14.71	34.82	91.17	5.48	14.35
2008	52.21	144.08	8.96	24.73	36.12	99.68	5.67	15.65	35.11	96.89	5.52	15.23
2009	52.78	153.47	9.05	26.32	36.36	105.73	5.71	16.60	35.34	102.76	5.56	16.17
2010	53.37	163.54	9.15	28.04	36.61	112.18	5.75	17.62	35.58	109.03	5.59	17.13
2011	53.88	173.98	9.24	29.84	36.80	118.83	5.78	18.66	35.77	115.50	5.62	18.15
2012	54.39	185.08	9.33	31.75	36.99	125.87	5.81	19.77	35.95	122.33	5.65	19.23
2013	54.92	196.81	9.42	33.76	37.19	133.27	5.84	20.93	36.15	129.54	5.68	20.35
2014	55.43	209.15	9.51	35.88	37.38	141.04	5.87	22.15	36.33	137.08	5.71	21.55
2015	55.94	221.94	9.60	38.09	37.57	149.06	5.90	23.41	36.52	144.89	5.74	22.77
2016	56.48	235.48	9.69	40.40	37.78	157.52	5.93	24.72	36.72	153.10	5.77	24.06
2017	57.00	249.76	9.78	42.85	37.97	166.37	5.96	26.11	36.91	161.73	5.80	25.41
2018	57.47	264.37	9.86	45.36	38.13	175.40	5.99	27.55	37.07	170.53	5.83	26.82

TABLE D.5

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU

INEFFECTIVE OPEC CARTEL SCENARIO

YEAR	INTERRUPTIBLE NATURAL GAS $/MMBTU 1989$	INTERRUPTIBLE NATURAL GAS $/MMBTU NOMINAL	FIRM NATURAL GAS $/MMBTU 1989$	FIRM NATURAL GAS $/MMBTU NOMINAL	AVERAGE NATURAL GAS $/MMBTU 1989$	AVERAGE NATURAL GAS $/MMBTU NOMINAL
1989	1.51	1.51	2.21	2.21	1.54	1.54
1990	1.51	1.54	1.59	1.62	1.58	1.61
1991	1.51	1.57	1.60	1.65	1.59	1.65
1992	1.51	1.61	1.60	1.70	1.59	1.69
1993	1.51	1.65	1.61	1.74	1.60	1.73
1994	1.51	1.70	1.61	1.79	1.61	1.78
1995	1.51	1.75	1.62	1.84	1.61	1.83
1996	1.51	1.81	1.63	1.90	1.62	1.89
1997	1.51	1.86	1.63	1.96	1.62	1.95
1998	1.51	1.93	1.64	2.03	1.63	2.02
1999	1.51	2.00	1.65	2.10	1.63	2.09
2000	1.51	2.07	1.65	2.18	1.64	2.16
2001	1.51	2.14	1.66	2.25	1.64	2.24
2002	1.51	2.22	1.66	2.33	1.65	2.32
2003	1.51	2.30	1.67	2.43	1.66	2.42
2004	1.51	2.39	1.68	2.52	1.66	2.51
2005	3.00	4.95			3.00	4.95
2006	3.12	5.35			3.12	5.35
2007	3.26	5.82			3.26	5.82
2008	3.39	6.31			3.39	6.31
2009	3.53	6.84			3.53	6.84
2010	3.68	7.44			3.68	7.44
2011	3.83	8.07			3.83	8.07
2012	3.98	8.78			3.98	8.78
2013	4.14	9.53			4.14	9.53
2014	4.29	10.34			4.29	10.34
2015	4.44	11.20			4.44	11.20
2016	4.60	12.12			4.60	12.12
2017	4.75	13.10			4.75	13.10
2018	4.90	14.14			4.90	14.14

MOST LIKELY SCENARIO

YEAR	INTERRUPTIBLE NATURAL GAS $/MMBTU 1989$	INTERRUPTIBLE NATURAL GAS $/MMBTU NOMINAL	FIRM NATURAL GAS $/MMBTU 1989$	FIRM NATURAL GAS $/MMBTU NOMINAL	AVERAGE NATURAL GAS $/MMBTU 1989$	AVERAGE NATURAL GAS $/MMBTU NOMINAL
1989	2.49	2.49	2.21	2.21	2.48	2.48
1990	2.40	2.51	2.54	2.64	2.51	2.62
1991	2.46	2.69	2.61	2.83	2.60	2.81
1992	2.72	3.10	2.81	3.17	2.80	3.17
1993	2.99	3.56	3.08	3.63	3.08	3.63 $3D
1994	3.29	4.12	3.40	4.19	3.39	4.18
1995	3.57	4.70	3.63	4.70	3.63	4.70
1996	3.82	5.29	3.89	5.29	3.89	5.29
1997	4.04	5.89	4.11	5.89	4.11	5.89
1998	4.22	6.50	4.30	6.49	4.30	6.49
1999	4.37	7.10	4.45	7.09	4.45	7.09
2000	4.50	7.73	4.55	7.65	4.56	7.66
2001	4.61	8.36	4.56	8.06	4.57	8.09
2002	4.71	9.01	4.56	8.50	4.59	8.55
2003	5.18	10.18			5.18	10.18
2004	5.28	10.92			5.28	10.92
2005	5.37	11.69			5.37	11.69
2006	5.46	12.51			5.46	12.51
2007	5.55	13.37			5.55	13.37
2008	5.65	14.29			5.65	14.29
2009	5.73	15.26			5.73	15.26
2010	5.83	16.32			5.83	16.32
2011	5.92	17.44			5.92	17.44
2012	6.02	18.65			6.02	18.65
2013	6.13	19.97			6.13	19.97
2014	6.24	21.39			6.24	21.39
2015	6.36	22.93			6.36	22.93
2016	6.49	24.61			6.49	24.61
2017	6.62	26.42			6.62	26.42
2018	6.76	28.36			6.76	28.36

EFFECTIVE OPEC CARTEL SCENARIO

YEAR	INTERRUPTIBLE NATURAL GAS $/MMBTU 1989$	INTERRUPTIBLE NATURAL GAS $/MMBTU NOMINAL	FIRM NATURAL GAS $/MMBTU 1989$	FIRM NATURAL GAS $/MMBTU NOMINAL	AVERAGE NATURAL GAS $/MMBTU 1989$	AVERAGE NATURAL GAS $/MMBTU NOMINAL
1989	3.18	3.18	2.21	2.21	3.14	3.14
1990	3.42	3.62	3.49	3.68	3.48	3.67
1991	3.78	4.25	3.87	4.31	3.86	4.31
1992	4.01	4.77	4.11	4.84	4.10	4.83
1993	4.21	5.28	4.32	5.35	4.31	5.35
1994	4.36	5.77	4.47	5.84	4.47	5.84
1995	4.56	6.36	4.53	6.23	4.54	6.24
1996	4.72	6.95	4.54	6.57	4.56	6.60
1997	4.89	7.58	4.55	6.92	4.58	6.98
1998	5.45	8.90			5.45	8.90
1999	5.62	9.68			5.62	9.68
2000	5.81	10.52			5.81	10.52
2001	5.92	11.31			5.92	11.31
2002	6.11	12.28			6.11	12.28
2003	6.26	13.24			6.26	13.24
2004	6.42	14.28			6.42	14.28
2005	6.58	15.39			6.58	15.39
2006	6.74	16.59			6.74	16.59
2007	6.87	17.76			6.87	17.76
2008	7.00	19.02			7.00	19.02
2009	7.08	20.23			7.08	20.23
2010	7.24	21.75			7.24	21.75
2011	7.41	23.38			7.41	23.38
2012	7.54	25.00			7.54	25.00
2013	7.70	26.85			7.70	26.85
2014	7.87	28.82			7.87	28.82
2015	8.03	30.90			8.03	30.90
2016	8.23	33.26			8.23	33.26
2017	8.44	35.78			8.44	35.78
2018	8.64	38.48			8.64	38.48

TABLE D.7

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

YEAR	INEFFECTIVE OPEC CARTEL SCENARIO			MOST LIKELY SCENARIO			EFFECTIVE OPEC CARTEL SCENARIO			OIL SHOCK SCENARIO		
	INTERRUPTIBLE	FIRM	TOTAL	INTERRUPTIBLE	FIRM	TOTAL	INTERRUPTIBLE	FIRM	TOTAL	INTERRUPTIBLE	FIRM	TOTAL
1989	394	19	413	394	19	413	394	19	413	394	19	413
1990	75	327	402	75	327	402	75	327	402	75	327	402
1991	38	327	365	38	327	365	38	327	365	38	327	365
1992	34	327	361	34	327	361	34	327	361	34	327	361
1993	29	327	356	29	327	356	29	327	356	29	327	356
1994	29	327	356	29	327	356	29	327	356	356		356
1995	29	327	356	29	327	356	29	327	356	356		356
1996	29	327	356	29	327	356	29	327	356	356		356
1997	31	327	358	31	327	358	31	327	358	358		358
1998	34	327	361	34	327	361	361		361	361		361
1999	36	327	363	36	327	363	363		363	363		363
2000	40	327	367	40	327	367	367		367	367		367
2001	33	327	360	33	327	360	370		370	360		360
2002	33	327	360	33	327	360	375		375	360		360
2003	27	327	354	354		354	380		380	354		354
2004	27	327	354	354		354	383		383	354		354
2005	358		358	358		358	386		386	358		358
2006	351		351	351		351	389		389	351		351
2007	360		360	360		360	392		392	360		360
2008	360		360	360		360	395		395	360		360
2009	360		360	360		360	398		398	360		360
2010	360		360	360		360	400		400	360		360
2011	360		360	360		360	402		402	360		360
2012	360		360	360		360	404		404	360		360
2013	360		360	360		360	406		406	360		360
2014	360		360	360		360	408		408	360		360
2015	360		360	360		360	410		410	360		360
2016	360		360	360		360	412		412	360		360
2017	360		360	360		360	414		414	360		360
2018	360		360	360		360	416		416	360		360

TABLE D.8

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON & PER MMBTU

INEFFECTIVE OPEC CARTEL SCENARIO

YEAR	St. Johns River Power Park $/TON 1989$	St. Johns River Power Park $/TON NOMINAL	St. Johns River Power Park $/MMBTU 1989$	St. Johns River Power Park $/MMBTU NOMINAL	High Sulfur Coal to Martin $/TON 1989$	High Sulfur Coal to Martin $/TON NOMINAL	High Sulfur Coal to Martin $/MMBTU 1989$	High Sulfur Coal to Martin $/MMBTU NOMINAL
1989	42.92	42.92	1.72	1.72	43.83	43.83	1.69	1.69
1990	41.57	43.44	1.66	1.74	42.69	43.67	1.64	1.68
1991	40.10	43.79	1.60	1.75	41.61	43.38	1.60	1.67
1992	37.32	42.63	1.49	1.71	40.89	43.70	1.57	1.68
1993	36.46	43.48	1.46	1.74	40.81	44.78	1.57	1.72
1994	35.11	43.92	1.40	1.76	40.52	45.71	1.56	1.76
1995	34.13	44.87	1.37	1.79	40.64	47.17	1.56	1.81
1996	33.29	46.08	1.33	1.84	40.59	48.63	1.56	1.87
1997	30.78	44.91	1.23	1.80	40.50	50.07	1.56	1.93
1998	29.98	46.16	1.20	1.85	40.44	51.64	1.56	1.99
1999	29.34	47.70	1.17	1.91	40.37	53.41	1.55	2.05
2000	28.40	48.94	1.14	1.96	40.29	55.23	1.55	2.12
2001	27.93	50.63	1.12	2.03	40.26	57.17	1.55	2.20
2002	26.19	50.08	1.05	2.00	40.12	59.02	1.54	2.27
2003	25.64	51.64	1.03	2.07	40.41	61.77	1.55	2.38
2004	25.41	53.88	1.02	2.16	40.40	64.16	1.55	2.47
2005	25.04	55.92	1.00	2.24	40.64	67.07	1.56	2.58
2006	24.70	58.01	0.99	2.32	41.10	70.47	1.58	2.71
2007	23.64	58.41	0.95	2.34	41.37	73.90	1.59	2.84
2008	23.46	61.00	0.94	2.44	41.62	77.48	1.60	2.98
2009	23.32	63.79	0.93	2.55	41.83	81.14	1.61	3.12
2010	23.17	66.67	0.93	2.67	42.46	85.81	1.63	3.30
2011	23.06	69.80	0.92	2.79	42.64	89.80	1.64	3.45
2012	22.45	71.50	0.90	2.86	43.03	94.78	1.65	3.65
2013	22.44	75.17	0.90	3.01	43.40	100.00	1.67	3.85
2014	22.45	79.11	0.90	3.16	43.76	105.46	1.68	4.06
2015	22.45	83.24	0.90	3.33	44.31	111.70	1.70	4.30
2016	21.50	83.87	0.86	3.35	44.64	117.72	1.72	4.53
2017	22.25	91.30	0.89	3.65	45.16	124.56	1.74	4.79
2018	22.28	96.15	0.89	3.85	45.54	131.39	1.75	5.05

MOST LIKELY SCENARIO

YEAR	St. Johns River Power Park $/TON 1989$	St. Johns River Power Park $/TON NOMINAL	St. Johns River Power Park $/MMBTU 1989$	St. Johns River Power Park $/MMBTU NOMINAL	High Sulfur Coal to Martin $/TON 1989$	High Sulfur Coal to Martin $/TON NOMINAL	High Sulfur Coal to Martin $/MMBTU 1989$	High Sulfur Coal to Martin $/MMBTU NOMINAL
1989	42.92	42.92	1.72	1.72	43.83	43.83	1.69	1.69
1990	42.46	44.38	1.70	1.78	42.98	44.91	1.65	1.73
1991	42.01	45.88	1.68	1.84	42.14	46.01	1.62	1.77
1992	39.90	45.58	1.60	1.82	41.69	47.62	1.60	1.83
1993	39.62	47.25	1.58	1.89	41.92	49.99	1.61	1.92
1994	38.93	48.70	1.56	1.95	42.07	52.63	1.62	2.02
1995	38.66	50.83	1.55	2.03	42.68	56.11	1.64	2.16
1996	38.47	53.26	1.54	2.13	43.29	59.93	1.66	2.30
1997	36.33	53.01	1.45	2.12	43.89	64.05	1.69	2.46
1998	36.15	55.64	1.45	2.23	44.50	68.50	1.71	2.63
1999	36.06	58.62	1.44	2.34	45.11	73.33	1.73	2.82
2000	35.71	61.36	1.43	2.45	45.71	78.55	1.76	3.02
2001	35.65	64.63	1.43	2.59	46.38	84.08	1.78	3.23
2002	34.04	65.11	1.36	2.60	46.84	89.58	1.80	3.45
2003	33.78	68.04	1.35	2.72	47.72	96.11	1.84	3.70
2004	33.92	71.94	1.36	2.88	48.26	102.35	1.86	3.94
2005	33.89	75.67	1.36	3.03	49.07	109.58	1.89	4.21
2006	33.84	79.49	1.35	3.18	50.15	117.81	1.93	4.53
2007	32.70	80.81	1.31	3.23	50.96	125.93	1.96	4.84
2008	32.77	85.19	1.31	3.41	51.77	134.58	1.99	5.18
2009	32.89	89.95	1.32	3.60	52.58	143.79	2.02	5.53
2010	32.99	94.91	1.32	3.80	53.92	155.15	2.07	5.97
2011	33.14	100.32	1.33	4.01	54.73	165.67	2.11	6.37
2012	32.46	103.36	1.30	4.13	55.81	177.72	2.15	6.84
2013	32.62	109.28	1.30	4.37	56.89	190.57	2.19	7.33
2014	32.82	115.67	1.31	4.63	57.97	204.28	2.23	7.86
2015	33.02	122.40	1.32	4.90	59.32	219.90	2.28	8.46
2016	31.80	124.04	1.27	4.96	60.39	235.54	2.32	9.06
2017	33.10	135.81	1.32	5.43	61.74	253.32	2.37	9.74
2018	33.33	143.84	1.33	5.75	62.92	271.57	2.42	10.45

EFFECTIVE OPEC CARTEL SCENARIO

YEAR	St. Johns River Power Park $/TON 1989$	St. Johns River Power Park $/TON NOMINAL	St. Johns River Power Park $/MMBTU 1989$	St. Johns River Power Park $/MMBTU NOMINAL	High Sulfur Coal to Martin $/TON 1989$	High Sulfur Coal to Martin $/TON NOMINAL	High Sulfur Coal to Martin $/MMBTU 1989$	High Sulfur Coal to Martin $/MMBTU NOMINAL
1989	42.92	42.92	1.72	1.72	44.51	44.51	1.71	1.71
1990	42.99	44.93	1.72	1.80	43.73	46.26	1.68	1.78
1991	43.22	47.20	1.73	1.89	42.89	48.20	1.65	1.85
1992	41.49	47.39	1.66	1.90	42.47	50.44	1.63	1.94
1993	41.67	49.69	1.67	1.99	42.98	53.90	1.65	2.07
1994	41.18	51.51	1.65	2.06	43.32	57.32	1.67	2.20
1995	41.05	53.96	1.64	2.16	44.23	61.74	1.70	2.37
1996	40.88	56.60	1.64	2.26	45.02	66.24	1.73	2.55
1997	38.61	56.33	1.54	2.25	45.0[illegible]	71.04	1.76	2.73
1998	38.38	59.08	1.54	2.36	46.56	76.11	1.79	2.93
1999	38.17	62.06	1.53	2.48	47.41	81.59	1.82	3.14
2000	37.66	64.71	1.51	2.59	48.34	87.60	1.86	3.37
2001	37.53	68.04	1.50	2.72	49.24	93.97	1.89	3.61
2002	35.77	68.41	1.43	2.74	50.00	100.47	1.92	3.86
2003	35.46	71.42	1.42	2.86	51.23	108.31	1.97	4.17
2004	35.58	75.45	1.42	3.02	52.02	115.68	2.00	4.45
2005	35.51	79.28	1.42	3.17	53.11	124.26	2.04	4.78
2006	35.45	83.78	1.42	3.33	54.47	134.06	2.10	5.16
2007	34.23	84.58	1.37	3.38	55.59	143.80	2.14	5.53
2008	34.27	89.09	1.37	3.56	56.71	154.17	2.18	5.93
2009	34.36	93.98	1.37	3.76	57.97	165.63	2.23	6.37
2010	34.43	99.06	1.38	3.96	59.66	179.16	2.29	6.89
2011	34.56	104.61	1.38	4.18	60.79	191.86	2.34	7.38
2012	33.81	107.67	1.35	4.31	62.35	206.84	2.40	7.96
2013	33.95	113.73	1.36	4.55	63.82	222.49	2.45	8.56
2014	34.13	120.27	1.37	4.81	65.31	239.32	2.51	9.20
2015	34.27	127.03	1.37	5.08	67.15	258.36	2.58	9.94
2016	32.94	128.48	1.32	5.14	68.72	277.62	2.64	10.68
2017	34.22	140.41	1.37	5.62	70.46	298.89	2.71	11.50
2018	34.39	148.42	1.38	5.94	71.72	319.41	2.76	12.28

TABLE D.9

1989 TO 2018 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1989 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON MAY 4, 1989
DELIVERED CONSTANT 1989 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU
AND COAL PRICES IN DOLLARS PER TON AND PER MMBTU

OIL SHOCK SCENARIO

	INTERRUPTIBLE NATURAL GAS $/MMBTU		FIRM NATURAL GAS $/MMBTU		AVERAGE NATURAL GAS $/MMBTU		ST. JOHNS RIVER POWER PARK $/TON		ST. JOHNS RIVER POWER PARK $/MMBTU		HIGH SULFUR COAL TO MARTIN $/TON		HIGH SULFUR COAL TO MARTIN $/MMBTU	
YEAR	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL	1989$	NOMINAL
1989	2.49	2.49	2.21	2.21	2.48	2.48	44.72	44.72	1.72	1.72	43.94	43.94	1.69	1.69
1990	2.40	2.57	2.54	2.72	2.51	2.69	44.20	47.31	1.70	1.82	42.90	45.92	1.65	1.77
1991	2.46	2.78	2.61	2.95	2.59	2.93	43.68	49.29	1.68	1.90	42.12	47.53	1.62	1.83
1992	2.72	3.24	2.81	3.35	2.80	3.34	41.60	49.52	1.60	1.90	41.60	49.52	1.60	1.90
1993	7.46	9.84	4.53	5.98	4.77	6.29	41.08	54.15	1.58	2.08	41.86	55.18	1.61	2.12
1994	7.12	9.88			7.12	9.88	40.56	56.23	1.56	2.16	42.12	58.39	1.62	2.25
1995	6.44	9.30			6.44	9.30	40.30	58.24	1.55	2.24	42.64	61.62	1.64	2.37
1996	6.17	9.36			6.17	9.36	40.04	60.74	1.54	2.34	43.16	65.47	1.66	2.52
1997	5.90	9.41			5.90	9.41	37.70	60.15	1.45	2.31	43.94	70.11	1.69	2.70
1998	5.56	9.33			5.56	9.33	37.70	63.20	1.45	2.43	44.46	74.54	1.71	2.87
1999	5.43	9.58			5.43	9.58	37.44	65.99	1.44	2.54	44.98	79.28	1.73	3.05
2000	1.64	2.92			1.64	2.92	37.18	66.27	1.43	2.55	45.76	81.56	1.76	3.14
2001	3.27	6.22			3.27	6.22	37.18	70.62	1.43	2.72	46.28	87.91	1.78	3.38
2002	4.71	9.52			4.71	9.52	35.36	71.44	1.36	2.75	46.80	94.56	1.80	3.64
2003	5.18	11.03			5.18	11.03	35.10	74.71	1.35	2.87	47.84	101.83	1.84	3.92
2004	5.28	11.85			5.28	11.85	35.36	79.33	1.36	3.05	48.36	108.49	1.86	4.17
2005	5.37	12.68			5.37	12.68	35.36	83.50	1.36	3.21	49.14	116.03	1.89	4.46
2006	5.46	13.58			5.46	13.58	35.10	87.29	1.35	3.36	50.18	124.79	1.93	4.80
2007	5.55	14.53			5.55	14.53	34.06	89.18	1.31	3.43	50.96	133.43	1.96	5.13
2008	5.65	15.59			5.65	15.59	34.06	93.99	1.31	3.62	51.74	142.78	1.99	5.49
2009	5.73	16.66			5.73	16.66	34.32	99.80	1.32	3.84	52.52	152.72	2.02	5.87
2010	5.83	17.86			5.83	17.86	34.32	105.16	1.32	4.04	53.82	164.92	2.07	6.34
2011	5.92	19.12			5.92	19.12	34.58	111.66	1.33	4.29	54.86	177.14	2.11	6.81
2012	6.02	20.49			6.02	20.49	33.80	115.02	1.30	4.42	55.90	190.22	2.15	7.32
2013	6.13	21.97			6.13	21.97	33.80	121.12	1.30	4.66	56.94	204.05	2.19	7.85
2014	6.24	23.55			6.24	23.55	34.06	128.52	1.31	4.94	57.98	218.77	2.23	8.41
2015	6.36	25.23			6.36	25.23	34.32	136.16	1.32	5.24	59.28	235.19	2.28	9.05
2016	6.49	27.06			6.49	27.06	33.02	137.67	1.27	5.30	60.32	251.49	2.32	9.67
2017	6.62	29.01			6.62	29.01	34.32	150.38	1.32	5.78	61.62	270.00	2.37	10.38
2018	6.76	31.10			6.76	31.10	34.58	159.07	1.33	6.12	62.92	289.44	2.42	11.13

Appendix E
Computer Programs

Computer Programs

PROMOD

The PROMOD and PROSCREEN programs (both developed by Energy Management Associates, Inc.) are the production cost simulators used throughout this study. PROMOD is a rigorous program which includes seasonal dispatch and is capable of modeling duel fuel generation and limited fuel contracts. It is used by FPL for all detailed production costing requirements. However, PROMOD runs in a batch mode and requires very detailed input and a great amount of computer time, making it impractical for optimization studies requiring a multitude of simulations with quick turn-around. Also, PROMOD calculates only production costs and has no capability to compute annual capital revenue requirements.

PROSCREEN

PROSCREEN is a less rigorous program used to cost various generation option plans. It has the capability for seasonal dispatch and it runs interactively, requiring a minimal amount of computer time and producing very fast results. This allows for the rapid evaluation of numerous scenarios and expansion plans. Furthermore, the PROSCREEN data base is developed through a direct translation of the same detailed PROMOD data base. The actual translation mechanism is an integral part of PROMOD and is triggered through a parameter option in the PROMOD input. PROSCREEN calculates the total annual revenue requirements, including the production costs and the capital revenue requirements.

TIGER

The reliability model used in this analysis was TIGER, the "Tie Line Assistance and Generation Reliability Program," developed by Florida Power Corporation. TIGER is a two area loss-of-load probability program that will calculate system percent reserve, loss-of-load probability (LOLP in days per month and days per year) and loss-of-load hours for a given area or utility under study. It will calculate the LOLP or LOLH for the primary area as a stand alone system and then if requested, calculate the Net LOLP considering tie line assistance available from neighboring utilities using the same time period. The "Net LOLP" is the LOLP of the combined area limited by the tie line capacity. In addition to generation, up to ten transactions (purchase/sale) may be modeled with availabilities changing each month, if necessary. If transactions are in effect, the tie lines can be derated by the transaction amounts. The program logic can be selected to calculate the LOLP from either cumulants or the convolution method and can accept multiple stages for each generator.

AVERAGE TOTAL CUSTOMERS*
HISTORY AND FORECAST

YEAR	CUSTOMERS	ANNUAL % CHANGE
1978	1,967,364	4.9
1979	2,074,340	5.4
1980	2,184,985	5.3
1981	2,285,202	4.6
1982	2,358,184	3.2
1983	2,429,705	3.0
1984	2,520,537	3.7
1985	2,617,556	3.8
1986	2,723,555	4.0
1987	2,840,214	4.3
1988	2,953,621	4.0

Compound Average Annual Growth Rate
1978 through 1988 4.1%

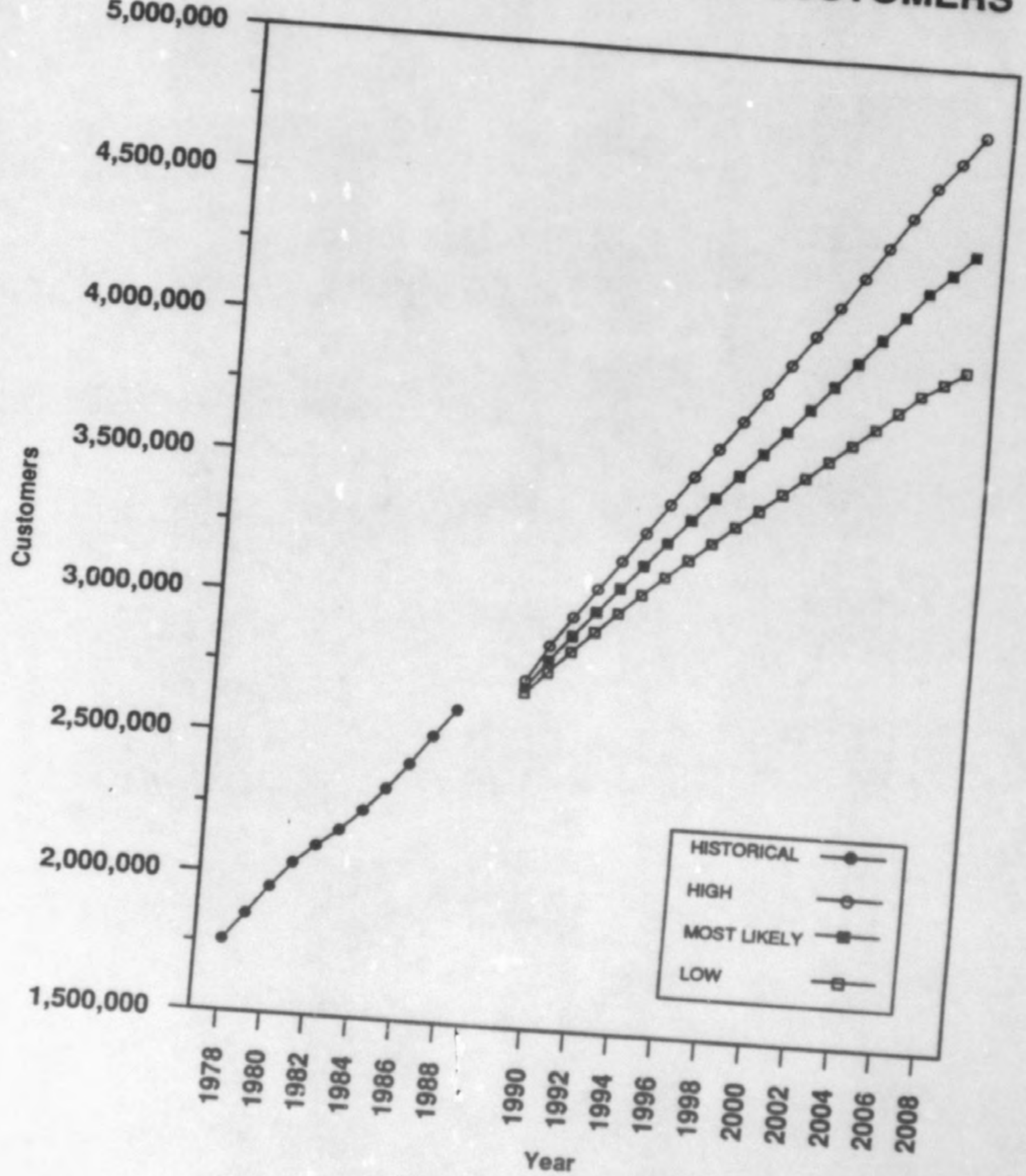
YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	3,044,518	3.1	3,067,305	3.8	3,094,646	4.8
1990	3,136,297	3.0	3,183,006	3.8	3,240,781	4.7
1991	3,226,001	2.9	3,291,241	3.4	3,367,146	3.9
1992	3,314,622	2.7	3,397,843	3.2	3,493,192	3.7
1993	3,400,548	2.6	3,503,206	3.1	3,619,058	3.6
1994	3,483,776	2.4	3,607,347	3.0	3,744,966	3.5
1995	3,564,394	2.3	3,710,098	2.8	3,870,598	3.4
1996	3,643,052	2.2	3,811,143	2.7	3,994,940	3.2
1997	3,719,703	2.1	3,910,782	2.6	4,119,160	3.1
1998	3,794,510	2.0	4,009,416	2.5	4,243,681	3.0
1999	3,868,298	1.9	4,108,041	2.5	4,369,401	3.0
2000	3,941,809	1.9	4,207,333	2.4	4,497,114	2.9
2001	4,016,119	1.9	4,307,716	2.4	4,625,802	2.9
2002	4,090,734	1.9	4,409,329	2.4	4,757,730	2.9
2003	4,165,271	1.8	4,511,938	2.3	4,891,217	2.8
2004	4,239,758	1.8	4,615,478	2.3	5,026,819	2.8
2005	4,314,139	1.8	4,719,931	2.3	5,164,584	2.7
2006	4,389,616	1.7	4,825,390	2.2	5,303,671	2.7
2007	4,446,842	1.3	4,911,909	1.8	5,423,462	2.3
2008	4,504,146	1.3	4,999,345	1.8	5,545,231	2.2

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.5%	3.1%	3.7%
1988-2008	2.1%	2.7%	3.2%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE RESIDENTIAL CUSTOMERS



AVERAGE RESIDENTIAL CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	1,758,838	81,306	4.9	89.4
1979	1,854,884	96,046	5.5	89.4
1980	1,955,240	100,356	5.4	89.5
1981	2,044,623	89,383	4.6	89.5
1982	2,110,357	65,734	3.2	89.5
1983	2,170,686	60,329	2.9	89.3
1984	2,246,834	76,148	3.5	89.1
1985	2,329,677	82,843	3.7	89.0
1986	2,419,769	90,092	3.9	88.8
1987	2,519,694	99,925	4.1	88.7
1988	2,618,046	98,352	3.9	88.6

Compound Average Annual Growth Rate
1978 through 1988 4.1%

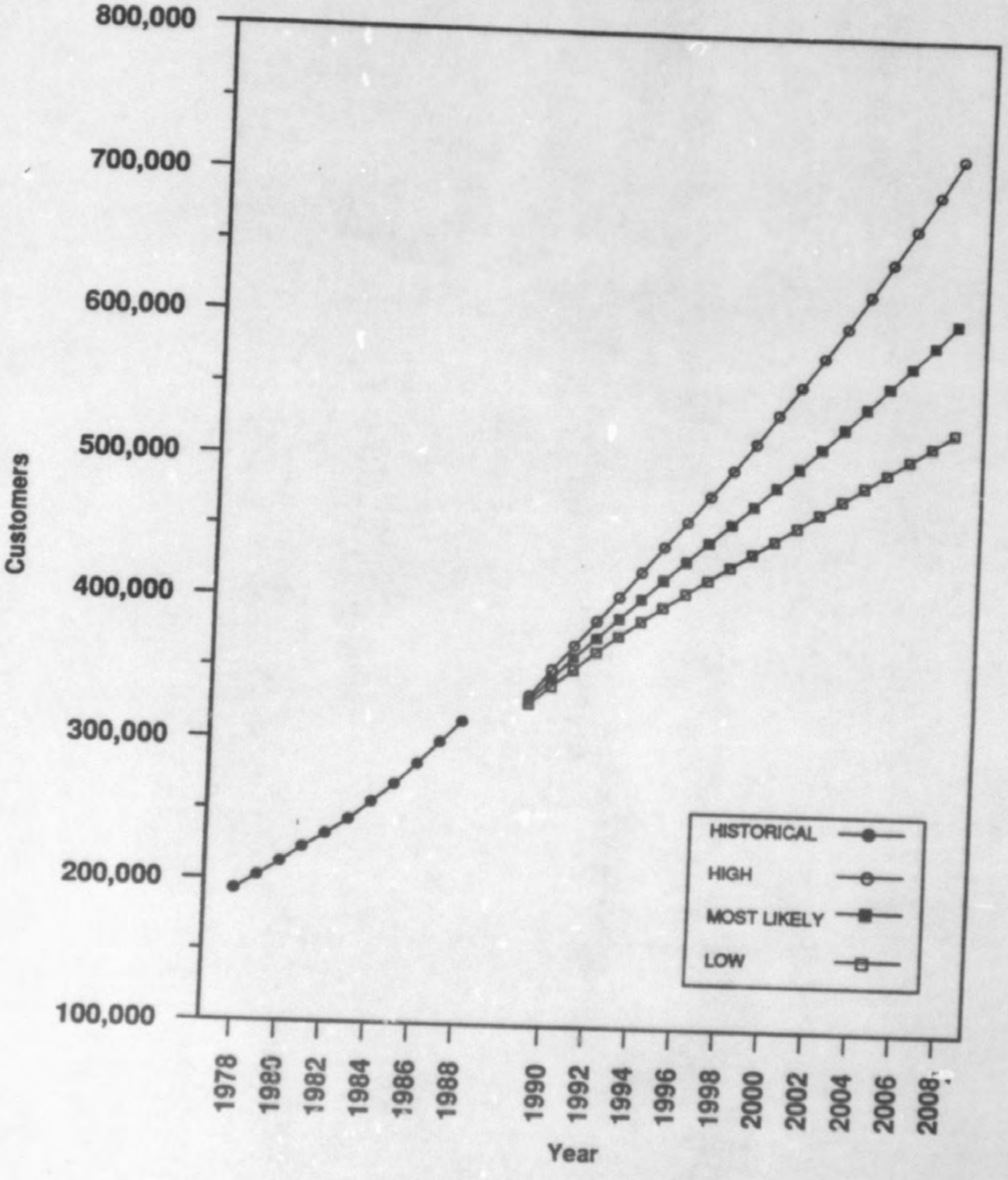
YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	2,695,062	2.9	2,715,008	3.7	2,739,607	4.6
1990	2,773,876	2.9	2,814,646	3.7	2,866,340	4.6
1991	2,850,884	2.8	2,906,754	3.3	2,973,682	3.7
1992	2,926,167	2.6	2,997,985	3.1	3,080,978	3.6
1993	2,999,773	2.5	3,088,400	3.0	3,188,316	3.5
1994	3,071,496	2.4	3,177,802	2.9	3,295,494	3.4
1995	3,141,234	2.3	3,266,057	2.8	3,402,326	3.2
1996	3,209,444	2.2	3,352,930	2.7	3,507,803	3.1
1997	3,275,627	2.1	3,438,390	2.5	3,612,617	3.0
1998	3,340,321	2.0	3,523,069	2.5	3,717,438	2.9
1999	3,403,870	1.9	3,607,295	2.4	3,822,439	2.8
2000	3,467,100	1.9	3,691,956	2.3	3,928,637	2.8
2001	3,530,818	1.8	3,777,535	2.3	4,036,112	2.7
2002	3,594,720	1.8	3,864,073	2.3	4,145,494	2.7
2003	3,658,650	1.8	3,951,437	2.3	4,256,358	2.7
2004	3,722,550	1.7	4,039,559	2.2	4,368,761	2.6
2005	3,786,331	1.7	4,128,352	2.2	4,482,617	2.6
2006	3,851,265	1.7	4,217,911	2.2	4,596,869	2.5
2007	3,898,024	1.2	4,288,275	1.7	4,690,876	2.0
2008	3,944,860	1.2	4,359,289	1.7	4,786,263	2.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.5%	3.0%	3.6%
1988-2008	2.1%	2.6%	3.1%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE COMMERCIAL CUSTOMERS



AVERAGE COMMERCIAL CUSTOMERS*
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	192,850	8,174	4.4	9.8
1979	202,673	9,823	5.1	9.8
1980	212,956	10,283	5.1	9.7
1981	223,399	10,443	4.9	9.8
1982	232,912	9,513	4.3	9.9
1983	243,269	10,357	4.4	10.0
1984	256,304	13,035	5.4	10.2
1985	268,780	12,476	4.9	10.3
1986	283,540	14,760	5.5	10.4
1987	299,634	16,094	5.7	10.5
1988	314,358	14,724	4.9	10.6

Compound Average Annual Growth Rate
1978 through 1988 5.0%

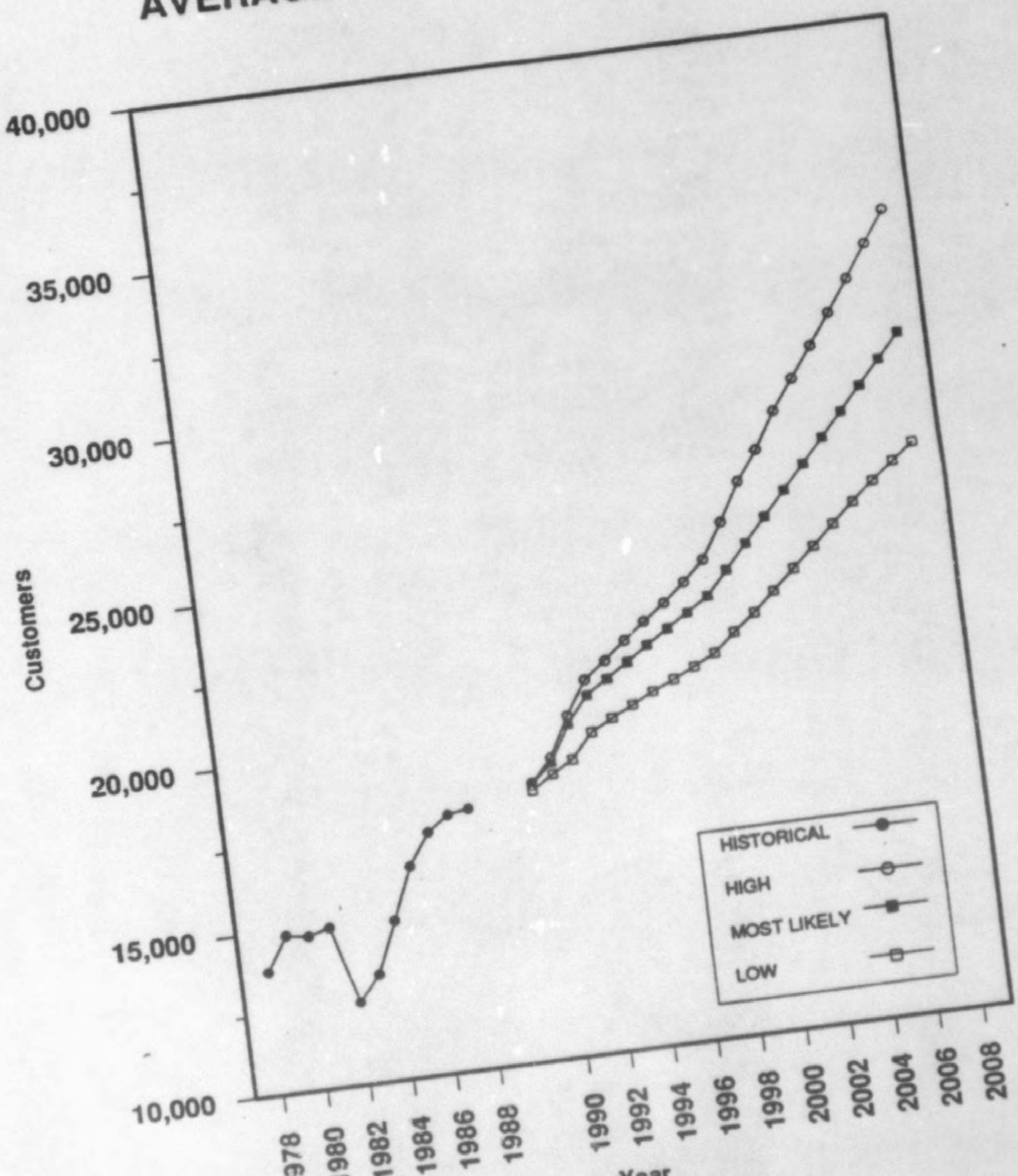
YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	327,791	4.3	330,409	5.1	333,054	5.9
1990	340,138	3.8	345,660	4.6	351,559	5.6
1991	352,269	3.6	360,499	4.3	369,156	5.0
1992	364,671	3.5	374,850	4.0	386,707	4.8
1993	376,454	3.2	389,171	3.8	404,486	4.6
1994	387,456	2.9	403,281	3.6	422,453	4.4
1995	397,831	2.7	417,150	3.4	440,505	4.3
1996	407,834	2.5	430,695	3.2	458,630	4.1
1997	417,821	2.4	444,247	3.1	477,235	4.1
1998	427,446	2.3	457,575	3.0	496,083	3.9
1999	436,989	2.2	471,050	2.9	515,501	3.9
2000	446,605	2.2	484,786	2.9	535,662	3.9
2001	456,479	2.2	498,702	2.9	555,777	3.8
2002	466,451	2.2	512,889	2.8	577,014	3.8
2003	476,343	2.1	527,245	2.8	598,501	3.7
2004	486,209	2.1	541,775	2.8	620,580	3.7
2005	496,094	2.0	556,547	2.7	643,369	3.7
2006	505,950	2.0	571,558	2.7	667,061	3.7
2007	515,766	1.9	586,824	2.7	691,646	3.7
2008	525,611	1.9	602,357	2.6	716,852	3.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	3.1%	3.8%	4.7%
1988-2008	2.6%	3.3%	4.2%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE INDUSTRIAL CUSTOMERS



AVERAGE INDUSTRIAL CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	13,799	2,003	17.0	0.7
1979	14,837	1,038	7.5	0.7
1980	14,734	(103)	-0.7	0.7
1981	14,923	189	1.3	0.7
1982	12,530	(2,393)	-16.0	0.5
1983	13,333	803	6.4	0.5
1984	14,892	1,559	11.7	0.6
1985	16,426	1,534	10.3	0.6
1986	17,373	947	5.8	0.6
1987	17,824	451	2.6	0.6
1988	17,923	99	0.6	0.6

Compound Average Annual Growth Rate
1978 through 1988 2.6%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	18,208	1.6	18,375	2.5	18,434	2.9
1990	18,626	2.3	18,985	3.3	19,126	3.8
1991	18,992	2.0	20,072	5.7	20,350	6.4
1992	19,731	3.9	20,891	4.1	21,344	4.9
1993	20,092	1.8	21,308	2.0	21,848	2.4
1994	20,423	1.6	21,725	2.0	22,365	2.4
1995	20,756	1.6	22,143	1.9	22,864	2.2
1996	21,031	1.3	22,560	1.9	23,355	2.1
1997	21,340	1.5	22,978	1.9	23,904	2.4
1998	21,661	1.5	23,395	1.8	24,501	2.5
1999	22,189	2.4	24,109	3.1	25,547	4.3
2000	22,711	2.4	24,823	3.0	26,680	4.4
2001	23,293	2.6	25,537	2.9	27,562	3.3
2002	23,896	2.6	26,251	2.8	28,656	4.0
2003	24,476	2.4	26,965	2.7	29,575	3.2
2004	25,061	2.4	27,680	2.6	30,478	3.1
2005	25,642	2.3	28,394	2.6	31,380	3.0
2006	26,195	2.2	29,108	2.5	32,303	2.9
2007	26,712	2.0	29,822	2.5	33,281	3.0
2008	27,201	1.8	30,536	2.4	34,235	2.9

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.9%	2.7%	3.2%
1988-2008	2.1%	2.7%	3.3%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE STREET & HIGHWAY CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	1,491			0.1
1979	1,553	53	3.7	0.1
1980	1,657	62	4.2	0.1
1981	1,843	104	6.7	0.1
1982	1,970	186	11.2	0.1
1983	2,021	127	6.9	0.1
1984	2,109	51	2.6	0.1
1985	2,286	88	4.4	0.1
1986	2,495	177	8.4	0.1
1987	2,687	209	9.1	0.1
1988	2,929	192	7.7	0.1
		242	9.0	

Compound Average Annual Growth Rate 1978 through 1988 7.0%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	3,102	5.9	3,150	7.5	3,181	8.6
1990	3,306	6.6	3,357	6.6	3,390	6.6
1991	3,508	6.1	3,562	6.1	3,597	6.1
1992	3,710	5.8	3,767	5.8	3,804	5.8
1993	3,889	4.8	3,980	5.7	4,052	6.5
1994	4,066	4.6	4,193	5.4	4,302	6.2
1995	4,242	4.3	4,406	5.1	4,553	5.8
1996	4,416	4.1	4,620	4.8	4,807	5.6
1997	4,589	3.9	4,833	4.6	5,062	5.3
1998	4,761	3.7	5,046	4.4	5,318	5.1
1999	4,932	3.6	5,259	4.2	5,577	4.9
2000	5,078	3.0	5,442	3.5	5,800	4.0
2001	5,219	2.8	5,619	3.3	6,017	3.8
2002	5,359	2.7	5,797	3.2	6,236	3.6
2003	5,498	2.6	5,974	3.1	6,456	3.5
2004	5,637	2.5	6,152	3.0	6,676	3.4
2005	5,776	2.5	6,329	2.9	6,898	3.3
2006	5,913	2.4	6,507	2.8	7,120	3.2
2007	6,050	2.3	6,684	2.7	7,343	3.1
2008	6,187	2.3	6,862	2.7	7,568	3.1

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	5.0%	5.6%	6.1%
1988-2008	3.8%	4.3%	4.9%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE OTHER CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	343	4	1.2	***
1979	350	7	2.0	***
1980	354	4	1.1	***
1981	369	15	4.2	***
1982	369	0	0.0	***
1983	346	-23	-6.2	***
1984	354	8	2.3	***
1985	343	-11	-3.1	***
1986	338	-5	-1.5	***
1987	337	-1	-0.3	***
1988	330	-7	-2.1	***

Compound Average Annual Growth Rate
1978 through 1988
-0.4%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	323	-2.2	328	-0.7	333	0.8
1990	319	-1.0	324	-1.0	329	-1.0
1991	316	-1.0	321	-1.0	326	-1.0
1992	313	-1.0	318	-1.0	323	-1.0
1993	310	-1.2	315	-1.0	320	-0.9
1994	306	-1.1	312	-1.0	317	-0.8
1995	302	-1.1	308	-1.0	314	-0.8
1996	299	-1.1	305	-1.0	312	-0.9
1997	296	-1.2	302	-1.0	309	-0.9
1998	292	-1.2	299	-1.0	307	-0.9
1999	289	-1.1	296	-1.0	304	-0.8
2000	285	-1.2	293	-1.0	301	-0.9
2001	282	-1.1	290	-1.0	299	-0.9
2002	279	-1.1	287	-1.0	296	-0.9
2003	276	-1.2	285	-1.0	294	-0.8
2004	273	-1.1	282	-1.0	291	-0.9
2005	269	-1.2	279	-1.0	289	-0.9
2006	266	-1.2	276	-1.0	286	-0.9
2007	263	-1.1	273	-1.0	284	-0.8
2008	260	-1.2	271	-1.0	281	-0.8

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-1.2%	-1.0%	-0.7%
1988-2008	-1.2%	-1.0%	-0.8%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE RAILROADS & RAILWAYS CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1984	7	7	--	***
1985	19	12	171.4	***
1986	22	3	15.8	***
1987	22	0	0.0	***
1988	22	0	0.0	***

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	20	9.1	22	0.0	23	4.5
1990	20	0.0	22	0.0	23	0.0
1991	20	0.0	22	0.0	23	0.0
1992	20	0.0	22	0.0	23	0.0
1993	20	0.0	22	0.0	23	0.0
1994	20	0.0	22	0.0	23	0.0
1995	20	0.0	22	0.0	23	0.0
1996	20	0.0	22	0.0	23	0.0
1997	20	0.0	22	0.0	23	0.0
1998	20	0.0	22	0.0	23	0.0
1999	20	0.0	22	0.0	23	0.0
2000	20	0.0	22	0.0	23	0.0
2001	20	0.0	22	0.0	23	0.0
2002	20	0.0	22	0.0	23	0.0
2003	20	0.0	22	0.0	23	0.0
2004	20	0.0	22	0.0	23	0.0
2005	20	0.0	22	0.0	23	0.0
2006	20	0.0	22	0.0	23	0.0
2007	20	0.0	22	0.0	23	0.0
2008	20	0.0	22	0.0	23	0.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-0.9%	0.0%	0.4%
1988-2008	-0.5%	0.0%	0.2%

* "Average Customers" is the annual average of the twelve-months' values.

AVERAGE RESALE CUSTOMERS *
HISTORY AND FORECAST

YEAR	CUSTOMERS	ABSOLUTE CHANGE	ANNUAL % CHANGE	% SYSTEM TOTAL
1978	43	-1	-2.3	***
1979	43	0	0.0	***
1980	44	1	2.3	***
1981	45	1	2.3	***
1982	46	1	2.2	***
1983	50	4	8.7	***
1984	37	-13	-26.0	***
1985	25	-12	-32.4	***
1986	19	-6	-24.0	***
1987	14	-5	-26.3	***
1988	14	0	0.0	***

Compound Average Annual Growth Rate
1978 through 1988 -10.6%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	12	-14.3	13	-7.1	14	0.0
1990	11	-8.3	12	-7.7	13	-7.7
1991	10	-9.1	11	-8.3	12	-7.7
1992	10	0.0	11	0.0	12	0.0
1993	10	0.0	11	0.0	12	0.0
1994	10	0.0	11	0.0	12	0.0
1995	10	0.0	11	0.0	12	0.0
1996	9	-10.0	10	-9.1	11	-8.3
1997	9	0.0	10	0.0	11	0.0
1998	9	0.0	10	0.0	11	0.0
1999	9	0.0	10	0.0	11	0.0
2000	9	0.0	10	0.0	11	0.0
2001	9	0.0	10	0.0	11	0.0
2002	8	-11.1	9	-10.0	10	-9.1
2003	8	0.0	9	0.0	10	0.0
2004	8	0.0	9	0.0	10	0.0
2005	7	-12.5	8	-11.1	9	-10.0
2006	7	0.0	8	0.0	9	0.0
2007	7	0.0	8	0.0	9	0.0
2008	7	0.0	8	0.0	9	0.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	-4.3%	-3.3%	-2.4%
1988-2008	-3.4%	-2.8%	-2.2%

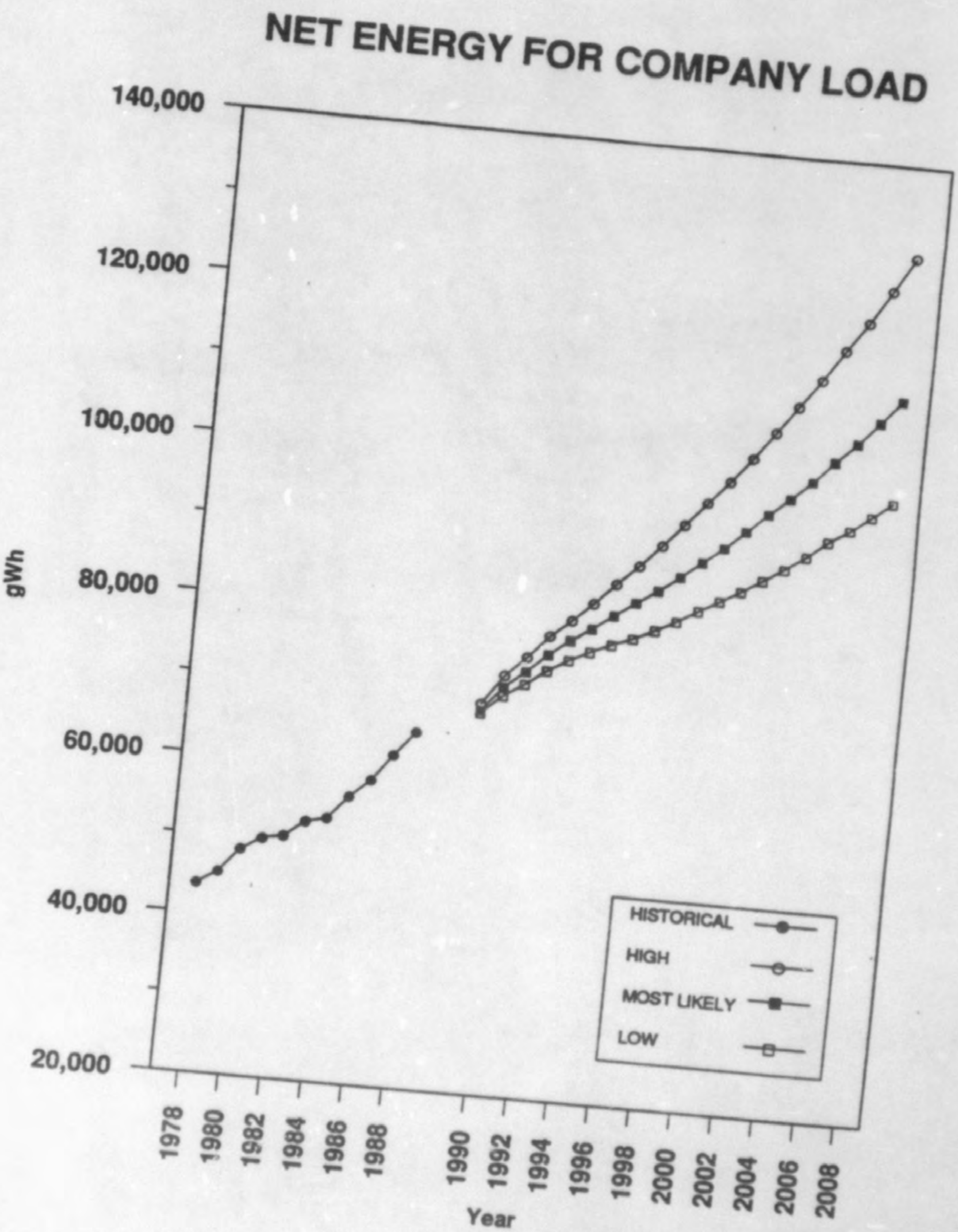
* "Average Customers" is the annual average of the twelve-months' values.

NET ENERGY FOR LOAD FORECAST

- 1978-1988 Net Energy For Company Load

  Net Energy For Load (NEL) Equals Our System's Net Generation Plus The Algebraic Sum Of Energy Transactions Between Utilities

- 1989-2008 Net Energy For Company Load



NET ENERGY FOR COMPANY LOAD
140,000
120,000
100,000
80,000
60,000
40,000
20,000
gWh
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
Year
HISTORICAL
HIGH
MOST LIKELY
LOW

NET ENERGY FOR COMPANY LOAD
HISTORY AND FORECAST

YEAR	ACTUAL GWH	ANNUAL % CHANGE
1978	43,706	7.4
1979	45,342	3.7
1980	48,450	6.9
1981	50,023	3.2
1982	50,532	1.0
1983	52,500	3.9
1984	53,149	1.2
1985	55,998	5.4
1986	58,266	4.1
1987	61,616	5.7
1988	64,716	5.0

Compound Average Annual Growth Rate
1978 through 1988 4.0%

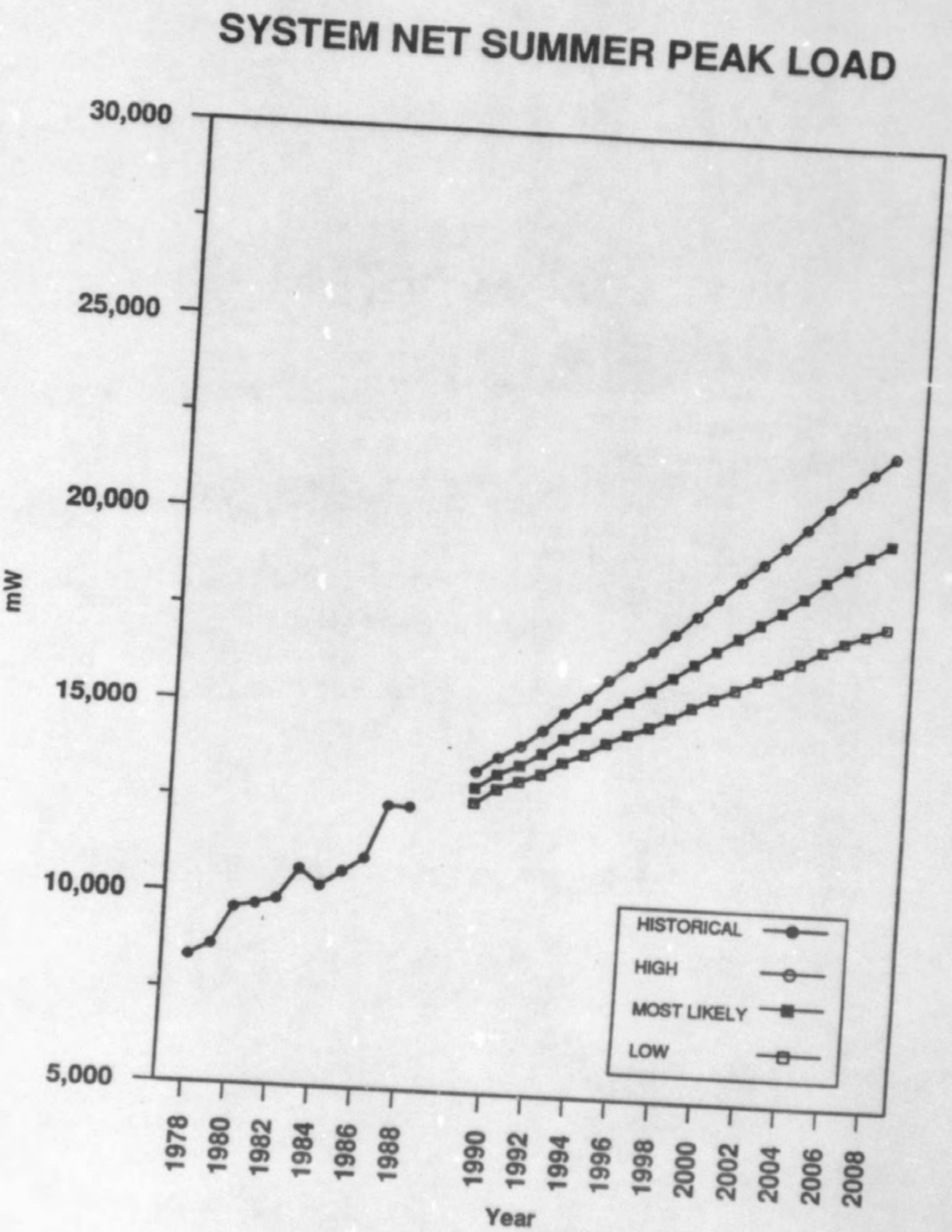
YEAR	LOW GWH	ANNUAL % CHANGE	MOST LIKELY GWH	ANNUAL % CHANGE	HIGH GWH	ANNUAL % CHANGE
1989	67,794	4.8	68,101	5.2	68,958	6.6
1990	70,104	3.4	71,259	4.6	72,663	5.4
1991	71,802	2.4	73,370	3.0	75,183	3.5
1992	73,686	2.6	75,731	3.2	78,007	3.8
1993	75,232	2.1	77,676	2.6	80,168	2.8
1994	76,486	1.7	79,380	2.2	82,527	2.9
1995	77,613	1.5	81,246	2.4	85,220	3.3
1996	78,598	1.3	83,068	2.2	87,687	2.9
1997	79,846	1.6	84,808	2.1	90,449	3.1
1998	81,155	1.6	86,727	2.3	93,338	3.2
1999	82,695	1.9	88,814	2.4	96,398	3.3
2000	84,109	1.7	90,791	2.2	99,310	3.0
2001	85,586	1.8	93,144	2.6	102,441	3.2
2002	87,186	1.9	95,545	2.6	105,909	3.4
2003	88,802	1.9	97,746	2.3	109,287	3.2
2004	90,572	2.0	100,177	2.5	112,809	3.2
2005	92,644	2.3	102,881	2.7	116,723	3.5
2006	94,280	1.8	105,396	2.4	120,333	3.1
2007	96,251	2.1	108,190	2.7	124,532	3.5
2008	98,262	2.1	111,040	2.6	128,806	3.4

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.3%	3.0%	3.7%
1988-2008	2.1%	2.7%	3.5%

PEAK LOAD FORECAST

- System Net Summer And Winter Peak Loads (Historical And Forecast)
- Time And Temperature Data For Summer And Winter Peak Loads (1978-1989)
- Impact Of Severe Weather On Peak (1989-2008)
- Divisional Load At Time Of System Summer Peak (Historical And Forecast)
- Forecast Of Program Impacts On Summer And Winter Peak Loads


SYSTEM NET SUMMER PEAK LOAD
30,000
25,000
20,000
15,000
10,000
5,000
mW
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
Year
HISTORICAL
HIGH
MOST LIKELY
LOW

SYSTEM NET SUMMER PEAK LOAD
HISTORY AND FORECAST
(60 Minute Net Including Qualifying Facilities)

YEAR	PEAK (MW)	ANNUAL % CHANGE
1978	8,345	6.4
1979	8,650	3.7
1980	9,623	11.2
1981	9,738	1.2
1982	9,893	1.6
1983	10,676	7.9
1984	10,270	-3.8
1985	10,654	3.7
1986	11,022	3.5
1987	12,394	12.4
1988	12,382	-0.1

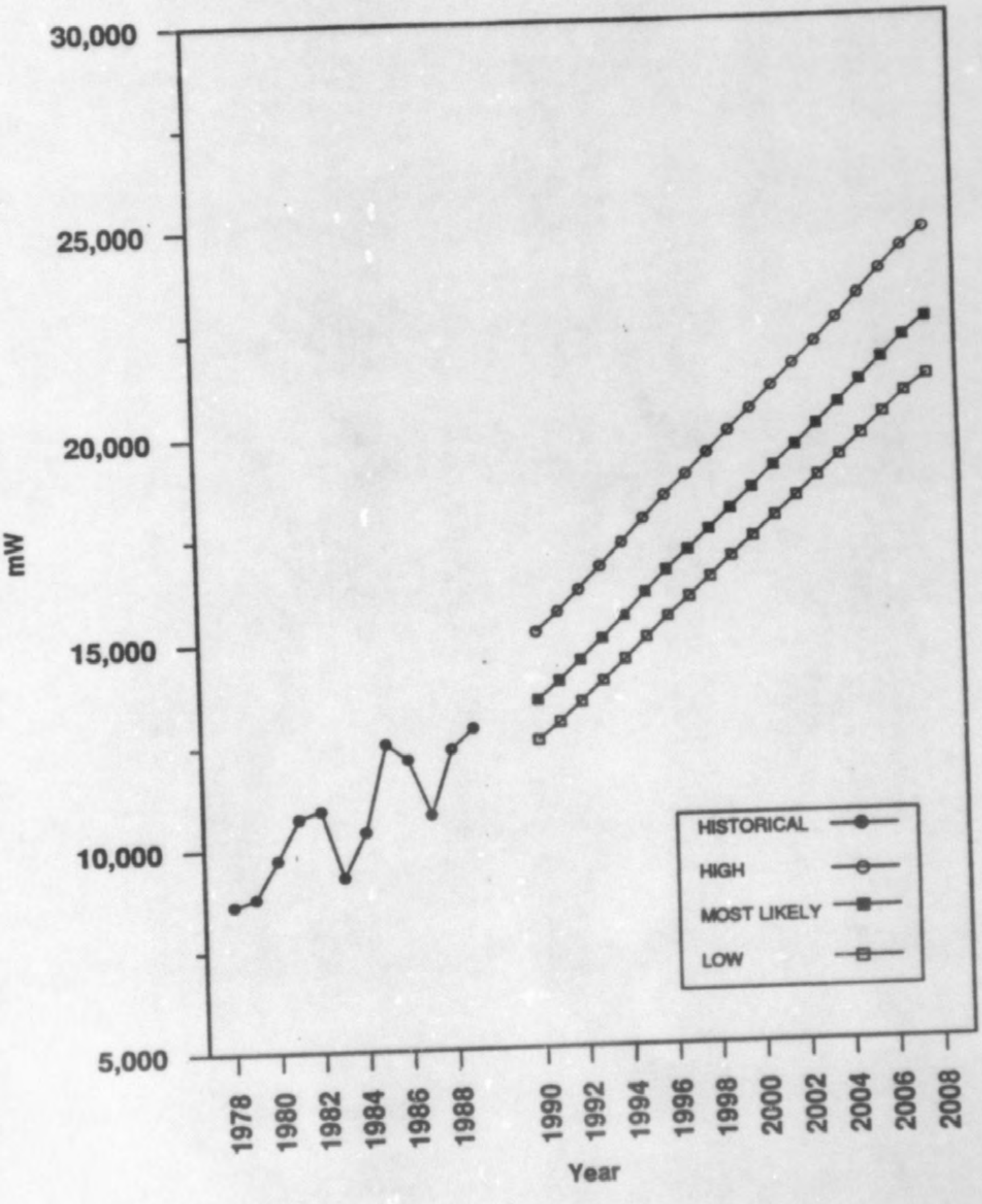
Compound Average Annual Growth Rate
1978 through 1988 4.0%

YEAR	LOW PEAK MW	ANNUAL % CHANGE	MOST LIKELY PEAK MW	ANNUAL % CHANGE	HIGH PEAK MW	ANNUAL % CHANGE
1989	12,564	1.5	12,962	4.7	13,387	8.1
1990	12,953	3.1	13,341	2.9	13,787	3.0
1991	13,170	1.7	13,613	2.0	14,116	2.4
1992	13,400	1.7	13,942	2.4	14,547	3.1
1993	13,730	2.5	14,355	3.0	15,046	3.4
1994	13,973	1.8	14,681	2.3	15,457	2.7
1995	14,294	2.3	15,092	2.8	15,961	3.3
1996	14,537	1.7	15,421	2.2	16,379	2.6
1997	14,761	1.5	15,732	2.0	16,780	2.4
1998	15,038	1.9	16,104	2.4	17,249	2.8
1999	15,334	2.0	16,499	2.5	17,746	2.9
2000	15,604	1.8	16,870	2.2	18,221	2.7
2001	15,864	1.7	17,232	2.1	18,688	2.6
2002	16,135	1.7	17,609	2.2	19,174	2.6
2003	16,371	1.5	17,951	1.9	19,625	2.4
2004	16,649	1.7	18,342	2.2	20,132	2.6
2005	16,977	2.0	18,793	2.5	20,709	2.9
2006	17,240	1.5	19,169	2.0	21,201	2.4
2007	17,454	1.2	19,493	1.7	21,638	2.1
2008	17,664	1.2	19,815	1.7	22,076	2.0

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	2.0%	2.7%	3.4%
1988-2008	1.8%	2.4%	2.9%

SYSTEM NET WINTER PEAK LOAD



SYSTEM NET WINTER PEAK LOAD
HISTORY AND FORECAST
(60 Minute Net Including Qualifying Facilities)

YEAR	MW	ANNUAL % CHANGE
1978-79	8,791	2.0
1979-80	9,732	10.7
1980-81	10,738*	10.3
1981-82	10,919**	1.7
1982-83	9,280	-15.0
1983-84	10,384***	11.9
1984-85	12,533	20.7
1985-86	12,139	-3.1
1986-87	10,779	-11.2
1987-88	12,372	14.8
1988-89	12,876	4.1

Compound Average Annual Growth Rate
1978-79 through 1988-1989 3.9%

YEAR	LOW PEAK MW	ANNUAL % CHANGE	MOST LIKELY PEAK MW	ANNUAL % CHANGE	HIGH PEAK MW	ANNUAL % CHANGE
1989-90	12,551	-2.5	13,518	5.0	15,176	17.9
1990-91	12,983	3.4	13,970	3.3	15,650	3.1
1991-92	13,454	3.6	14,463	3.5	16,169	3.3
1992-93	13,946	3.7	14,979	3.6	16,712	3.4
1993-94	14,456	3.7	15,513	3.6	17,275	3.4
1994-95	14,980	3.6	16,062	3.5	17,853	3.3
1995-96	15,475	3.3	16,583	3.2	18,405	3.1
1996-97	15,931	2.9	17,061	2.9	18,909	2.7
1997-98	16,399	2.9	17,551	2.9	19,426	2.7
1998-99	16,876	2.9	18,051	2.8	19,953	2.7
1999-00	17,353	2.8	18,552	2.8	20,480	2.6
2000-01	17,849	2.9	19,072	2.8	21,030	2.7
2001-02	18,320	2.6	19,566	2.6	21,551	2.5
2002-03	18,799	2.6	20,069	2.6	22,082	2.5
2003-04	19,293	2.6	20,587	2.6	22,628	2.5
2004-05	19,798	2.6	21,117	2.6	23,187	2.5
2005-06	20,312	2.6	21,656	2.6	23,757	2.5
2006-07	20,809	2.4	22,178	2.4	24,308	2.3
2007-08	21,204	1.9	22,593	1.9	24,757	1.8

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-89 through 1998-99	2.7%	3.4%	4.5%
1988-89 through 2007-08	2.7%	3.0%	3.5%

* Unserved Load of 567 mW
** Unserved Load of 426 mW
*** Unserved Load of 666 mW

TIME AND TEMPERATURE DATA FOR

SUMMER PEAK LOAD

60 MINUTE NET

Year	Peaks: Date of Peak	Time of Peak	Peak mW	Peak Per Customer (kW)	Average Temperature on Day of Peak: Miami (°F)
1970	9/10	5-6 P	5,001*	3.974	86
1971	8/25	5-6 P	5,378**	3.957	84
1972	7/27	5-6 P	6,011	4.212	84
1973	9/10	5-6 P	6,894	4.388	83
1974	9/12	5-6 P	7,235	4.312	86
1975	8/25	5-6 P	7,076	4.116	83
1976	7/15	5-6 P	7,598	4.285	85
1977	7/11	5-6 P	7,841	4.236	85
1978	8/29	5-6 P	8,345	4.258	85
1979	7/19	5-6 P	8,650	4.215	83
1980	7/14	5-6 P	9,623	4.428	86
1981	7/15	4-5 P	9,738	4.290	87
1982	8/24	5-6 P	9,893	4.228	87
1983	7/25	5-6 P	10,676	4.435	92
1984	8/09	4-5 P	10,270	4.098	90
1985	6/03	5-6 P	10,654	4.109	85
1986	8/26	4-5 P	11,022	4.064	83
1987	8/07	4-5 P	12,394	4.381	88
1988	8/03	5-6 P	12,382	4.209	86

* Unserved load of 30 mW.
** Unserved load of 118 mW.

TIME AND TEMPERATURE DATA FOR

WINTER PEAK LOAD

60 MINUTE NET

	Peaks				Average Temperature on Day of Peak
Year	Date of Peak	Time of Peak	Peak mW	Peak Per Customer (kW)	Miami (°F)
1970	1/9	6-7 P	4,716	3.822	47
1971	1/20	7-8 P	5,059	3.844	45
1972	2/21	8-9 A	4,676*	3.270	57
1973	2/11	9-10 A	5,853	3.781	51
1974	2/27	8-9 A	6,258	3.754	57
1975	12/22	6-7 A	6,810	3.843	49
1976	1/19	8-9 A	7,287	4.073	55
1977	1/19	7-8 P	8,606**	4.620	44
1978	2/23	7-8 A	8,617	4.401	51
1979	2/2	7-8 A	8,791	4.257	53
1980	3/3	8-9 A	9,732	4.451	43
1981	1/13	9-10 A	10,738***	4.738	47
1982	1/12	7-8 A	10,919****	4.643	49
1983	12/26	9-10 A	10,384*****	4.175	42
1984	2/7	7-8 A	9,953	3.955	57
1985	1/22	8-9 A	12,533	4.823	42
1986	1/28	7-8 A	12,139	4.494	45
1987	1/28	7-8 A	10,779	3.830	56
1988	1/28	7-8 A	12,372	4.225	56
1989	2/25	8-9 A	12,876	4.213	50

* The system peak for the winter months of calendar year 1972 occurred on a date with unseasonably warm weather. The peak given above is the "cold weather" peak experienced by the system for that year. The absolute system peak and associated data observed during the winter months for 1972 are given below.

Year	Date of Peak	Time of Peak	Peak mW	Peak Per Customer (kW)	Miami (°F)
1972	12/14	6-7 P	5,371	3.548	77

** Unserved load of 117 mW.
*** Unserved load of 567 mW.
**** Unserved load of 426 mW.
***** Unserved load of 666 mW.

IMPACT OF EXTREME WEATHER ON SUMMER PEAKS*
TWENTY YEAR FORECAST
(Megawatts - 60 Minute Net)

Year	Summer
1989	13,418
1990	13,869
1991	14,341
1992	14,771
1993	15,257
1994	15,652
1995	16,118
1996	16,581
1997	16,994
1998	17,459
1999	17,942
2000	18,410
2001	18,887
2002	19,377
2003	19,831
2004	20,328
2005	20,885
2006	21,380
2007	21,814
2008	22,248

* Summer extreme weather combines the most likely economic scenario with the 90th percentile temperature for July-August potential peak hours during the last 25 years, plus the high band residential customer forecast.

DIVISION LOAD AT TIME OF SYSTEM SUMMER PEAK
HISTORY AND FORECAST
SOUTHERN DIVISION
(60 Minute Net)

YEAR	PEAK (MW)	ANNUAL % CHANGE	% SYSTEM TOTAL PEAK
1978	2,763	5.2	33.1
1979	2,847	3.0	32.9
1980	3,003	5.5	31.2
1981	3,062	2.0	31.4
1982	2,962	-3.3	30.0
1983	3,204	8.2	30.0
1984	2,990	-6.7	29.1
1985	3,406	13.9	32.0
1986	3,316	-2.6	30.1
1987	3,654	10.2	29.5
1988	3,375	-7.6	27.3

Compound Average Annual Growth Rate
1978 through 1988 2.0%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	3,564	5.6	3,677	8.9	3,798	12.5
1990	3,624	1.7	3,732	1.5	3,857	1.6
1991	3,649	0.7	3,771	1.0	3,909	1.4
1992	3,683	0.9	3,831	1.6	3,998	2.3
1993	3,720	1.0	3,889	1.5	4,076	2.0
1994	3,757	1.0	3,947	1.5	4,156	2.0
1995	3,819	1.7	4,032	2.2	4,264	2.6
1996	3,858	1.0	4,093	1.5	4,347	1.9
1997	3,898	1.0	4,154	1.5	4,431	1.9
1998	3,959	1.6	4,239	2.1	4,541	2.5
1999	4,013	1.4	4,318	1.9	4,644	2.3
2000	4,063	1.3	4,393	1.8	4,745	2.2
2001	4,111	1.2	4,466	1.7	4,843	2.1
2002	4,153	1.0	4,533	1.5	4,935	1.9
2003	4,196	1.0	4,601	1.5	5,030	1.9
2004	4,243	1.1	4,674	1.6	5,130	2.0
2005	4,294	1.2	4,754	1.7	5,238	2.1
2006	4,344	1.2	4,830	1.6	5,342	2.0
2007	4 385	1.0	4,897	1.4	5,436	1.8
2008	4,420	0.8	4,959	1.2	5,524	1.6

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.6%	2.3%	3.0%
1988-2008	1.4%	1.9%	2.5%

DIVISION LOAD AT TIME OF SYSTEM SUMMER PEAK
HISTORY AND FORECAST
SOUTHEASTERN DIVISION
(60 Minute Net)

YEAR	PEAK (MW)	ANNUAL % CHANGE	% SYSTEM TOTAL PEAK
1978	1,827		21.9
1979	1,867	2.2	21.6
1980	2,097	12.3	21.8
1981	2,043	-2.6	21.0
1982	2,098	2.7	21.3
1983	2,167	3.3	20.3
1984	2,091	-3.5	20.4
1985	1,855	-11.3	17.4
1986	2,129	14.8	19.3
1987	2,304	8.2	18.6
1988	2,607	13.2	21.1

Compound Average Annual Growth Rate
1978 through 1988 3.6%

YEAR	LOW	ANNUAL % CHANGE	MOST LIKELY	ANNUAL % CHANGE	HIGH	ANNUAL % CHANGE
1989	2,403	-7.8	2,495	-4.3	2,577	-1.2
1990	2,514	4.6	2,589	3.8	2,675	3.8
1991	2,557	1.7	2,643	2.1	2,741	2.5
1992	2,568	0.4	2,672	1.1	2,787	1.7
1993	2,700	5.2	2,823	5.7	2,959	6.2
1994	2,762	2.3	2,902	2.8	3,055	3.2
1995	2,870	3.9	3,030	4.4	3,204	4.9
1996	2,966	3.4	3,146	3.8	3,342	4.3
1997	3,031	2.2	3,230	2.7	3,445	3.1
1998	3,116	2.8	3,337	3.3	3,574	3.7
1999	3,209	3.0	3,452	3.5	3,713	3.9
2000	3,304	3.0	3,572	3.5	3,858	3.9
2001	3,389	2.6	3,681	3.1	3,992	3.5
2002	3,479	2.6	3,796	3.1	4,134	3.5
2003	3,555	2.2	3,898	2.7	4,262	3.1
2004	3,622	1.9	3,991	2.4	4,380	2.8
2005	3,742	3.3	4,142	3.8	4,565	4.2
2006	3,819	2.1	4,246	2.5	4,696	2.9
2007	3,879	1.6	4,333	2.0	4,809	2.4
2008	3,906	0.7	4,381	1.1	4,881	1.5

Compound Average Annual Growth Rate

	LOW	MOST LIKELY	HIGH
1988-1998	1.8%	2.5%	3.2%
1988-2008	2.0%	2.6%	3.2%

FPL

Inter-Office Correspondence

To: DISTRIBUTION

Date: April 25, 1990

From: E. Ungar

Department: Fuel Resources

Subject: **FLORIDA POWER & LIGHT COMPANY: SHORT AND LONG-TERM FOSSIL FUEL PRICE AND NATURAL GAS AVAILABILITY FORECASTS**

Attached are the current official FPL Short and Long-Term Fossil Fuel Price Forecasts for crude oil, residual and distillate fuel oil, natural gas, and coal, as well as the current official projection for natural gas availability. These forecasts were approved by the Forecast Review Board on April 25, 1990 and supersede all previously released short and long-term fossil fuel price and natural gas availability forecasts, and are to be used for all official FPL planning, public disclosure and regulatory matters.

If you have any questions concerning these forecasts or any underlying assumption, please feel free to call.

E. Ungar

EU:bg
Attachment
FRFR-90-124

Capital Cost
for Combined Cy
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[illegible]

FPL

Inter-Office Correspondence

To: Distribution

Date: April 25, 1990

From: J. W. Williams, Jr.

Department: Miami - GO

Subject: **Florida Power & Light Company: Short and Long-Term Fossil Fuel Price and Natural Gas <u>Availability Forecasts</u>**

Attached are the current FPL Short and Long-Term Fossil Fuel Price Forecasts for crude oil, residual and distillate fuel oil, natural gas, and coal, as well as the current projection for natural gas availability. These forecasts were approved by the Forecast Review Board on April 25, 1990, are consistent with the base case set of integrated forecasting assumptions approved by the Forecast Review Board on March 16 and April 25, 1990, and are to be used for all official FPL planning, public disclosure and regulatory matters.

Questions concerning these forecasts or any underlying assumptions should be directed to Eugene Ungar on extension 3412 in the General Office.

J. W. Williams, Jr.
Senior Vice President
Chairman, Forecast Review Board

JWWJr:mls
attachments
FRBTT-90-39

Approved by:

R. E. Tallon
President & Chief Operating Officer
Florida Power & Light Company

<u>DISTRIBUTION:</u>
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APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

B A S E   C A S E   S C E N A R I O

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	*******DISTILLATE FUEL OIL************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
APR90	$16.00	$21.40	$21.60	$21.37	$22.02
MAY	$15.04	$19.99	$20.19	$19.88	$20.53
JUNE	$15.72	$20.83	$21.03	$20.72	$21.37
JULY	$16.82	$22.20	$22.40	$22.17	$22.82
AUG	$17.65	$23.35	$23.56	$23.24	$23.90
SEPT90	$17.19	$23.25	$23.46	$23.14	$23.80
OCT90	$17.76	$24.22	$24.42	$24.11	$24.77
NOV	$18.61	$25.03	$25.23	$24.92	$25.58
DEC	$20.75	$27.41	$27.62	$27.30	$27.96
JAN91	$19.40	$25.93	$26.14	$25.82	$26.48
FEB	$18.92	$25.33	$25.54	$25.22	$25.89
MAR	$17.91	$23.70	$23.90	$23.58	$24.25
APR91	$16.90	$22.51	$22.72	$22.39	$23.06
MAY91	$16.41	$21.62	$21.82	$21.50	$22.17
JUNE	$17.55	$22.97	$23.18	$22.85	$23.53
JULY	$18.68	$24.64	$24.85	$24.52	$25.20
AUG	$19.25	$25.40	$25.61	$25.28	$25.96
SEPT91	$18.80	$25.35	$25.56	$25.24	$25.92
OCT 91	$19.96	$27.10	$27.31	$26.98	$27.66
NOV	$21.11	$28.26	$28.48	$28.15	$28.83
DEC	$22.29	$30.09	$30.30	$29.97	$30.65
JAN 92	$22.94	$30.46	$30.67	$30.34	$31.03
FEB	$22.47	$29.86	$30.07	$29.74	$30.43
MAR	$21.71	$28.47	$28.69	$28.35	$29.05
APR92	$20.67	$27.27	$27.48	$27.15	$27.84
MAY92	$19.90	$25.96	$26.18	$25.84	$26.54
JUN	$21.11	$27.38	$27.60	$27.26	$27.96
JULY	$22.30	$29.19	$29.41	$29.07	$29.77
AUG	$22.67	$29.70	$29.92	$29.58	$30.29
SEP192	$22.18	$29.70	$29.92	$29.58	$30.29
OCT92	$22.54	$30.48	$30.70	$30.36	$31.07
NOV	$23.78	$31.71	$31.93	$31.59	$32.30
DEC	$25.00	$33.64	$33.87	$33.52	$34.24

DATE	***0.7% RESIDUAL** MARTIN	PUTNAM	***************1.0% SULFUR RESIDUAL FUEL OIL*********** CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	*******1.5% RESIDUAL******* CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
APR90	$16.01	$16.13	$15.56	$15.28	$15.03	$15.71	$14.99	$15.36	$16.35	$15.19	$14.76	$15.54	$14.23	$14.00
MAY	$16.23	$16.35	$15.70	$15.49	$15.24	$15.93	$15.20	$15.50	$16.56	$15.41	$14.97	$15.76	$14.44	$14.29
JUNE	$17.07	$17.19	$16.50	$16.79	$16.04	$16.73	$16.60	$16.30	$17.37	$16.21	$15.77	$16.56	$15.21	$15.09
JULY	$18.18	$18.29	$17.64	$17.35	$17.10	$17.79	$17.05	$17.43	$18.43	$17.26	$16.83	$17.62	$16.29	$16.15
AUG	$19.01	$19.13	$18.43	$18.14	$17.89	$18.50	$17.85	$18.23	$19.23	$18.06	$17.62	$18.41	$17.00	$16.94
SEPT90	$18.36	$18.48	$17.82	$17.53	$17.27	$17.97	$17.23	$17.61	$18.61	$17.44	$17.00	$17.80	$16.46	$16.33
OCT90	$19.12	$19.24	$18.54	$18.25	$17.99	$18.69	$17.95	$18.33	$19.34	$18.16	$17.72	$18.52	$17.18	$17.05
NOV	$19.78	$19.90	$19.17	$18.88	$18.62	$19.32	$18.58	$18.96	$19.97	$18.79	$18.35	$19.15	$17.80	$17.68
DEC	$21.62	$21.74	$20.93	$20.64	$20.39	$21.09	$20.34	$20.73	$21.74	$20.55	$20.11	$20.91	$19.56	$19.44
JAN91	$20.32	$20.44	$19.69	$19.39	$19.14	$19.84	$19.09	$19.48	$20.49	$19.30	$18.88	$19.68	$18.25	$18.19
FEB	$19.85	$19.97	$19.24	$18.94	$18.69	$19.39	$18.65	$19.03	$20.05	$18.86	$18.35	$19.16	$17.80	$17.74
MAR	$18.58	$18.70	$18.02	$17.73	$17.47	$18.18	$17.43	$17.82	$18.83	$17.64	$17.13	$17.94	$16.58	$16.52
APR91	$17.65	$17.77	$17.14	$16.84	$16.58	$17.29	$16.54	$16.93	$17.95	$16.75	$16.24	$17.05	$15.69	$15.64
MAY91	$16.96	$17.08	$16.48	$16.18	$15.92	$16.63	$15.87	$16.27	$17.29	$16.09	$15.57	$16.39	$15.02	$14.97
JUNE	$18.01	$18.13	$17.48	$17.18	$16.92	$17.64	$16.88	$17.27	$18.30	$17.09	$16.58	$17.48	$16.02	$15.98
JULY	$19.31	$19.43	$18.72	$18.42	$18.16	$18.88	$18.12	$18.51	$19.55	$18.34	$17.82	$18.64	$17.26	$17.22
AUG	$19.90	$20.02	$19.29	$18.99	$18.73	$19.45	$18.68	$19.08	$20.11	$18.90	$18.38	$19.21	$17.82	$17.78
SEPT91	$19.86	$19.99	$19.26	$18.95	$18.69	$19.41	$18.65	$19.05	$20.08	$18.87	$18.35	$19.17	$17.78	$17.75
OCT 91	$21.22	$21.35	$20.56	$20.25	$19.99	$20.71	$19.95	$20.34	$21.39	$20.16	$19.64	$20.47	$19.08	$19.05
NOV	$22.13	$22.26	$21.43	$21.12	$20.86	$21.58	$20.81	$21.21	$22.26	$21.03	$20.51	$21.34	$19.94	$19.91
DEC	$23.55	$23.67	$22.78	$22.48	$22.21	$22.94	$22.17	$22.57	$23.62	$22.39	$21.86	$22.70	$21.29	$21.27
JAN 92	$23.85	$23.98	$23.07	$22.76	$22.50	$23.23	$22.45	$22.86	$23.91	$22.68	$22.00	$22.84	$21.43	$21.56
FEB	$23.39	$23.51	$22.63	$22.32	$22.05	$22.79	$22.01	$22.41	$23.47	$22.23	$21.55	$22.39	$20.98	$21.11
MAR	$22.30	$22.43	$21.59	$21.28	$21.02	$21.75	$20.97	$21.38	$22.43	$21.19	$20.51	$21.36	$19.94	$20.07
APR92	$21.36	$21.49	$20.70	$20.39	$20.12	$20.86	$20.07	$20.48	$21.54	$20.30	$19.61	$20.46	$19.04	$19.18
MAY92	$20.35	$20.47	$19.72	$19.41	$19.14	$19.88	$19.10	$19.50	$20.57	$19.32	$18.64	$19.49	$18.06	$18.20
JUN	$21.45	$21.58	$20.78	$20.47	$20.20	$20.95	$20.16	$20.57	$21.64	$20.38	$19.69	$20.55	$19.11	$19.26
JULY	$22.86	$22.99	$22.13	$21.82	$21.55	$22.29	$21.50	$21.91	$22.98	$21.72	$21.04	$21.89	$20.45	$20.60
AUG	$23.26	$23.39	$22.51	$22.20	$21.93	$22.67	$21.88	$22.29	$23.37	$22.10	$21.41	$22.27	$20.83	$20.98
SEPT92	$23.26	$23.39	$22.51	$22.20	$21.93	$22.68	$21.88	$22.29	$23.38	$22.11	$21.41	$22.27	$20.83	$20.98
OCT92	$23.87	$24.00	$23.09	$22.78	$22.50	$23.26	$22.46	$22.87	$23.96	$22.68	$21.99	$22.85	$21.40	$21.56
NOV	$24.82	$24.95	$24.01	$23.69	$23.42	$24.17	$23.37	$23.78	$24.87	$23.60	$22.90	$23.76	$22.31	$22.47
DEC	$26.33	$26.46	$25.45	$25.13	$24.86	$25.62	$24.81	$25.23	$26.32	$25.04	$24.34	$25.21	$23.74	$23.91

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

B A S E   C A S E   S C E N A R I O

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	*******DISTILLATE FUEL OIL***************			
		EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN93	$26.57	$35.11	$35.33	$34.99	$35.71
FEB	$26.09	$34.50	$34.73	$34.38	$35.10
MAR	$25.31	$33.01	$33.24	$32.89	$33.61
APR93	$24.24	$31.78	$32.01	$31.66	$32.38
MAY 93	$23.45	$30.38	$30.61	$30.26	$30.99
JUN	$24.72	$31.88	$32.11	$31.76	$32.49
JUL	$25.99	$33.83	$34.06	$33.70	$34.44
AUG	$26.38	$34.39	$34.62	$34.26	$35.00
SEP93	$25.88	$34.48	$34.71	$34.36	$35.10
OCT93	$26.28	$35.35	$35.59	$35.23	$35.97
NOV	$27.58	$36.61	$36.85	$36.49	$37.23
DEC	$28.88	$38.70	$38.94	$38.58	$39.32
JAN94	$30.48	$40.13	$40.36	$40.00	$40.75
FEB	$29.99	$39.52	$39.75	$39.37	$40.14
MAR	$29.19	$37.92	$38.16	$37.79	$38.55
APR94	$28.09	$36.66	$36.90	$36.53	$37.29
MAY 94	$27.28	$35.17	$35.41	$35.04	$35.80
JUN	$28.63	$36.76	$37.00	$36.63	$37.39
JUL	$29.97	$38.86	$39.10	$38.73	$39.50
AUG	$30.40	$39.48	$39.72	$39.35	$40.12
SEP94	$29.90	$39.68	$39.92	$39.55	$40.32
OCT94	$30.33	$40.65	$40.90	$40.52	$41.30
NOV	$31.71	$41.96	$42.20	$41.83	$42.61
DEC	$33.11	$44.24	$44.48	$44.10	$44.89

DATE	**0.7% RESIDUAL**		****************1.0% SULFUR RESIDUAL FUEL OIL*************************************							*******1.5% RESIDUAL*******				READ: 1% SULFUR RESIDUAL FUEL OIL
	MARTIN	PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	CANAVERAL	SANFORD	FT MYERS	@ USGC
JAN93	$27.49	$27.62	$26.56	$26.23	$25.96	$26.72	$25.91	$26.33	$27.43	$26.14	$25.28	$26.15	$24.60	$25.02
FEB	$27.02	$27.15	$26.10	$25.78	$25.51	$26.27	$25.46	$25.88	$26.98	$25.69	$24.82	$25.70	$24.22	$24.56
MAR	$25.85	$25.99	$24.99	$24.67	$24.39	$25.16	$24.34	$24.77	$25.87	$24.58	$23.71	$24.59	$23.11	$23.45
APR93	$24.89	$25.03	$24.08	$23.75	$23.47	$24.24	$23.42	$23.85	$24.96	$23.66	$22.78	$23.67	$22.18	$22.53
MAY 93	$23.80	$23.94	$23.03	$22.71	$22.43	$23.20	$22.38	$22.81	$23.92	$22.61	$21.74	$22.62	$21.13	$21.49
JUN	$24.97	$25.11	$24.15	$23.83	$23.55	$24.32	$23.50	$23.92	$25.04	$23.73	$22.85	$23.74	$22.25	$22.61
JUL	$26.49	$26.62	$25.61	$25.28	$25.00	$25.77	$24.95	$25.38	$26.50	$25.18	$24.30	$25.19	$23.69	$24.06
AUG	$26.92	$27.06	$26.02	$25.69	$25.41	$26.19	$25.36	$25.79	$26.92	$25.60	$24.71	$25.61	$24.10	$24.47
SEP93	$27.00	$27.14	$26.09	$25.76	$25.48	$26.27	$25.43	$25.86	$26.99	$25.67	$24.78	$25.68	$24.16	$24.54
OCT93	$27.68	$27.81	$26.74	$26.41	$26.13	$26.91	$26.08	$26.51	$27.65	$26.31	$25.42	$26.32	$24.81	$25.19
NOV	$28.66	$28.80	$27.68	$27.35	$27.06	$27.85	$27.01	$27.45	$28.59	$27.25	$26.36	$27.26	$25.74	$26.13
DEC	$30.29	$30.42	$29.24	$28.91	$28.62	$29.41	$28.57	$29.01	$30.15	$28.81	$27.91	$28.82	$27.29	$27.68
JAN94	$31.42	$31.56	$30.32	$29.98	$29.70	$30.49	$29.65	$30.08	$31.23	$29.89	$28.81	$29.73	$28.19	$28.76
FEB	$30.94	$31.08	$29.86	$29.53	$29.24	$30.04	$29.19	$29.63	$30.78	$29.43	$28.35	$29.27	$27.72	$28.30
MAR	$29.70	$29.83	$28.67	$28.34	$28.05	$28.85	$27.99	$28.44	$29.39	$28.24	$27.16	$28.08	$26.53	$27.11
APR94	$28.71	$28.85	$27.74	$27.40	$27.10	$27.91	$27.05	$27.50	$28.66	$27.30	$26.21	$27.14	$25.58	$26.17
MAY 94	$27.55	$27.69	$26.62	$26.28	$25.99	$26.80	$25.94	$26.38	$27.55	$26.18	$25.09	$26.02	$24.46	$25.05
JUN	$28.78	$28.93	$27.81	$27.46	$27.17	$27.98	$27.12	$27.57	$28.74	$27.37	$26.27	$27.20	$25.64	$26.23
JUL	$30.43	$30.57	$29.38	$29.03	$28.74	$29.56	$28.69	$29.14	$30.31	$28.93	$27.84	$28.77	$27.20	$27.80
AUG	$30.91	$31.05	$29.84	$29.49	$29.20	$30.02	$29.14	$29.60	$30.78	$29.39	$28.29	$29.23	$27.65	$28.26
SEP94	$31.06	$31.21	$29.99	$29.64	$29.34	$30.17	$29.29	$29.75	$30.93	$29.54	$28.43	$29.38	$27.79	$28.41
OCT94	$31.82	$31.97	$30.72	$30.37	$30.07	$30.90	$30.02	$30.47	$31.66	$30.27	$29.16	$30.10	$28.51	$29.13
NOV	$32.84	$32.98	$31.69	$31.34	$31.04	$31.87	$30.99	$31.44	$32.64	$31.24	$30.12	$31.07	$29.47	$30.11
DEC	$34.62	$34.76	$33.39	$33.04	$32.74	$33.57	$32.68	$33.14	$34.34	$32.93	$31.81	$32.77	$31.16	$31.80

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

HEAD:

DELIVERED NOMINAL DOLLAR FUEL PRICES IN DOLLARS PER MMBTU

BASE CASE SCENARIO

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	*******DISTILLATE FUEL OIL*************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
APR90	$2.74	$3.69	$3.72	$3.67	$3.78
MAY	$2.58	$3.43	$3.46	$3.41	$3.52
JUNE	$2.70	$3.57	$3.61	$3.55	$3.66
JULY	$2.89	$3.82	$3.86	$3.80	$3.91
AUG	$3.03	$4.01	$4.04	$3.99	$4.10
SEPT90	$2.95	$3.99	$4.02	$3.97	$4.08
OCT90	$3.05	$4.15	$4.19	$4.14	$4.25
NOV	$3.19	$4.29	$4.33	$4.27	$4.39
DEC	$3.47	$4.70	$4.74	$4.68	$4.80
JAN91	$3.33	$4.45	$4.48	$4.43	$4.54
FEB	$3.25	$4.35	$4.38	$4.33	$4.44
MAR	$3.07	$4.06	$4.10	$4.05	$4.16
APR91	$2.90	$3.86	$3.90	$3.84	$3.96
MAY91	$2.81	$3.71	$3.74	$3.69	$3.80
JUNE	$3.01	$3.94	$3.98	$3.92	$4.04
JULY	$3.20	$4.23	$4.26	$4.21	$4.32
AUG	$3.30	$4.36	$4.39	$4.34	$4.45
SEPT91	$3.22	$4.35	$4.38	$4.33	$4.45
OCT 91	$3.42	$4.65	$4.68	$4.63	$4.74
NOV	$3.62	$4.85	$4.88	$4.83	$4.95
DEC	$3.82	$5.16	$5.20	$5.14	$5.26
JAN 92	$3.94	$5.22	$5.26	$5.20	$5.32
FEB	$3.85	$5.12	$5.16	$5.10	$5.22
MAR	$3.72	$4.88	$4.92	$4.86	$4.98
APR92	$3.55	$4.68	$4.71	$4.66	$4.78
MAY92	$3.41	$4.45	$4.49	$4.43	$4.55
JUN	$3.62	$4.70	$4.73	$4.68	$4.80
JULY	$3.83	$5.01	$5.04	$4.99	$5.11
AUG	$3.89	$5.09	$5.13	$5.07	$5.19
SEPT92	$3.80	$5.10	$5.13	$5.07	$5.20
OCT92	$3.87	$5.23	$5.27	$5.21	$5.33
NOV	$4.08	$5.44	$5.48	$5.42	$5.54
DEC	$4.29	$5.77	$5.81	$5.75	$5.87

DATE	***0.7% RESIDUAL*** MARTIN	PUTNAM	****1.0% SULFUR RESIDUAL FUEL OIL**** CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	****1.5% RESIDUAL**** CANAVERAL	SANFORD	FT MYERS	1% SULFUR RESIDUAL FUEL OIL 6 USGC
APR90	$2.51	$2.53	$2.45	$2.40	$2.36	$2.47	$2.36	$2.42	$2.57	$2.39	$2.32	$2.45	$2.24	$2.21
MAY	$2.55	$2.57	$2.48	$2.44	$2.40	$2.50	$2.39	$2.45	$2.60	$2.42	$2.36	$2.48	$2.27	$2.25
JUNE	$2.68	$2.70	$2.61	$2.56	$2.52	$2.63	$2.52	$2.58	$2.73	$2.55	$2.48	$2.61	$2.40	$2.37
JULY	$2.85	$2.87	$2.77	$2.73	$2.69	$2.80	$2.68	$2.74	$2.90	$2.71	$2.65	$2.77	$2.56	$2.54
AUG	$2.98	$3.00	$2.90	$2.85	$2.81	$2.92	$2.81	$2.87	$3.02	$2.84	$2.77	$2.90	$2.69	$2.66
SEPT90	$2.88	$2.90	$2.80	$2.76	$2.72	$2.83	$2.71	$2.77	$2.93	$2.74	$2.68	$2.80	$2.59	$2.57
OCT90	$3.00	$3.02	$2.91	$2.87	$2.83	$2.94	$2.82	$2.88	$3.04	$2.86	$2.79	$2.92	$2.70	$2.68
NOV	$3.10	$3.12	$3.01	$2.97	$2.93	$3.04	$2.92	$2.98	$3.14	$2.95	$2.89	$3.02	$2.80	$2.78
DEC	$3.39	$3.41	$3.29	$3.25	$3.21	$3.32	$3.20	$3.26	$3.42	$3.23	$3.17	$3.29	$3.00	$3.06
JAN91	$3.19	$3.21	$3.10	$3.05	$3.01	$3.12	$3.00	$3.06	$3.22	$3.04	$2.96	$3.09	$2.87	$2.86
FEB	$3.12	$3.14	$3.03	$2.98	$2.94	$3.05	$2.93	$2.99	$3.15	$2.97	$2.89	$3.02	$2.80	$2.79
MAR	$2.92	$2.94	$2.83	$2.79	[illegible]	$2.86	$2.74	$2.80	$2.96	$2.77	$2.70	$2.83	$2.61	$2.60
APR91	$2.77	$2.79	$2.69	$2.65	$2.61	$2.72	$2.60	$2.66	$2.82	$2.63	$2.56	$2.69	$2.47	$2.46
MAY91	$2.66	$2.68	$2.59	$2.54	$2.50	$2.61	$2.50	$2.56	$2.72	$2.53	$2.45	$2.58	$2.37	$2.35
JUNE	$2.83	$2.85	$2.75	$2.70	$2.66	$2.77	$2.65	$2.72	$2.88	$2.69	$2.61	$2.74	$2.52	$2.51
JULY	$3.03	$3.05	$2.94	$2.90	$2.86	$2.97	$2.85	$2.91	$3.07	$2.88	$2.81	$2.94	$2.72	$2.71
AUG	$3.12	$3.14	$3.03	$2.99	$2.94	$3.06	$2.94	$3.00	$3.16	$2.97	$2.89	$3.02	$2.81	$2.80
SEPT91	$3.12	$3.14	$3.03	$2.98	$2.94	$3.05	$2.93	$2.99	$3.16	$2.97	[illegible]	$3.02	$2.80	$2.79
OCT 91	$3.33	$3.35	-$3.23	$3.18	$3.14	$3.26	$3.14	$3.20	$3.36	$3.17	$3.99	$3.22	$3.00	$2.99
NOV	$3.47	$3.49	$3.37	$3.32	$3.28	$3.39	$3.27	$3.34	$3.50	$3.31	$3.23	$3.36	$3.14	$3.13
DEC	$3.70	$3.72	$3.58	$3.53	$3.49	$3.61	$3.49	$3.55	$3.71	$3.52	$3.44	$3.57	$3.35	$3.34
JAN 92	$3.74	$3.76	$3.63	$3.58	$3.54	$3.65	$3.53	$3.59	$3.76	$3.57	$3.46	$3.60	$3.37	$3.39
FEB	$3.67	$3.69	$3.56	$3.51	$3.47	$3.58	$3.46	$3.52	$3.69	$3.50	$3.39	$3.53	$3.30	$3.32
MAR	$3.50	$3.52	$3.40	$3.35	$3.30	$3.42	$3.30	$3.36	$3.53	$3.33	$3.23	$3.36	$3.14	$3.16
APR92	$3.35	$3.37	$3.25	$3.21	$3.16	$3.28	$3.16	$3.22	$3.39	$3.19	$3.09	$3.22	$3.00	$3.01
MAY92	$3.19	$3.21	$3.10	$3.05	$3.01	$3.13	$3.00	$3.07	$3.23	$3.04	$2.94	$3.07	$2.84	$2.86
JUN	$3.37	$3.39	$3.27	$3.22	$3.18	$3.29	$3.17	$3.23	$3.40	$3.20	$3.10	$3.24	$3.01	$3.03
JULY	$3.59	$3.61	$3.48	$3.43	$3.39	$3.51	$3.38	$3.44	$3.61	$3.42	$3.31	$3.45	$3.22	$3.24
AUG	$3.65	$3.67	$3.54	$3.49	$3.45	$3.56	$3.44	$3.50	$3.67	$3.48	$3.37	$3.51	$3.28	$3.30
SEPT92	$3.65	$3.67	$3.54	$3.49	$3.45	$3.57	$3.44	$3.51	$3.68	$3.48	$3.37	$3.51	$3.28	$3.30
OCT92	$3.75	$3.77	$3.63	$3.58	$3.54	$3.66	$3.53	$3.60	$3.77	$3.57	$3.46	$3.60	$3.37	$3.39
NOV	$3.90	$3.92	$3.77	$3.72	$3.68	$3.80	$3.67	$3.74	$3.91	$3.71	$3.61	$3.74	$3.51	$3.53
DEC	$4.13	$4.15	$4.00	$3.95	$3.91	$4.03	$3.90	$3.97	$4.14	$3.94	$3.83	$3.97	$3.74	$3.76

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   M M B T U

B A S E   C A S E   S C E N A R I O

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	*******DISTILLATE FUEL OIL*************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN93	$4.56	$6.02	$6.06	$6.00	$6.12
FEB	$4.47	$5.92	$5.96	$5.90	$6.02
MAR	$4.34	$5.66	$5.70	$5.64	$5.77
APR93	$4.16	$5.45	$5.49	$5.43	$5.55
MAY 93	$4.02	$5.21	$5.25	$5.19	$5.32
JUN	$4.24	$5.47	$5.51	$5.45	$5.57
JUL	$4.46	$5.80	$5.84	$5.78	$5.91
AUG	$4.53	$5.90	$5.94	$5.88	$6.00
SEP93	$4.44	$5.92	$5.95	$5.89	$6.02
OCT93	$4.51	$6.06	$6.10	$6.04	$6.17
NOV	$4.73	$6.28	$6.32	$6.26	$6.39
DEC	$4.95	$6.64	$6.68	$6.62	$6.75
JAN94	$5.23	$6.88	$6.92	$6.86	$6.99
FEB	$5.14	$6.78	$6.82	$6.76	$6.89
MAR	$5.01	$6.50	$6.55	$6.48	$6.61
APR94	$4.82	$6.29	$6.33	$6.27	$6.40
MAY 94	$4.68	$6.03	$6.07	$6.01	$6.14
JUN	$4.91	$6.30	$6.35	$6.28	$6.41
JUL	$5.14	$6.67	$6.71	$6.64	$6.78
AUG	$5.21	$6.77	$6.81	$6.75	$6.88
SEP94	$5.13	$6.81	$6.85	$6.78	$6.92
OCT94	$5.20	$6.97	$7.01	$6.95	$7.08
NOV	$5.44	$7.20	$7.24	$7.17	$7.31
DEC	$5.68	$7.59	$7.63	$7.56	$7.70

DATE	**0.7% RESIDUAL** MARTIN	***************1.0% SULFUR RESIDUAL FUEL OIL*************** PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	*******1.5% RESIDUAL****** TURKEY POINT	CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ UBOC
JAN93	$4.32	$4.34	$4.18	$4.12	$4.08	$4.20	$4.07	$4.14	$4.31	$4.11	$3.98	$4.12	$3.89	$3.93
FEB	$4.24	$4.26	$4.10	$4.05	$4.01	$4.13	$4.00	$4.07	$4.24	$4.04	$3.91	$4.05	$3.81	$3.86
MAR	$4.06	$4.08	$3.93	$3.88	$3.84	$3.96	$3.83	$3.89	$4.07	$3.86	$3.73	$3.87	$3.64	$3.69
APR93	$3.91	$3.93	$3.79	$3.73	$3.69	$3.81	$3.68	$3.75	$3.92	$3.72	$3.59	$3.73	$3.49	$3.54
MAY 93	$3.74	$3.76	$3.62	$3.57	$3.53	$3.65	$3.52	$3.59	$3.76	$3.56	$3.42	$3.56	$3.33	$3.38
JUN	$3.92	$3.94	$3.80	$3.75	$3.70	$3.82	$3.69	$3.76	$3.94	$3.73	$3.60	$3.74	$3.50	$3.55
JUL	$4.16	$4.18	$4.03	$3.97	$3.93	$4.05	$3.92	$3.99	$4.17	$3.96	$3.83	$3.97	$3.73	$3.78
AUG	$4.23	$4.25	$4.09	$4.04	$4.00	$4.12	$3.99	$4.06	$4.23	$4.02	$3.89	$4.03	$3.80	$3.85
SEP93	$4.24	$4.26	$4.10	$4.05	$4.01	$4.13	$4.00	$4.07	$4.24	$4.04	$3.90	$4.04	$3.81	$3.86
OCT93	$4.34	$4.37	$4.20	$4.15	$4.11	$4.23	$4.10	$4.17	$4.35	$4.14	$4.00	$4.15	$3.91	$3.96
NOV	$4.50	$4.52	$4.35	$4.30	$4.26	$4.38	$4.25	$4.32	$4.50	$4.29	$4.15	$4.29	$4.05	$4.11
DEC	$4.75	$4.78	$4.60	$4.54	$4.50	$4.62	$4.49	$4.56	$4.74	$4.53	$4.40	$4.54	$4.30	$4.35
JAN94	$4.93	$4.95	$4.77	$4.71	$4.67	$4.79	$4.66	$4.73	$4.91	$4.70	$4.54	$4.68	$4.44	$4.52
FEB	$4.86	$4.88	$4.70	$4.64	$4.60	$4.72	$4.59	$4.66	$4.84	$4.63	$4.46	$4.61	$4.37	$4.45
MAR	$4.66	$4.68	$4.51	$4.46	$4.41	$4.54	$4.40	$4.47	$4.65	$4.44	$4.28	$4.42	$4.18	$4.26
APR94	$4.51	$4.53	$4.36	$4.31	$4.26	$4.39	$4.25	$4.32	$4.51	$4.29	$4.13	$4.27	$4.03	$4.11
MAY 94	$4.32	$4.35	$4.19	$4.13	$4.09	$4.21	$4.08	$4.15	$4.33	$4.12	$3.95	$4.10	$3.85	$3.94
JUN	$4.52	$4.55	$4.37	$4.32	$4.27	$4.40	$4.26	$4.33	$4.52	$4.30	$4.14	$4.28	$4.04	$4.12
JUL	$4.78	$4.81	$4.62	$4.57	$4.52	$4.65	$4.51	$4.58	$4.77	$4.55	$4.38	$4.53	$4.28	$4.37
AUG	$4.85	$4.88	$4.69	$4.64	$4.59	$4.72	$4.58	$4.65	$4.84	$4.62	$4.46	$4.60	$4.35	$4.44
SEP94	$4.88	$4.91	$4.72	$4.66	$4.61	$4.74	$4.61	$4.68	$4.86	$4.64	$4.48	$4.63	$4.38	$4.47
OCT94	$5.00	$5.03	$4.83	$4.77	$4.73	$4.86	$4.72	$4.79	$4.98	$4.76	$4.59	$4.74	$4.49	$4.50
NOV	$5.16	$5.19	$4.98	$4.93	$4.88	$5.01	$4.87	$4.94	$5.13	$4.91	$4.74	$4.89	$4.64	$4.73
DEC	$5.43	$5.47	$5.25	$5.19	$5.15	$5.28	$5.14	$5.21	$5.40	$5.10	$5.01	$5.16	$4.91	$5.00

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED 1990 DOLLAR FUEL PRICES IN DOLLARS PER BARREL

BASE CASE SCENARIO

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	EVERGLADES (DISTILLATE FUEL OIL)	LAUDERDALE (DISTILLATE FUEL OIL)	FT MYERS (DISTILLATE FUEL OIL)	PUTNAM (DISTILLATE FUEL OIL)
APR90	$16.00	$21.49	$21.69	$21.38	$22.02
MAY	$15.00	$19.94	$20.14	$19.83	$20.67
JUNE	$15.63	$20.71	$20.91	$20.60	$21.25
JULY	$16.67	$22.10	$22.30	$21.99	$22.63
AUG	$17.44	$23.09	$23.29	$22.98	$23.63
SEPT90	$16.93	$22.93	$23.13	$22.82	$23.46
OCT90	$17.44	$23.81	$24.01	$23.70	$24.35
NOV	$18.22	$24.54	$24.74	$24.43	$25.07
DEC	$19.77	$26.79	$26.99	$26.68	$27.33
JAN91	$18.88	$25.27	$25.47	$25.16	$25.80
FEB	$18.36	$24.61	$24.81	$24.50	$25.15
MAR	$17.32	$22.96	$23.16	$22.85	$23.49
APR91	$16.29	$21.74	$21.94	$21.63	$22.28
MAY91	$15.77	$20.82	$21.02	$20.71	$21.35
JUNE	$16.81	$22.05	$22.25	$21.94	$22.59
JULY	$17.84	$23.58	$23.78	$23.47	$24.11
AUG	$18.33	$24.23	$24.43	$24.12	$24.77
SEPT91	$17.84	$24.11	$24.31	$24.00	$24.65
OCT 91	$18.88	$25.69	$25.89	$25.58	$26.23
NOV	$19.91	$26.71	$26.91	$26.60	$27.25
DEC	$20.95	$28.35	$28.55	$28.24	$28.88
JAN 92	$21.49	$28.60	$28.80	$28.49	$29.13
FEB	$20.97	$27.94	$28.14	$27.83	$28.48
MAR	$20.19	$26.55	$26.75	$26.44	$27.09
APR92	$19.16	$25.35	$25.55	$25.24	$25.88
MAY92	$18.38	$24.05	$24.25	$23.94	$24.59
JUN	$19.42	$25.28	$25.48	$25.17	$25.82
JULY	$20.45	$26.85	$27.05	$26.74	$27.39
AUG	$20.71	$27.22	$27.42	$27.11	$27.76
SEPT92	$20.19	$27.14	$27.34	$27.03	$27.67
OCT92	$20.45	$27.75	$27.95	$27.64	$28.28
NOV	$21.49	$28.76	$28.96	$28.65	$29.29
DEC	$22.52	$30.41	$30.61	$30.30	$30.94

DATE	MARTIN (0.7% RESIDUAL)	PUTNAM (0.7% RESIDUAL)	CANAVERAL (1.0% SULFUR RESIDUAL FUEL OIL)	EVERGLADES (1.0%)	FT MYERS (1.0%)	LAUDERDALE (1.0%)	MANATEE (1.0%)	RIVIERA (1.0%)	SANFORD (1.0%)	TURKEY POINT (1.0%)	CANAVERAL (1.5% RESIDUAL)	SANFORD (1.5% RESIDUAL)	FT MYERS & USAC (1.5% RESIDUAL)	MEMO: 1% SULFUR RESIDUAL FUEL OIL
APR90	$16.01	$16.13	$15.57	$15.28	$15.03	$15.72	$14.99	$15.37	$16.35	$15.20	$14.76	$15.55	$14.23	$14.00
MAY	$16.19	$16.31	$15.74	$15.45	$15.20	$15.89	$15.16	$15.54	$16.52	$15.37	$14.93	$15.72	$14.40	$14.25
JUNE	$16.98	$17.10	$16.49	$16.20	$15.96	$16.64	$15.91	$16.29	$17.28	$16.12	$15.69	$16.47	$15.15	$15.00
JULY	$18.03	$18.14	$17.49	$17.20	$16.96	$17.64	$16.91	$17.29	$18.27	$17.12	$16.69	$17.47	$16.15	$16.00
AUG	$18.80	$18.92	$18.23	$17.94	$17.70	$18.38	$17.65	$18.03	$19.01	$17.86	$17.43	$18.21	$16.89	$16.74
SEPT90	$18.11	$18.23	$17.57	$17.28	$17.04	$17.72	$16.99	$17.37	$18.35	$17.20	$16.77	$17.55	$16.23	$16.08
OCT90	$18.80	$18.92	$18.23	$17.94	$17.70	$18.38	$17.65	$18.03	$19.01	$17.86	$17.43	$18.21	$16.89	$16.74
NOV	$19.39	$19.51	$18.80	$18.34	$18.26	$18.95	$18.22	$18.60	$19.58	$18.43	$17.99	$18.78	$17.46	$17.31
DEC	$21.14	$21.26	$20.47	$20.18	$19.93	$20.62	$19.89	$20.27	$21.25	$20.10	$19.66	$20.45	$19.13	$18.98
JAN91	$19.80	$19.92	$19.19	$18.90	$18.65	$19.34	$18.61	$18.99	$19.97	$18.82	$18.32	$19.11	$17.79	$17.70
FEB	$19.29	$19.41	$18.70	$18.41	$18.17	$18.85	$18.12	$18.50	$19.49	$18.33	$17.84	$18.62	$17.30	$17.21
MAR	$18.00	$18.12	$17.47	$17.18	$16.93	$17.62	$16.89	$17.27	$18.25	$17.10	$16.60	$17.39	$16.07	$15.98
APR91	$17.06	$17.18	$16.56	$16.28	$16.03	$16.71	$15.99	$16.36	$17.35	$16.19	$15.70	$16.48	$15.16	$15.08
MAY91	$16.34	$16.46	$15.88	$15.59	$15.34	$16.03	$15.30	$15.68	$16.66	$15.51	$15.01	$15.79	$14.48	$14.39
JUNE	$17.30	$17.42	$16.79	$16.51	$16.26	$16.94	$16.22	$16.59	$17.58	$16.42	$15.93	$16.71	$15.39	$15.31
JULY	$18.49	$18.61	$17.93	$17.64	$17.40	$18.08	$17.35	$17.73	$18.72	$17.56	$17.07	$17.85	$16.53	$16.44
AUG	$19.00	$19.11	$18.42	$18.13	$17.88	$18.57	$17.84	$18.22	$19.20	$18.05	$17.55	$18.34	$17.02	$16.93
SEPT91	$18.91	$19.02	$18.33	$18.04	$17.80	$18.48	$17.75	$18.13	$19.11	$17.96	$17.47	$18.25	$16.95	$16.84
OCT 91	$20.14	$20.25	$19.51	$19.22	$18.97	$19.65	$18.93	$19.30	$20.29	$19.13	$18.64	$19.42	$18.11	$18.02
NOV	$20.93	$21.05	$20.27	$19.98	$19.73	$20.42	$19.69	$20.07	$21.05	$19.89	$19.40	$20.18	$18.87	$18.78
DEC	$22.20	$22.32	$21.48	$21.19	$20.95	$21.63	$20.90	$21.28	$22.27	$21.11	$20.62	$21.40	$20.08	$19.79
JAN 92	$22.41	$22.53	$21.68	$21.39	$21.15	$21.83	$21.10	$21.48	$22.46	$21.31	$20.60	$21.46	$20.14	$20.19
FEB	$21.90	$22.02	$21.19	$20.90	$20.66	$21.34	$20.61	$20.99	$21.97	$20.82	$20.19	$20.97	$19.65	$19.70
MAR	$20.82	$20.94	$20.16	$19.87	$19.62	$20.31	$19.58	$19.96	$20.94	$19.79	$19.15	$19.94	$18.62	$18.67
APR92	$19.88	$20.00	$19.26	$18.97	$18.72	$19.41	$18.68	$19.06	$20.04	$18.89	$18.26	$19.04	$17.52	$17.77
MAY92	$18.87	$18.99	$18.29	$18.01	$17.76	$18.44	$17.72	$18.09	$19.08	$17.92	$17.29	$18.08	$16.76	$16.81
JUN	$19.83	$19.94	$19.21	$18.92	$18.67	$19.36	$18.63	$19.01	$19.99	$18.84	$18.21	$18.99	$17.67	$17.72
JULY	$21.05	$21.17	$20.38	$20.09	$19.84	$20.53	$19.80	$20.18	$21.16	$20.01	$19.38	$20.16	$18.84	$18.89
AUG	$21.34	$21.46	$20.66	$20.37	$20.12	$20.81	$20.08	$20.46	$21.44	$20.29	$19.65	$20.44	$19.12	$19.17
SEPT92	$21.27	$21.39	$20.59	$20.30	$20.06	$20.74	$20.01	$20.39	$21.37	$20.22	$19.59	$20.37	$19.05	$19.10
OCT92	$21.75	$21.87	$21.05	$20.76	$20.51	$21.20	$20.47	$20.85	$21.83	$20.67	$20.04	$20.83	$19.51	$19.56
NOV	$22.54	$22.66	$21.80	$21.51	$21.27	$21.95	$21.22	$21.60	$22.58	$21.43	$20.80	$21.58	$20.26	$20.31
DEC	$23.82	$23.94	$23.03	$22.74	$22.49	$23.17	$22.45	$22.82	$23.81	$22.65	$22.02	$22.81	$21.49	$21.54

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D 1 9 9 0 D O L L A R F U E L P R I C E S I N D O L L A R S P E R B A R R E L

B A S E C A S E S C E N A R I O

APRIL 25, 1990

DATE	WORLD CRUDE OIL PRICES	DISTILLATE FUEL OIL: EVERGLADES	DISTILLATE FUEL OIL: LAUDERDALE	DISTILLATE FUEL OIL: FT MYERS	DISTILLATE FUEL OIL: PUTNAM
JAN93	$23.04	$31.61	$31.81	$31.50	$32.15
FEB	$23.32	$30.95	$31.15	$30.84	$31.49
MAR	$22.54	$29.52	$29.72	$29.41	$30.05
APR93	$21.51	$28.32	$28.52	$28.21	$28.85
MAY 93	$20.73	$26.98	$27.18	$26.87	$27.51
JUN	$21.77	$28.20	$28.40	$28.09	$28.74
JUL	$22.80	$29.81	$30.01	$29.70	$30.34
AUG	$23.06	$30.19	$30.39	$30.08	$30.73
SEP93	$22.54	$30.17	$30.37	$30.06	$30.70
OCT93	$22.80	$30.81	$31.01	$30.70	$31.35
NOV	$23.84	$31.79	$31.99	$31.68	$32.33
DEC	$24.87	$33.47	$33.67	$33.36	$34.01
JAN94	$26.14	$34.57	$34.77	$34.46	$35.10
FEB	$25.62	$33.91	$34.11	$33.80	$34.45
MAR	$24.84	$32.42	$32.62	$32.31	$32.96
APR94	$23.81	$31.23	$31.43	$31.12	$31.77
MAY 94	$23.03	$29.85	$30.05	$29.74	$30.39
JUN	$24.07	$31.07	$31.27	$30.96	$31.61
JUL	$25.10	$32.72	$32.92	$32.61	$33.25
AUG	$25.36	$33.10	$33.30	$32.99	$33.64
SEP94	$24.84	$33.14	$33.34	$33.03	$33.68
OCT94	$25.10	$33.82	$34.02	$33.71	$34.36
NOV	$26.14	$34.77	$34.97	$34.66	$35.30
DEC	$27.10	$36.50	$36.70	$36.39	$37.04

DATE	0.7% RESIDUAL: MARTIN	1.0% SULFUR RESIDUAL FUEL OIL: PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	1.5% RESIDUAL: CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
JAN93	$24.77	$24.09	$23.94	$23.65	$23.40	$24.08	$23.36	$23.73	$24.72	$23.56	$22.79	$23.57	$22.25	$22.45
FEB	$24.26	$24.38	$23.45	$23.16	$22.91	$23.59	$22.87	$23.24	$24.23	$23.07	$22.30	$23.08	$21.77	$21.96
MAR	$23.14	$23.26	$22.37	$22.09	$21.84	$22.52	$21.80	$22.17	$23.16	$22.00	$21.23	$22.01	$20.69	$20.89
APR93	$22.20	$22.32	$21.48	$21.19	$20.95	$21.63	$20.90	$21.28	$22.26	$21.11	$20.33	$21.12	$19.80	$19.99
MAY 93	$21.16	$21.28	$20.48	[illegible]	$19.93	$20.63	$19.91	$20.28	$21.27	$20.11	$19.34	$20.12	$18.80	$19.00
JUN	$22.12	$22.23	$21.40	$21.11	$20.86	$21.54	$20.82	$21.19	$22.18	$21.02	$20.25	$21.03	$19.71	$19.91
JUL	$23.37	$23.49	$22.59	$22.31	$22.06	$22.74	$22.02	$22.39	$23.38	$22.22	$21.45	$22.23	$20.91	$21.11
AUG	$23.67	$23.78	$22.88	$22.59	$22.34	$23.03	$22.30	$22.68	$23.66	$22.51	$21.73	$22.51	$21.20	$21.39
SEP93	$23.65	$23.77	$22.86	$22.57	$22.32	$23.01	$22.28	$22.66	$23.64	$22.49	$21.71	$22.50	$21.18	$21.37
OCT93	$24.15	$24.27	$23.34	$23.05	$22.81	$23.49	$22.76	$23.14	$24.12	$22.97	$22.19	$22.98	$21.66	$21.85
NOV	$24.91	$25.03	$24.07	$23.78	$23.54	$24.22	$23.49	$23.87	$24.85	$23.70	$22.92	$23.71	$22.39	$22.58
DEC	$26.23	$26.35	$25.32	$25.04	$24.79	$25.47	$24.75	$25.12	$26.11	$24.95	$24.18	$24.96	$23.64	$23.84
JAN94	$27.10	$27.22	$26.15	$25.87	$25.62	$26.30	$25.58	$25.95	$26.94	$25.78	$24.86	$25.65	$24.33	$24.67
FEB	$26.58	$26.70	$25.66	$25.38	$25.13	$25.81	$25.09	$25.46	$26.45	$25.29	$24.37	$25.16	$23.84	$24.18
MAR	$25.42	$25.54	$24.55	$24.27	$24.02	$24.70	$23.98	$24.35	$25.34	$24.18	$23.26	$24.05	$22.73	$23.07
APR94	$24.49	$24.61	$23.67	$23.38	$23.13	$23.81	$23.09	$23.46	$24.45	$23.29	$22.37	$23.16	$21.84	$22.18
MAY 94	$23.42	$23.53	$22.64	$22.35	$22.10	$22.78	$22.06	$22.43	$23.42	$22.26	$21.35	$22.13	[illegible]	$21.15
JUN	$24.37	$24.46	$23.55	$23.26	$23.01	$23.69	$22.97	$23.34	$24.33	$23.17	$22.26	$23.04	$21.72	$22.06
JUL	$25.65	$25.77	$24.77	$24.48	$24.24	$24.92	$24.19	$24.57	$25.56	$24.40	$23.48	$24.27	$22.95	$23.28
AUG	$25.95	$26.07	$25.06	$24.77	$24.53	$25.21	$24.48	$24.86	$25.84	$24.69	$23.77	$24.55	[illegible]	$23.57
SEP94	$25.98	$26.10	$25.09	$24.80	$24.56	$25.24	$24.51	$24.89	$25.87	$24.72	$23.80	$24.58	$23.26	$23.60
OCT94	$26.51	$26.63	$25.60	$25.31	$25.06	$25.75	$25.02	$25.40	$26.38	$25.23	$24.31	$25.09	$23.77	$24.11
NOV	$27.25	$27.37	$26.30	$26.01	$25.77	$26.45	$25.72	$26.10	$27.08	$25.93	$25.01	$25.79	$24.48	$24.81
DEC	$28.60	$28.72	$27.59	$27.31	$27.06	$27.74	$27.02	$27.39	$28.38	$27.22	$26.30	$27.09	$25.77	$26.11

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED 1990 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU &
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

BASE CASE SCENARIO

APRIL 25, 1990

DATE	********INTERRUPTIBLE SERVICE**** P10 GAS $/MMBTU 1990$	NOMINAL	SPOT GAS $/MMBTU 1990$	NOMINAL	********FIRM SERVICE************ SPOT GAS $/MMBTU 1990$	NOMINAL	AMOCO/CITRUS GAS $/MMBTU 1990$	NOMINAL	AVERAGE GAS PRICE $/MMBTU 1990$	NOMINAL	**********NATURAL GAS AVAILABILITY*********** MILLION CUBIC FEET PER DAY INTERRUPTIBLE SERVICE P10	INTERRUPTIBLE SERVICE SPOT	FIRM SERVICE SPOT	FIRM	TOTAL DATE	HRMO: SPOT/MARKET GAS @ USGC $/MMBTU 1990$	NOMINAL	*********TRANSPORTATION SERVICE********** INTERRUPTIBLE $/MMBTU 1990$	NOMINAL	FIRM $/MMBTU 1990$	NOMINAL
APR90	02.12	02.12					02.02	02.02	02.12	02.12	372			5	377 APR90	01.44	01.44				
MAY	02.15	02.16					02.08	02.09	02.15	02.15	387			5	392 MAY	01.50	01.51				
JUNE	02.26	02.28	01.95	01.97	02.01	02.02	02.38	02.40	02.34	02.36	0	0	39	353	392 JUNE	01.63	01.64	00.33	00.33	00.38	00.38
JULY	02.41	02.44	02.07	02.08	02.12	02.14	02.54	02.56	02.50	02.52	0	0	39	353	392 JULY	01.74	01.75	00.33	00.33	00.38	00.38
AUG	02.52	02.56	02.23	02.25	02.26	02.31	02.66	02.69	02.62	02.65	0	0	39	353	392 AUG	01.90	01.92	00.33	00.34	00.38	00.39
SEPT90	02.43	02.46	02.28	02.31	02.33	02.36	02.55	02.59	02.53	02.57	0	0	39	353	392 SEPT90	01.95	01.98	00.33	00.34	00.38	00.39
OCT90	02.52	02.57	02.44	02.48	02.49	02.54	02.66	02.71	02.59	02.64	59	58	28	252	397 OCT90	02.11	02.14	00.33	00.34	00.38	00.39
NOV	02.61	02.67	02.62	02.68	02.67	02.73	02.75	02.81	02.68	02.74	179	0	24	221	424 NOV	02.29	02.33	00.33	00.34	00.39	00.39
DEC	02.86	02.93	02.97	03.04	03.02	03.09	03.01	03.09	02.96	03.03	140	0	0	245	385 DEC	02.63	02.69	00.34	00.35	00.39	00.40
JAN91	02.67	02.74	02.59	02.66	02.64	02.71	02.81	02.89	02.79	02.87	0	0	24	221	245 JAN91	02.25	02.32	00.33	00.34	00.39	00.40
FEB	02.60	02.68	02.50	02.57	02.55	02.63	02.73	02.82	02.69	02.78	18	18	24	221	281 FEB	02.17	02.23	00.33	00.34	00.38	00.40
MAR	02.41	02.49	02.29	02.37	02.34	02.42	02.54	02.62	02.47	02.56	40	39	24	221	324 MAR	01.96	02.03	00.33	00.34	00.38	00.39
APR91	02.27	02.36	02.05	02.13	02.11	02.18	02.39	02.48	02.32	02.41	39	38	28	252	357 APR91	01.73	01.79	00.32	00.34	00.38	00.39
MAY91	02.17	02.26	01.81	01.89	01.86	01.94	02.28	02.38	02.24	02.33	0	0	39	353	392 MAY91	01.49	01.55	00.32	00.33	00.37	00.39
JUNE	02.31	02.41	01.94	02.02	01.99	02.07	02.43	02.54	02.39	02.49	0	0	39	353	392 JUNE	01.61	01.68	00.32	00.34	00.37	00.39
JULY	02.48	02.60	02.06	02.15	02.11	02.21	02.61	02.73	02.56	02.68	0	0	39	353	392 JULY	01.73	01.81	00.33	00.34	00.38	00.39
AUG	02.55	02.68	02.19	02.30	02.24	02.35	02.69	02.82	02.64	02.78	0	0	39	353	392 AUG	01.86	01.96	00.33	00.34	00.38	00.40
SEPT91	02.54	02.68	02.34	02.47	02.39	02.52	02.67	02.82	02.65	02.79	0	0	39	353	392 SEPT91	02.01	02.12	00.33	00.35	00.38	00.40
OCT 91	02.72	02.87	02.54	02.69	02.59	02.74	02.86	03.02	02.78	02.94	50	49	28	252	379 OCT 91	02.21	02.34	00.33	00.35	00.38	00.40
NOV	02.83	03.00	02.76	02.92	02.81	02.98	02.87	03.04	02.83	03.01	82	82	25	230	419 NOV	02.42	02.57	00.33	00.35	00.39	00.41
DEC	03.02	03.21	03.17	03.37	03.22	03.42	03.05	03.25	03.04	03.23	114	0	0	255	369 DEC	02.83	03.01	00.34	00.36	00.39	00.41
JAN 92	03.04	03.25	02.96	03.16	03.01	03.22	03.07	03.28	03.05	03.26	26	26	25	230	307 JAN 92	02.63	02.88	00.34	00.36	00.39	00.42
FEB	02.97	03.18	02.87	03.07	02.92	03.13	03.00	03.22	02.97	03.18	51	51	25	230	357 FEB	02.53	02.71	00.34	00.36	00.39	00.41
MAR	02.82	03.03	02.70	02.90	02.75	02.96	02.85	03.06	02.80	03.02	74	73	25	230	402 MAR	02.37	02.55	00.33	00.36	00.38	00.41
APR92	02.68	02.89	02.44	02.64	02.49	02.69	02.74	02.95	02.66	02.87	79	78	28	252	437 APR92	02.12	02.28	00.33	00.35	00.38	00.41
MAY92	02.53	02.74	02.22	02.40	02.27	02.46	02.61	02.83	02.58	02.79	3	3	43	307	436 MAY92	01.89	02.05	00.32	00.35	00.37	00.40
JUN	02.67	02.90	02.30	02.49	02.35	02.55	02.71	02.95	02.67	02.91	3	3	43	307	436 JUN	01.97	02.14	00.33	00.35	00.38	00.41
JULY	02.85	03.11	02.43	02.65	02.48	02.70	02.86	03.12	02.81	03.07	14	13	43	307	457 JULY	02.10	02.29	00.33	00.36	00.38	00.41
AUG	02.89	03.16	02.55	02.79	02.60	02.85	02.91	03.18	02.88	03.15	0	0	43	307	430 AUG	02.22	02.43	00.33	00.36	00.38	00.42
SEPT92	02.88	03.16	02.72	02.99	02.77	03.05	02.91	03.20	02.89	03.18	11	11	43	307	432 SEPT92	02.39	02.63	00.33	00.36	00.38	00.42
OCT92	02.95	03.25	02.84	03.14	02.89	03.19	02.98	03.28	02.94	03.24	90	89	28	252	459 OCT92	02.51	02.77	00.33	00.37	00.38	00.42
NOV	03.06	03.39	03.07	03.40	03.12	03.45	03.09	03.42	03.08	03.40	233	0	0	255	480 NOV	02.74	03.03	00.33	00.37	00.38	00.42
DEC	03.25	03.61	03.51	03.90	03.56	03.95	03.28	03.64	03.26	03.62	190	0	0	255	445 DEC	03.17	03.52	00.34	00.38	00.39	00.43

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED 1990 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU &
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

BASE CASE SCENARIO

APRIL 25, 1990

	********INTERRUPTIBLE SERVICE****				********FIRM SERVICE***********					
	P10 GAS $/MMBTU		SPOT GAS $/MMBTU		SPOT GAS $/MMBTU		AMOCO/CITRUS GAS $/MMBTU		AVERAGE GAS PRICE $/MMBTU	
DATE	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL
JAN93	$3.39	$3.77	$3.30	$3.76	$3.65	$4.02	$3.40	$3.79	$3.40	$3.79
FEB	$3.31	$3.70	$3.27	$3.66	$3.32	$3.72	$3.33	$3.72	$3.32	$3.71
MAR	$3.15	$3.54	$3.06	$3.44	$3.11	$3.49	$3.17	$3.56	$3.14	$3.53
APR93	$3.01	$3.40	$2.78	$3.14	$2.83	$3.19	$3.03	$3.42	$2.98	$3.36
MAY 93	$2.86	$3.24	$2.45	$2.77	$2.49	$2.82	$2.87	$3.25	$2.83	$3.20
JUN	$3.09	$3.41	$2.58	$2.93	$2.63	$2.99	$3.01	$3.41	$2.97	$3.36
JUL	$3.18	$3.63	$2.72	$3.10	$2.77	$3.16	$3.18	$3.62	$3.14	$3.57
AUG	$3.23	$3.69	$2.85	$3.27	$2.90	$3.32	$3.23	$3.69	$3.19	$3.65
SEP93	$3.22	$3.70	$3.05	$3.51	$3.10	$3.56	$3.24	$3.72	$3.23	$3.70
OCT93	$3.30	$3.80	$3.19	$3.67	$3.25	$3.73	$3.31	$3.82	$3.28	$3.78
NOV	$3.41	$3.94	$3.43	$3.96	$3.47	$4.02	$3.42	$3.95	$3.41	$3.95
DEC	$3.59	$4.17	$3.90	$4.53	$3.95	$4.59	$3.61	$4.19	$3.72	$4.31
JAN94	$3.72	$4.34	$3.68	$4.29	$3.73	$4.34	$3.72	$4.34	$3.71	$4.33
FEB	$3.65	$4.27	$3.57	$4.18	$3.62	$4.24	$3.65	$4.27	$3.63	$4.25
MAR	$3.48	$4.09	$3.38	$3.98	$3.43	$4.03	$3.49	$4.10	$3.46	$4.07
APR94	$3.34	$3.95	$3.09	$3.64	$3.13	$3.70	$3.35	$3.95	$3.30	$3.88
MAY 94	$3.19	$3.78	$2.85	$3.38	$2.90	$3.44	$3.19	$3.78	$3.16	$3.74
JUN	$3.33	$3.96	$2.90	$3.44	$2.94	$3.50	$3.30	$3.92	$3.26	$3.87
JUL	$3.51	$4.19	$3.04	$3.63	$3.09	$3.69	$3.47	$4.15	$3.44	$4.10
AUG	$3.55	$4.26	$3.19	$3.82	$3.24	$3.88	$3.52	$4.22	$3.50	$4.18
SEP94	$3.56	$4.28	$3.42	$4.11	$3.46	$4.17	$3.54	$4.27	$3.54	$4.25
OCT94	$3.64	$4.39	$3.56	$4.30	$3.61	$4.36	$3.62	$4.37	$3.61	$4.36
NOV	$3.74	$4.54	$3.81	$4.62	$3.86	$4.68	$3.72	$4.51	$3.73	$4.53
DEC	$3.94	$4.80	$4.33	$5.27	$4.37	$5.33	$3.92	$4.77	$4.07	$4.96

***********NATURAL GAS AVAILABILITY***********						MEMO: SPOT/MARKET		**********TRANSPORTATION SERVICE**********			
MILLION CUBIC FEET PER DAY						GAS @ UGDC $/MMBTU		INTERRUPTIBLE $/MMBTU		FIRM $/MMBTU	
INTERRUPTIBLE SERVICE P10	INTERRUPTIBLE SERVICE SPOT	FIRM SERVICE SPOT	FIRM	TOTAL	DATE	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL
0	0	0	255	255	JAN93	$3.04	$3.38	$0.34	$0.38	$0.39	$0.43
24	24	25	230	303	FEB	$2.93	$3.28	$0.34	$0.38	$0.39	$0.43
49	48	25	230	352	MAR	$2.73	$3.06	$0.33	$0.38	$0.38	$0.43
56	55	28	252	391	APR93	$2.45	$2.76	$0.33	$0.37	$0.38	$0.43
0	[illegible]	43	387	430	MAY 93	$2.12	$2.40	$0.33	$0.37	$0.37	$0.42
0	0	43	387	430	JUN	$2.25	$2.56	$0.33	$0.37	$0.38	$0.43
0	0	43	387	430	JUL	$2.39	$2.72	$0.33	$0.38	$0.38	$0.43
0	0	43	387	430	AUG	$2.52	$2.89	$0.33	$0.38	$0.38	$0.44
0	0	43	387	430	SEP93	$2.72	$3.13	$0.33	$0.38	$0.38	$0.44
68	67	28	252	415	OCT93	$2.85	$3.29	$0.33	$0.39	$0.38	$0.44
192	0	0	255	447	NOV	$3.09	$3.57	$0.34	$0.39	$0.39	$0.45
0	145	0	255	400	DEC	$3.56	$4.13	$0.34	$0.40	$0.39	$0.45
1	0	0	255	256	JAN94	$3.34	$3.89	$0.34	$0.40	$0.39	$0.46
28	27	25	230	310	FEB	$3.23	$3.78	$0.34	$0.40	$0.39	$0.45
52	52	25	230	339	MAR	$3.05	$3.58	$0.34	$0.40	$0.38	$0.45
58	58	28	252	396	APR94	$2.75	$3.25	$0.33	$0.39	$0.38	$0.45
0	0	43	387	430	MAY 94	$2.53	$2.99	$0.33	$0.39	$0.38	$0.44
0	0	43	387	430	JUN	$2.57	$3.05	$0.33	$0.39	$0.38	$0.45
0	0	43	387	430	JUL	$2.71	$3.24	$0.33	$0.40	$0.38	$0.45
0	0	43	387	430	AUG	$2.85	$3.42	$0.33	$0.40	$0.38	$0.46
0	0	43	387	430	SEP94	$3.08	$3.71	$0.34	$0.40	$0.38	$0.46
0	0	28	252	421	OCT94	$3.22	$3.89	$0.34	$0.41	$3.38	$0.46
71	70	0	255	452	NOV	$3.47	$4.21	$0.34	$0.41	$0.39	$0.47
197	0	0	255	406	DEC	$3.98	$4.85	$0.35	$0.42	$0.39	$0.48
0	151	0									

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED 1990 DOLLAR & NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON &
PER MMBTU
BASE CASE SCENARIO

APRIL 25, 1990

DATE	ST. JOHNS RIVER POWER PARK COAL (WEIGHTED AVERAGE CONTRACT/SPOT PRICE) $/TON 1990$	$/TON NOMINAL	$/MMBTU 1990$	$/MMBTU NOMINAL	ST. JOHNS RIVER POWER PARK COAL SPOT COAL PRICE $/TON 1990$	$/TON NOMINAL	$/MMBTU 1990$	$/MMBTU NOMINAL
APR90	$45.25	$45.25	$1.81	$1.81	$41.75	$41.75	$1.67	$1.67
MAY	$45.11	$45.25	$1.80	$1.81	$41.63	$41.75	$1.67	$1.67
JUNE	$43.74	$44.00	$1.75	$1.76	$41.50	$41.75	$1.66	$1.67
JULY	$43.36	$43.75	$1.73	$1.75	$41.62	$42.00	$1.66	$1.68
AUG	$40.02	$40.50	$1.60	$1.62	$40.27	$40.75	$1.61	$1.63
SEPT90	$39.90	$40.50	$1.60	$1.62	$40.15	$40.75	$1.61	$1.63
OCT90	$40.03	$40.75	$1.60	$1.63	$40.03	$40.75	$1.60	$1.63
NOV	$39.17	$40.00	$1.57	$1.60	$39.17	$40.00	$1.57	$1.60
DEC	$39.05	$40.00	$1.56	$1.60	$39.05	$40.00	$1.56	$1.60
JAN91	$45.01	$46.25	$1.80	$1.85	$43.07	$44.25	$1.72	$1.77
FEB	$44.87	$46.25	$1.79	$1.85	$42.93	$44.25	$1.72	$1.77
MAR	$44.73	$46.25	$1.79	$1.85	$42.80	$44.25	$1.71	$1.77
APR91	$45.07	$46.75	$1.80	$1.87	$42.90	$44.50	$1.72	$1.78
MAY91	$43.73	$45.50	$1.75	$1.82	$41.33	$43.00	$1.65	$1.72
JUNE	$43.59	$45.50	$1.74	$1.82	$41.20	$43.00	$1.65	$1.72
JULY	$42.26	$44.25	$1.69	$1.77	$39.87	$41.75	$1.59	$1.67
AUG	$39.75	$41.75	$1.59	$1.67	$39.75	$41.75	$1.59	$1.67
SEPT91	$39.15	$41.25	$1.57	$1.65	$38.91	$41.60	$1.56	$1.64
OCT 91	$39.26	$41.50	$1.57	$1.66	$39.02	$41.25	$1.56	$1.65
NOV	$39.14	$41.50	$1.57	$1.66	$38.90	$41.25	$1.56	$1.65
DEC	$39.01	$41.50	$1.56	$1.66	$38.78	$41.25	$1.55	$1.65
JAN 92	$44.73	$47.75	$1.79	$1.91	$42.62	$45.50	$1.70	$1.82
FEB	$44.57	$47.75	$1.78	$1.91	$42.47	$45.50	$1.70	$1.82
MAR	$44.41	$47.75	$1.78	$1.91	$42.32	$45.50	$1.69	$1.82
APR92	$44.71	$48.25	$1.79	$1.93	$42.40	$45.75	$1.70	$1.83
MAY92	$43.40	$47.00	$1.74	$1.88	$40.86	$44.25	$1.63	$1.77
JUN	$43.25	$47.00	$1.73	$1.88	$40.72	$44.25	$1.63	$1.77
JULY	$39.20	$42.75	$1.57	$1.71	$39.65	$43.25	$1.59	$1.73
AUG	$39.51	$43.25	$1.58	$1.73	$39.51	$43.25	$1.58	$1.73
SEPT92	$38.92	$42.75	$1.56	$1.71	$38.69	$42.50	$1.55	$1.70
OCT92	$39.00	$43.00	$1.56	$1.72	$38.70	$42.75	$1.55	$1.71
NOV	$38.07	$43.00	$1.55	$1.72	$38.64	$42.75	$1.55	$1.71
DEC	$38.73	$43.00	$1.55	$1.72	$38.50	$42.75	$1.54	$1.71

APRIL 1990 TO DECEMBER 1994 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR & NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED 1990 DOLLAR & NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON &
PER MMBTU
BASE CASE SCENARIO

APRIL 25, 1990

ST. JOHNS RIVER POWER PARK COAL
(WEIGHTED AVERAGE CONTRACT/SPOT PRICE)

DATE	$/TON 1990$	$/TON NOMINAL	$/MMBTU 1990$	$/MMBTU NOMINAL
JAN93	$44.64	$49.75	$1.79	$1.99
FEB	$44.47	$49.75	$1.78	$1.99
MAR	$44.31	$49.75	$1.77	$1.99
APR93	$44.59	$50.25	$1.78	$2.01
MAY 93	$43.31	$49.00	$1.73	$1.96
JUN	$43.15	$49.00	$1.73	$1.96
JUL	$39.92	$45.50	$1.60	$1.82
AUG	$39.77	$45.50	$1.59	$1.82
SEP93	$38.97	$44.75	$1.56	$1.79
OCT93	$39.26	$45.25	$1.57	$1.81
NOV	$39.11	$45.25	$1.56	$1.81
DEC	$38.97	$45.25	$1.56	$1.81
JAN94	$44.60	$52.00	$1.78	$2.08
FEB	$44.42	$52.00	$1.78	$2.08
MAR	$44.25	$52.00	$1.77	$2.08
APR94	$44.50	$52.50	$1.78	$2.10
MAY 94	$43.26	$51.25	$1.73	$2.05
JUN	$43.09	$51.25	$1.72	$2.05
JUL	$39.99	$47.75	$1.60	$1.91
AUG	$39.83	$47.75	$1.59	$1.91
SEP94	$39.26	$47.25	$1.57	$1.89
OCT94	$39.51	$47.75	$1.58	$1.91
NOV	$39.36	$47.75	$1.57	$1.91
DEC	$39.20	$47.75	$1.57	$1.91

ST. JOHNS RIVER POWER PARK COAL
SPOT COAL PRICE

$/TON 1990$	$/TON NOMINAL	$/MMBTU 1990$	$/MMBTU NOMINAL
$42.04	$47.75	$1.71	$1.91
$42.69	$47.75	$1.71	$1.91
$42.53	$47.75	$1.70	$1.91
$42.59	$48.00	$1.70	$1.92
$41.10	$46.50	$1.64	$1.86
$40.95	$46.50	$1.64	$1.86
$39.92	$45.50	$1.60	$1.82
$39.77	$45.50	$1.59	$1.82
$38.97	$44.75	$1.56	$1.79
$39.04	$45.00	$1.56	$1.80
$38.90	$45.00	$1.56	$1.80
$38.75	$45.00	$1.55	$1.80
$42.89	$50.00	$1.72	$2.00
$42.72	$50.00	$1.71	$2.00
$42.55	$50.00	$1.70	$2.00
$42.59	$50.25	$1.70	$2.01
$41.34	$49.00	$1.65	$1.96
$41.20	$49.00	$1.65	$1.96
$40.20	$48.00	$1.61	$1.92
$40.04	$48.00	$1.60	$1.92
$39.26	$47.25	$1.57	$1.89
$39.31	$47.50	$1.57	$1.90
$39.15	$47.50	$1.57	$1.90
$39.00	$47.50	$1.56	$1.90

1990 TO 2019 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

CONSTANT 1990 DOLLAR & NOMINAL CRUDE OIL & FUEL OIL PRICES

BASE CASE SCENARIO

APRIL 25, 1990

	WORLD CRUDE OIL				DISTILLATE FUEL OIL				1.0% S RESIDUAL FUEL OIL @ US GULF COAST			
	$/BBL		$/MMBTU		$/BBL		$/BBL		$/BBL		$/BBL	
YEAR	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL	1990$	NOMINAL
1990	$17.20	$17.20	$2.95	$2.95	$22.70	$22.70	$3.09	$3.09	$16.00	$16.00	$2.52	$2.52
1991	$18.10	$18.79	$3.10	$3.22	$23.06	$24.73	$4.09	$4.24	$16.87	$17.51	$2.65	$2.75
1992	$20.45	$22.14	$3.51	$3.80	$26.04	$28.98	$4.60	$4.97	$19.10	$20.68	$3.00	$3.25
1993	$22.00	$25.79	$3.91	$4.42	$29.83	$33.62	$5.12	$5.77	$21.34	$24.14	$3.36	$3.80
1994	$25.10	$29.76	$4.31	$5.10	$32.77	$38.67	$5.62	$6.63	$23.54	$27.91	$3.70	$4.39
1995	$27.20	$33.09	$4.67	$5.81	$35.47	$43.95	$6.08	$7.54	$25.57	$31.86	$4.02	$5.01
1996	$29.00	$37.98	$4.97	$6.51	$38.61	$50.30	$6.62	$8.63	$27.84	$36.46	$4.38	$5.73
1997	$30.55	$42.05	$5.24	$7.21	$40.79	$55.87	$7.00	$9.58	$29.45	$40.54	$4.63	$6.37
1998	$31.85	$46.08	$5.46	$7.90	$42.67	$61.43	$7.32	$10.54	$30.83	$44.60	$4.85	$7.01
1999	$32.90	$50.02	$5.64	$8.58	$44.23	$66.94	$7.59	$11.40	$31.98	$48.62	$5.03	$7.65
2000	$33.75	$53.93	$5.79	$9.25	$45.54	$72.46	$7.81	$12.43	$32.94	$52.64	$5.18	$8.28
2001	$34.55	$58.00	$5.93	$9.96	$50.05	$83.00	$8.39	$14.37	$35.45	$59.59	$5.57	$9.37
2002	$35.15	$62.16	$6.03	$10.66	$51.46	$90.65	$8.83	$15.55	$36.35	$64.28	$5.71	$10.11
2003	$35.65	$66.26	$6.11	$11.37	$52.75	$97.66	$9.05	$16.75	$37.15	$69.05	$5.84	$10.86
2004	$36.15	$70.55	$6.20	$12.10	$54.05	$105.09	$9.27	$18.03	$37.96	$74.08	$5.97	$11.65
2005	$36.50	$74.73	$6.26	$12.82	$55.07	$112.33	$9.45	$19.27	$38.58	$78.98	$6.07	$12.42
2006	$36.80	$79.03	$6.31	$13.56	$56.03	$119.89	$9.61	$20.56	$39.16	$84.09	$6.16	$13.22
2007	$37.10	$83.66	$6.36	$14.35	$57.00	$128.07	$9.78	$21.97	$39.73	$89.60	$6.25	$14.09
2008	$37.30	$88.32	$6.40	$15.15	$57.74	$136.24	$9.90	$23.37	$40.17	$95.12	$6.32	$14.96
2009	$37.45	$93.20	$6.42	$15.99	$58.42	$144.88	$10.02	$24.85	$40.56	$100.93	$6.38	$15.87
2010	$37.60	$98.24	$6.45	$16.85	$59.03	$153.70	$10.12	$26.36	$40.91	$106.09	$6.43	$16.81
2011	$37.70	$103.43	$6.47	$17.74	$59.40	$162.64	$10.20	$27.90	$41.17	$112.95	$6.47	$17.76
2012	$37.80	$108.99	$6.48	$18.70	$59.86	$172.03	$10.27	$29.51	$41.39	$119.35	$6.51	$18.77
2013	$37.95	$115.23	$6.51	$19.76	$60.25	$182.32	$10.33	$31.27	$41.63	$126.40	$6.55	$19.87
2014	$38.05	$121.88	$6.53	$20.91	$60.48	$193.09	$10.37	$33.12	$41.78	$133.83	$6.57	$21.04
2015	$38.15	$128.93	$6.54	$22.11	$60.63	$204.24	$10.40	$35.03	$41.89	$141.56	$6.59	$22.26
2016	$38.25	$136.37	$6.56	$23.39	$60.71	$215.76	$10.41	$37.01	$41.96	$149.60	$6.60	$23.52
2017	$38.35	$144.25	$6.58	$24.74	$60.72	$227.63	$10.41	$39.05	$41.99	$157.95	$6.60	$24.84
2018	$38.45	$152.50	$6.60	$26.17	$60.64	$239.85	$10.40	$41.14	$41.99	$166.62	$6.60	$26.20
2019	$38.50	$161.18	$6.60	$27.65	$60.41	$251.90	$10.36	$43.21	$41.89	$175.37	$6.59	$27.57

1990 TO 2019 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D   C O N S T A N T   1 9 9 0   D O L L A R   &   N O M I N A L   D O L L A R   F U E L   O I L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L   &   P E R   M M B T U

B A S E   C A S E   S C E N A R I O

APRIL 25, 1990

YEAR	0.3% SULFUR FUEL OIL $/BBL 1990$	0.3% $/BBL NOMINAL	0.3% $/MMBTU 1990$	0.3% $/MMBTU NOMINAL	0.7% SULFUR FUEL OIL $/BBL 1990$	0.7% $/BBL NOMINAL	0.7% $/MMBTU 1990$	0.7% $/MMBTU NOMINAL
1990	$18.56	$18.56	$2.92	$2.92	$17.93	$17.93	$2.81	$2.81
1991	$19.59	$20.30	$3.08	$3.19	$18.84	$19.52	$2.96	$3.06
1992	$22.12	$23.07	$3.48	$3.75	$21.18	$22.85	$3.32	$3.59
1993	$24.69	$27.00	$3.88	$4.37	$23.33	$26.48	$3.69	$4.16
1994	$27.23	$32.10	$4.28	$5.05	$25.83	$30.44	$4.06	$4.78
1995	$29.61	$36.64	$4.65	$5.76	$27.95	$34.58	$4.39	$5.43
1996	$32.07	$42.78	$5.17	$6.73	$30.33	$39.46	$4.76	$6.20
1997	$34.92	$47.00	$5.49	$7.51	$32.02	$43.80	$5.03	$6.88
1998	$36.74	$52.86	$5.78	$8.31	$33.47	$48.13	$5.25	$7.56
1999	$38.31	$57.94	$6.02	$9.11	$34.68	$52.42	$5.44	$8.23
2000	$39.68	$63.09	$6.24	$9.92	$35.69	$56.70	$5.60	$8.90
2001	$44.84	$75.05	$7.25	$11.80	$38.32	$64.07	$6.02	$10.06
2002	$46.41	$81.71	$7.30	$12.85	$39.26	$69.07	$6.16	$10.84
2003	$47.88	$88.62	$7.53	$13.93	$40.10	$74.16	$6.30	$11.64
2004	$49.30	$95.98	$7.76	$15.09	$40.95	$79.53	$6.43	$12.49
2005	$50.62	$103.22	$7.96	$16.25	$41.61	$84.77	$6.53	$13.31
2006	$51.82	$110.84	$8.15	$17.43	$42.22	$90.23	$6.63	$14.16
2007	$53.03	$119.12	$8.34	$18.73	$42.83	$96.12	$6.72	$15.09
2008	$54.02	$127.44	$8.49	$20.04	$43.29	$102.02	$6.80	$16.02
2009	$54.96	$136.27	$8.64	$21.43	$43.70	$108.24	$6.86	$16.99
2010	$55.81	$145.29	$8.78	$22.85	$44.07	$114.62	$6.92	$17.99
2011	$56.49	$154.44	$8.88	$24.28	$44.35	$121.11	$6.96	$19.01
2012	$57.08	$164.01	$8.97	$25.79	$44.58	$127.98	$7.00	$20.09
2013	$57.64	$174.42	$9.06	$27.42	$44.84	$135.54	$7.04	$21.28
2014	$58.03	$185.26	$9.12	$29.13	$45.00	$143.51	$7.06	$22.53
2015	$58.32	$196.42	$9.17	$30.88	$45.12	$151.80	$7.08	$23.83
2016	$58.50	$207.88	$9.20	$32.69	$45.20	$160.43	$7.10	$25.19
2017	$58.58	$219.61	$9.21	$34.53	$45.24	$169.40	$7.10	$26.59
2018	$58.56	$231.58	$9.21	$36.41	$45.23	$178.71	$7.10	$28.06
2019	$58.35	$243.26	$9.17	$38.25	$45.13	$187.94	$7.09	$29.50

YEAR	1.0% SULFUR FUEL OIL $/BBL 1990$	1.0% $/BBL NOMINAL	1.0% $/MMBTU 1990$	1.0% $/MMBTU NOMINAL	1.5% SULFUR FUEL OIL $/BBL 1990$	1.5% $/BBL NOMINAL	1.5% $/MMBTU 1990$	1.5% $/MMBTU NOMINAL
1990	$17.19	$17.19	$2.70	$2.70	$16.39	$16.39	$2.58	$2.58
1991	$18.67	$18.71	$2.84	$2.94	$17.29	$17.82	$2.71	$2.81
1992	$20.30	$21.89	$3.19	$3.44	$19.29	$20.88	$3.04	$3.28
1993	$22.54	$25.36	$3.54	$3.99	$21.39	$24.97	$3.37	$3.79
1994	$24.74	$29.14	$3.89	$4.58	$23.45	$27.61	$3.69	$4.35
1995	$26.77	$33.18	$4.21	$5.20	$25.33	$31.31	$3.99	$4.93
1996	$29.04	$37.77	$4.57	$5.94	$26.86	$34.92	$4.23	$5.50
1997	$30.65	$41.91	$4.82	$6.59	$28.34	$38.73	$4.46	$6.10
1998	$32.03	$46.04	$5.04	$7.24	$29.59	$42.52	$4.66	$6.70
1999	$33.18	$50.14	$5.22	$7.88	$30.63	$46.26	$4.82	$7.29
2000	$34.14	$54.23	$5.37	$8.53	$31.49	$50.00	$4.96	$7.87
2001	$36.63	$61.27	$5.76	$9.63	$31.92	$53.32	$5.03	$8.40
2002	$37.54	$66.04	$5.90	$10.38	$32.70	$57.48	$5.15	$9.05
2003	$38.34	$70.89	$6.03	$11.15	$33.40	$61.70	$5.26	$9.72
2004	$39.15	$76.02	$6.16	$11.95	$34.10	$66.15	$5.37	$10.4[illegible]
2005	$39.78	$81.02	$6.25	$12.74	$34.62	$70.67	$5.45	$11.10
2006	$40.35	$86.23	$6.34	$13.56	$35.10	$74.95	$5.53	$11.88
2007	$40.93	$91.84	$6.44	$14.44	$35.59	$79.79	$5.60	$12.56
2008	$41.37	$97.47	$6.50	$15.33	$35.94	$84.61	$5.66	$13.32
2009	$41.76	$103.41	$6.57	$16.26	$36.24	$89.69	$5.71	$14.12
2010	$42.11	$109.49	$6.62	$17.22	$36.51	$94.88	$5.75	$14.96
2011	$42.37	$115.68	$6.66	$18.19	$36.70	$100.14	$5.78	$15.77
2012	$42.59	$122.22	$6.70	$19.22	$36.85	$105.69	$5.80	$16.64
2013	$42.83	$129.44	$6.73	$20.35	$37.02	$111.81	$5.83	$17.61
2014	$42.98	$137.03	$6.76	$21.55	$37.11	$118.23	$5.84	$18.62
2015	$43.09	$144.99	$6.77	$22.79	$37.16	$124.90	$5.85	$19.67
2016	$43.16	$153.16	$6.79	$24.08	$37.17	$131.82	$5.85	$20.76
2017	$43.19	$161.71	$6.79	$25.43	$37.15	$138.99	$5.85	$21.89
2018	$43.18	$170.58	$6.79	$26.82	$37.10	$146.42	$5.84	$23.06
2019	$43.09	$179.37	$6.77	$28.20	$36.96	$153.71	$5.82	$24.21

$$\frac{\$}{MMBTU} \times 9700\,\frac{BTU}{KWH} \times \frac{1000\,K}{M} \times \frac{MM}{1{,}000{,}000}$$

1990 TO 2019 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

DELIVERED CONSTANT 1990 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU & NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

APRIL 25, 1990

BASE CASE SCENARIO

YEAR	INTERRUPTIBLE SERVICE: P10 GAS $/MMBTU 1990$	P10 GAS NOMINAL	INTERRUPTIBLE SERVICE: SPOT GAS $/MMBTU 1990$	SPOT GAS NOMINAL	FIRM SERVICE: SPOT GAS $/MMBTU 1990$	SPOT GAS NOMINAL	FIRM SERVICE: AMOCO/CITRUS GAS $/MMBTU 1990$	AMOCO/CITRUS GAS NOMINAL	AVERAGE GAS PRICE $/MMBTU 1990$	AVERAGE GAS PRICE NOMINAL	NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY: INTERRUPTIBLE SERVICE P10	INTERRUPTIBLE SERVICE SPOT	FIRM SERVICE SPOT	FIRM SERVICE FIRM	TOTAL	MEMO: SPOT/MARKET GAS @ USGC $/MMBTU 1990$	MEMO NOMINAL	TRANSPORTATION SERVICE INTERRUPTIBLE $/MMBTU 1990$	INTERRUPTIBLE NOMINAL	TRANSPORTATION SERVICE FIRM $/MMBTU 1990$	FIRM NOMINAL
1990	$2.41	$2.41	$2.14	$2.14	$2.20	$2.20	$2.54	$2.54	$2.40	$2.40	86	86	19	178	369	$1.01	$1.01	$0.33	$0.33	$0.38	$0.38
1991	$2.54	$2.64	$2.34	$2.43	$2.40	$2.49	$2.68	$2.78	$2.62	$2.72	24	24	31	282	361	$2.02	$2.09	$0.32	$0.34	$0.38	$0.40
1992	$2.88	$3.12	$2.69	$2.92	$2.75	$2.98	$2.92	$3.16	$2.88	$3.11	47	47	33	299	426	$2.37	$2.57	$0.32	$0.35	$0.38	$0.41
1993	$3.22	$3.64	$3.04	$3.44	$3.10	$3.51	$3.24	$3.66	$3.21	$3.63	30	30	33	279	392	$2.72	$3.07	$0.32	$0.37	$0.38	$0.43
1994	$3.55	$4.21	$3.36	$3.99	$3.42	$4.05	$3.54	$4.20	$3.52	$4.17	32	32	33	299	396	$3.04	$3.60	$0.33	$0.39	$0.38	$0.46
1995	$3.86	$4.88	$3.64	$4.54	$3.70	$4.61	$3.82	$4.77	$3.80	$4.74	23	23	33	299	377	$3.32	$4.13	$0.33	$0.41	$0.38	$0.48
1996	$4.20	$5.50	$4.07	$5.33	$4.13	$5.41	$4.16	$5.45	$4.15	$5.44	27	27	33	299	385	$3.74	$4.90	$0.33	$0.43	$0.39	$0.51
1997	$4.44	$6.11	$4.34	$5.97	$4.39	$6.04	$4.37	$6.01	$4.37	$6.02	32	32	0	332	395	$4.01	$5.51	$0.33	$0.46	$0.39	$0.53
1998	$4.65	$6.73	$4.57	$6.62	$4.63	$6.69	$4.51	$6.53	$4.53	$6.55	34	34	0	332	399	$4.24	$6.14	$0.33	$0.48	$0.38	$0.56
1999	$4.82	$7.33	$4.78	$7.27	$4.83	$7.35	$4.55	$6.92	$4.59	$6.98	35	35	0	332	401	$4.45	$6.77	$0.33	$0.51	$0.38	$0.58
2000	$4.97	$7.94	$4.97	$7.94					$4.97	$7.94	203	203			406	$4.64	$7.41	$0.33	$0.53	$0.38	$0.61
2001	$5.35	$8.99	$5.71	$9.60					$5.71	$9.60	0	398			398	$5.30	$9.04	$0.33	$0.56	$0.39	$0.65
2002	$5.48	$9.69	$5.91	$10.45					$5.91	$10.45	0	398			398	$5.57	$9.85	$0.34	$0.60	$0.38	$0.68
2003	$5.60	$10.41	$6.09	$11.32					$6.09	$11.32	0	397			397	$5.75	$10.69	$0.34	$0.63	$0.38	$0.71
2004			$6.27	$12.25					$6.27	$12.25		397			397	$5.94	$11.59	$0.34	$0.66	$0.38	$0.74
2005			$6.43	$13.17					$6.43	$13.17		404			404	$6.10	$12.48	$0.34	$0.69	$0.38	$0.78
2006			$6.60	$14.17					$6.60	$14.17		396			396	$6.26	$13.45	$0.34	$0.72	$0.38	$0.91
2007			$6.76	$15.25					$6.76	$15.25		405			405	$6.43	$14.50	$0.33	$0.75	$0.38	$0.85
2008			$6.92	$16.37					$6.92	$16.37		405			405	$6.58	$15.50	$0.33	$0.79	$0.38	$0.89
2009			$7.07	$17.59					$7.07	$17.59		405			405	$6.73	$16.76	$0.33	$0.83	$0.37	$0.93
2010			$7.22	$18.87					$7.22	$18.87		405			405	$6.89	$18.00	$0.33	$0.87	$0.37	$0.97
2011			$7.36	$20.19					$7.36	$20.19		405			405	$7.03	$19.29	$0.33	$0.91	$0.37	$1.02
2012			$7.51	$21.67					$7.51	$21.67		405			405	$7.18	$20.72	$0.33	$0.95	$0.37	$1.06
2013			$7.67	$23.30					$7.67	$23.30		405			405	$7.34	$22.30	$0.33	$1.00	$0.37	$1.12
2014			$7.82	$25.06					$7.82	$25.06		405			405	$7.50	$24.01	$0.33	$1.05	$0.37	$1.17
2015			$7.97	$26.92					$7.97	$26.92		405			405	$7.64	$25.82	$0.33	$1.10	$0.36	$1.23
2016			$8.11	$28.92					$8.11	$28.92		405			405	$7.79	$27.76	$0.33	$1.16	$0.36	$1.29
2017			$8.25	$31.02					$8.25	$31.02		405			405	$7.92	$29.80	$0.32	$1.22	$0.36	$1.36
2018			$8.38	$33.24					$8.38	$33.24		405			405	$8.05	$31.96	$0.32	$1.28	$0.36	$1.42
2019			$8.49	$35.54					$8.49	$35.54		405			405	$8.17	$34.19	$0.32	$1.35	$0.36	$1.49

1990 TO 2019 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1990 DOLLAR AND NOMINAL DOLLAR PRICES APPROVED BY THE FORECAST REVIEW BOARD ON APRIL 25, 1990

D E L I V E R E D C O N S T A N T 1 9 9 0 D O L L A R & N O M I N A L D O L L A R C O A L P R I C E S I N D O L L A R S P E R T O N & P E R M M B T U

B A S E C A S E S C E N A R I O

APRIL 25, 1990
A

C O A L D E L I V E R I E S T O M A R T I N A S S U M E S C O M P E T I T I O N B E T W E E N 2 M O D E S O F T R A N S P O R T

YEAR	ST. JOHNS RIVER POWER PARK (WEIGHTED AVERAGE PRICE) $/TON 1990$	NOMINAL	$/MMBTU 1990$	NOMINAL	ST. JOHNS RIVER POWER PARK (SPOT/SHORT-TERM CONTRACT PRICE) $/TON 1990$	NOMINAL	$/MMBTU 1990$	NOMINAL	HIGH SULFUR COAL TO MARTIN $/TON 1990$	NOMINAL	$/MMBTU 1990$	NOMINAL	MEDIUM SULFUR COAL TO MARTIN $/TON 1990$	NOMINAL	$/MMBTU 1990$	NOMINAL	LOW SULFUR COAL TO MARTIN $/TON 1990$	NOMINAL	$/MMBTU 1990$	NOMINAL
1990	$43.50	$43.50	$1.74	$1.74	$40.50	$40.50	$1.62	$1.62	$44.53	$44.53	$1.71	$1.71	$43.55	$43.55	$1.74	$1.74	$47.19	$47.19	$1.97	$1.97
1991	$43.35	$45.00	$1.73	$1.80	$39.90	$41.50	$1.60	$1.66	$43.65	$45.31	$1.68	$1.74	$42.74	$44.36	$1.71	$1.77	$46.33	$48.10	$1.93	$2.00
1992	$40.18	$43.50	$1.61	$1.74	$39.72	$43.00	$1.59	$1.72	$43.19	$46.76	$1.66	$1.80	$42.22	$45.71	$1.69	$1.83	$46.12	$49.93	$1.92	$2.08
1993	$40.00	$45.25	$1.60	$1.83	$40.00	$45.25	$1.60	$1.81	$43.63	$49.14	$1.67	$1.89	$42.22	$47.76	$1.69	$1.91	$46.61	$52.73	$1.94	$2.20
1994	$40.27	$47.75	$1.61	$1.91	$40.06	$47.50	$1.60	$1.90	$43.39	$51.60	$1.68	$1.99	$42.58	$50.48	$1.70	$2.02	$47.01	$55.74	$1.96	$2.32
1995	$40.53	$50.50	$1.62	$2.02	$40.12	$50.00	$1.60	$2.00	$44.22	$55.10	$1.70	$2.12	$43.20	$53.83	$1.73	$2.15	$47.86	$59.65	$1.99	$2.49
1996	$40.05	$53.50	$1.63	$2.14	$40.47	$53.00	$1.62	$2.12	$44.55	$58.34	$1.71	$2.24	$43.61	$57.12	$1.74	$2.28	$48.72	$63.80	$2.03	$2.66
1997	$41.05	$56.50	$1.64	$2.26	$40.60	$56.00	$1.63	$2.24	$45.00	$61.94	$1.73	$2.38	$44.14	$60.75	$1.77	$2.43	$50.05	$68.09	$2.09	$2.87
1998	$41.30	$59.75	$1.65	$2.39	$40.70	$59.00	$1.63	$2.36	$45.45	$65.75	$1.75	$2.53	$44.66	$64.61	$1.79	$2.58	$51.15	$73.99	$2.13	$3.08
1999	$41.44	$63.00	$1.66	$2.52	$40.78	$62.00	$1.63	$2.48	$45.64	$69.39	$1.76	$2.67	$45.44	$69.09	$1.82	$2.76	$52.40	$79.80	$2.19	$3.32
2000	$41.93	$67.00	$1.68	$2.68	$40.99	$65.50	$1.64	$2.62	$46.08	$73.64	$1.77	$2.83	$45.97	$73.46	$1.84	$2.94	$53.83	$86.01	$2.24	$3.58
2001	$41.64	$70.00	$1.67	$2.80	$40.00	$67.25	$1.60	$2.69	$45.43	$76.41	$1.75	$2.96	$45.85	$77.08	$1.83	$3.08	$56.67	$95.27	$2.36	$3.97
2002	$41.00	$72.50	$1.64	$2.90	$40.43	$71.50	$1.62	$2.86	$45.92	$81.21	$1.77	$3.12	$46.58	$82.37	$1.86	$3.29	$57.41	$101.52	$2.39	$4.23
2003	$41.43	$77.00	$1.66	$3.08	$40.09	$76.00	$1.64	$3.04	$46.04	$87.06	$1.80	$3.35	$47.71	$88.69	$1.91	$3.55	$58.56	$100.04	$2.46	$4.54
2004	$41.76	$81.50	$1.67	$3.26	$41.12	$80.25	$1.64	$3.21	$47.40	$92.51	$1.82	$3.56	$48.49	$94.63	$1.94	$3.79	$59.32	$115.78	$2.47	$4.82
2005	$42.13	$86.25	$1.69	$3.45	$41.32	$85.00	$1.66	$3.40	$48.24	$98.75	$1.86	$3.80	$49.56	$101.46	$1.98	$4.06	$60.41	$123.67	$2.52	$5.15
2006	$42.61	$91.50	$1.70	$3.66	$42.02	$90.25	$1.68	$3.61	$49.23	$105.99	$1.90	$4.08	$50.99	$109.30	$2.04	$4.37	$61.75	$132.61	$2.57	$5.53
2007	$43.13	$97.25	$1.73	$3.89	$42.46	$95.75	$1.70	$3.83	$50.19	$113.18	$1.93	$4.35	$51.98	$117.21	$2.08	$4.69	$62.84	$141.69	$2.62	$5.90
2008	$43.50	$103.00	$1.74	$4.12	$42.87	$101.50	$1.71	$4.06	$51.03	$120.83	$1.96	$4.65	$53.06	$125.64	$2.12	$5.03	$63.93	$151.36	$2.66	$6.31
2009	$43.90	$109.25	$1.76	$4.37	$43.30	$107.75	$1.73	$4.31	$51.87	$129.07	$1.99	$4.96	$54.15	$134.76	$2.17	$5.39	$65.02	$161.80	$2.71	$6.74
2010	$44.09	$116.25	$1.78	$4.65	$44.01	$115.00	$1.76	$4.60	$53.27	$139.10	$2.05	$5.35	$55.82	$145.04	$2.23	$5.83	$66.70	$174.28	$2.78	$7.26
2011	$45.01	$123.50	$1.80	$4.94	$44.56	$122.25	$1.78	$4.89	$54.10	$148.43	$2.08	$5.71	$56.91	$156.13	$2.28	$6.25	$67.80	$186.80	$2.82	$7.75
2012	$45.43	$131.00	$1.82	$5.24	$44.91	$129.50	$1.80	$5.18	$55.22	$159.23	$2.12	$6.12	$58.28	$168.06	$2.33	$6.72	$69.16	$199.41	$2.88	$8.31
2013	$45.86	$139.25	$1.83	$5.57	$45.62	$138.50	$1.82	$5.54	$56.34	$171.06	$2.17	$6.58	$59.70	$181.26	$2.39	$7.23	$70.59	$214.34	$2.94	$8.93
2014	$46.28	$148.25	$1.85	$5.93	$45.81	$146.75	$1.83	$5.87	$57.46	$184.04	$2.21	$7.08	$61.00	$195.63	$2.44	$7.83	$71.96	$230.49	$3.00	$9.60
2015	$47.30	$160.00	$1.89	$6.40	$46.60	$157.75	$1.87	$6.31	$58.05	$198.09	$2.26	$7.65	$62.77	$212.13	$2.51	$8.49	$73.66	$248.94	$3.07	$10.37
2016	$47.54	$169.50	$1.90	$6.78	$46.91	$167.25	$1.88	$6.69	$59.97	$213.01	$2.31	$8.22	$64.16	$228.75	$2.57	$9.15	$75.03	$267.30	$3.13	$11.15
2017	$48.19	$181.25	$1.93	$7.25	$47.46	$178.50	$1.90	$7.14	$61.37	$230.82	$2.36	$8.88	$65.87	$247.75	$2.63	$9.91	$76.74	$288.67	$3.20	$12.03
2018	$48.45	$192.25	$1.94	$7.69	$47.94	$190.25	$1.92	$7.61	$62.59	$248.36	$2.41	$9.55	$67.40	$267.46	$2.70	$10.70	$78.20	$310.65	$3.26	$12.94
2019	$48.79	$204.25	$1.95	$8.17	$48.31	$202.25	$1.93	$8.09	$63.96	$267.77	$2.46	$10.30	$69.00	$288.07	$2.76	$11.55	$80.16	$335.99	$3.34	$13.98

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Inter-Office Correspondence

FPL

To: **Distribution**

Date: **April 8, 1991**

From: **C. O. Woody**

Department: **JEX/JB**

Subject: **Short and Long-Term Fossil Fuel Price and Natural Gas Availability Forecast**

Attached are the short and long-term fossil fuel price forecasts for crude oil, residual and distillate fuel oil, natural gas, and coal, as well as the projection for natural gas availability to be used for FPL planning purposes until superseded.

Questions concerning these forecasts or any underlying assumption should be directed to Eugene Ungar on extension 3412 in the General Office.

C.O. Woody
Executive Vice President
Chairman, Delivery Committee

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FTT-91-3
Attachments

Form 1008 (Stocked) Rev. 2/89

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APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

APRIL 5, 1991

DATE	**********CRUDE OIL********** ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	WTI FIRST FORWARD MONTH FUTURE'S PRICE	*******DISTILLATE FUEL OIL************ EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
APR91	$15.80	$17.30		$18.96	$19.17	$18.85	$19.49
MAY91	$15.45	$16.95		$18.34	$18.55	$18.23	$18.88
JUNE	$15.75	$17.25	$18.75	$18.61	$18.82	$18.50	$19.15
JULY	$18.20	$19.70	$21.20	$21.92	$22.13	$21.81	$22.46
AUG	$18.95	$20.45	$21.95	$22.83	$23.04	$22.72	$23.37
SEP191	$18.75	$20.25	$21.75	$23.12	$23.33	$23.01	$23.65
OCT 91	$19.61	$21.11	$22.61	$24.31	$24.52	$24.20	$24.84
NOV	$20.67	$22.17	$23.67	$25.24	$25.45	$25.13	$25.78
DEC	$21.74	$23.24	$24.74	$26.81	$27.02	$26.70	$27.35
JAN 92	$22.50	$24.00	$25.50	$29.70	$29.91	$29.58	$30.24
FEB	$22.00	$23.50	$25.00	$29.07	$29.28	$28.95	$29.61
MAR	$21.25	$22.75	$24.25	$27.69	$27.90	$27.57	$28.23
APR92	$20.18	$21.68	$23.18	$26.44	$26.65	$26.33	$26.98
MAY92	$19.42	$20.92	$22.42	$25.15	$25.36	$25.03	$25.69
JUN	$20.59	$22.09	$23.59	$26.54	$26.76	$26.43	$27.09
JULY	$21.72	$23.22	$24.72	$28.25	$28.47	$28.14	$28.80
AUG	$22.09	$23.59	$25.09	$28.76	$28.98	$28.65	$29.31
SEP192	$21.58	$23.08	$24.58	$28.72	$28.94	$28.61	$29.28
OCT92	$21.89	$23.39	$24.89	$29.43	$29.64	$29.31	$29.98
NOV	$23.09	$24.59	$26.09	$30.62	$30.84	$30.50	$31.17
DEC	$24.24	$25.74	$27.24	$32.45	$32.66	$32.33	$33.00

DATE	*0.7% RESIDUAL* MARTIN	****************1.0% SULFUR RESIDUAL FUEL OIL************************************* PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	*******1.5% RESIDUAL******* CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
APR91	$13.62	$13.74	$13.25	$13.00	$12.76	$13.49	$12.69	$13.08	$14.01	$12.91	$12.38	$13.15	$11.90	$11.80
MAY91	$13.65	$13.77	$13.27	$13.00	$12.79	$13.52	$12.72	$13.11	$14.04	$12.94	$12.41	$13.18	$11.95	$11.80
JUNE	$14.17	$14.29	$13.77	$13.50	$13.29	$14.02	$13.22	$13.61	$14.54	$13.44	$12.91	$13.67	$12.43	$12.30
JULY	$16.80	$16.91	$16.28	$16.00	$15.80	$16.53	$15.73	$16.11	$17.04	$15.94	$15.41	$16.18	$14.93	$14.80
AUG	$17.81	$17.93	$17.25	$17.00	$16.77	$17.50	$16.70	$17.08	$18.02	$16.91	$16.38	$17.15	$15.90	$15.80
SEP91	$17.31	$17.43	$16.77	$16.50	$16.29	$17.02	$16.22	$16.61	$17.54	$16.43	$15.91	$16.67	$15.42	$15.30
OCT91	$18.32	$18.44	$17.73	$17.48	$17.25	$17.98	$17.18	$17.57	$18.50	$17.40	$16.87	$17.64	$16.38	$16.27
NOV	$19.89	$20.01	$19.24	$18.98	$18.75	$19.49	$18.68	$19.07	$20.01	$18.90	$18.37	$19.14	$17.88	$17.78
DEC	$21.54	$21.65	$20.81	$20.55	$20.33	$21.06	$20.25	$20.64	$21.58	$20.47	$19.94	$20.71	$19.45	$19.35
JAN92	$23.46	$23.58	$22.65	$22.39	$22.17	$22.90	$22.09	$22.49	$23.43	$22.31	$21.64	$22.41	$21.15	$21.19
FEB	$22.97	$23.09	$22.18	$21.92	$21.70	$22.44	$21.62	$22.02	$22.96	$21.84	$21.17	$21.94	$20.68	$20.72
MAR	$21.90	$22.01	$21.15	$20.89	$20.67	$21.41	$20.59	$20.99	$21.93	$20.81	$20.14	$20.91	$19.65	$19.69
APR92	$20.92	$21.04	$20.22	$19.96	$19.73	$20.48	$19.66	$20.06	$21.01	$19.88	$19.20	$19.98	$18.71	$18.76
MAY92	$19.91	$20.03	$19.26	$19.00	$18.77	$19.51	$18.70	$19.09	$20.04	$18.92	$18.24	$19.02	$17.74	$17.79
JUN	$21.00	$21.12	$20.30	$20.04	$19.81	$20.55	$19.74	$20.13	$21.09	$19.96	$19.27	$20.06	$18.78	$18.83
JULY	$22.34	$22.46	$21.58	$21.32	$21.09	$21.84	$21.01	$21.41	$22.37	$21.24	$20.55	$21.34	$20.06	$20.11
AUG	$22.74	$22.86	$21.96	$21.70	$21.47	$22.22	$21.39	$21.79	$22.75	$21.61	$20.93	$21.72	$20.43	$20.49
SEP92	$22.71	$22.83	$21.93	$21.67	[illegible]	$22.19	$21.36	$21.76	$22.72	$21.59	$20.90	$21.69	$20.40	$20.46
OCT92	$23.26	$23.38	$22.46	$22.19	$21.96	$22.71	$21.89	$22.29	$23.25	$22.11	$21.42	$22.21	$20.92	$20.98
NOV	$24.19	$24.31	$23.35	$23.08	$22.85	$23.60	$22.77	$23.18	$24.14	$23.00	$22.31	$23.10	$21.81	$21.87
DEC	$25.61	$25.74	$24.71	$24.45	$24.21	$24.97	$24.14	$24.54	$25.51	$24.36	$23.67	$24.47	$23.17	$23.24

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

APRIL 5, 1991

DATE	**********CRUDE OIL**********			*******DISTILLATE FUEL OIL***************			
	ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	WTI FIRST FORWARD MONTH FUTURE'S PRICE	EVERGLADES	LAUDERDALE	FT MYER	PUTNAM
JAN93	$25.71	$27.21	$28.71	$33.80	$34.02	$33.69	$34.36
FEB	$25.25	$26.75	$28.25	$33.23	$33.44	$33.11	$33.78
MAR	$24.68	$25.98	$27.48	$31.75	$31.97	$31.64	$32.31
APR93	$23.38	$24.88	$26.38	$30.48	$30.70	$30.37	$31.04
MAY 93	$22.60	$24.10	$25.60	$29.11	$29.33	$28.99	$29.67
JUN	$23.82	$25.32	$26.82	$30.55	$30.77	$30.43	$31.11
JUL	$24.99	$26.49	$27.99	$32.36	$32.58	$32.24	$32.93
AUG	$25.31	$26.81	$28.31	$32.83	$33.05	$32.71	$33.40
SEP93	$24.85	$26.35	$27.85	$32.94	$33.16	$32.82	$33.50
OCT93	$25.17	$26.67	$28.17	$33.70	$33.93	$33.58	$34.27
NOV	$26.36	$27.86	$29.36	$34.83	$35.05	$34.71	$35.40
DEC	$27.61	$29.11	$30.61	$36.83	$37.05	$36.71	$37.40
JAN94	$29.07	$30.57	$32.07	$38.12	$38.35	$38.00	$38.70
FEB	$28.55	$30.05	$31.55	$37.45	$37.68	$37.34	$38.03
MAR	$27.75	$29.25	$30.75	$35.09	$36.12	$35.77	$36.47
APR94	$26.68	$28.18	$29.68	$34.66	$34.89	$34.54	$35.24
MAY 94	$25.88	$27.38	$28.88	$33.20	$33.43	$33.08	$33.78
JUN	$27.08	$28.58	$30.08	$34.62	$34.84	$34.50	$35.20
JUL	$28.35	$29.85	$31.35	$36.60	$36.83	$36.48	$37.18
AUG	$28.69	$30.19	$31.69	$37.09	$37.32	$36.97	$37.68
SEP94	$28.16	$29.66	$31.16	$37.21	$37.44	$37.09	$37.80
OCT94	$28.55	$30.05	$31.55	$38.12	$38.35	$37.99	$38.70
NOV	$29.78	$31.28	$32.78	$39.25	$39.48	$39.13	$39.84
DEC	$31.06	$32.56	$34.06	$41.35	$41.58	$41.23	$41.96
JAN95	$32.31	$33.81	$35.31	$41.70	$41.93	$41.58	$42.29
FEB	$31.79	$33.29	$34.79	$40.49	$40.73	$40.37	$41.09
MAR	$30.99	$32.49	$33.99	$39.43	$39.67	$39.31	$40.03
APR95	$29.91	$31.41	$32.91	$38.55	$38.79	$38.43	$39.15
MAY 95	$29.10	$30.60	$32.10	$37.62	$37.85	$37.49	$38.22
JUN	$30.36	$31.86	$33.36	$40.03	$40.27	$39.91	$40.63
JUL	$31.68	$33.18	$34.68	$42.16	$42.39	$42.03	$42.76
AUG	$32.06	$33.56	$35.06	$42.15	$42.39	$42.03	$42.76
SEP95	$31.52	$33.02	$34.52	$41.95	$42.19	$41.83	$42.56
OCT95	$31.95	$33.45	$34.95	$42.51	$42.74	$42.38	$43.11
NOV	$33.30	$34.80	$36.30	$43.73	$43.97	$43.61	$44.34
DEC	$34.70	$36.20	$37.70	$46.05	$46.29	$45.92	$46.66

DATE	**0.7% RESIDUAL**		****************1.0% SULFUR RESIDUAL FUEL OIL************************************								*******1.5% RESIDUAL*******			MEMO: 1% SULFUR RESIDUAL FUEL OIL
	MARTIN	PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERD/LE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	CANAVERAL	SANFORD	FT MYERS	@ USGC
JAN93	$26.64	$26.76	$25.69	$25.42	$25.19	$25.95	$25.11	$25.52	$26.49	$25.34	$24.69	$25.29	$23.99	$24.21
FEB	$26.19	$26.31	$25.26	$24.99	$24.75	$25.52	$24.68	$25.08	$26.06	$24.91	$24.06	$24.86	$23.56	$23.78
MAR	$25.04	$25.16	$24.16	$23.89	$23.66	$24.42	$23.58	$23.99	$24.97	$23.81	$22.96	$23.76	$22.46	$22.68
APR93	$24.05	$24.17	$23.21	$22.94	$22.71	$23.47	$22.63	$23.04	$24.02	$22.86	$22.01	$22.81	$21.50	$21.73
MAY93	$22.97	$23.10	$22.19	$21.92	$21.68	$22.45	$21.61	$22.02	$23.00	$21.84	$20.98	$21.79	$20.48	$20.71
JUN	$24.10	$24.22	$23.26	$22.99	$22.75	$23.52	$22.68	$23.09	$24.07	$22.91	$22.05	$22.86	$21.54	$21.78
JUL	$25.51	$25.63	$24.62	$24.34	$24.11	$24.88	$24.03	$24.44	$25.43	$24.26	$23.40	$24.21	$22.89	$23.13
AUG	$25.88	$26.00	$24.97	$24.70	$24.46	$25.23	$24.38	$24.79	$25.78	$24.61	$23.75	$24.56	$23.24	$23.48
SEP93	$25.96	$26.08	$25.05	$24.77	$24.53	$25.31	$24.46	$24.87	$25.86	$24.69	$23.83	$24.64	$23.31	$23.56
OCT93	$26.56	$26.68	$25.62	$25.34	$25.10	$25.88	$25.03	$25.44	$26.44	$25.26	$24.39	$25.21	$23.88	$24.13
NOV	$27.44	$27.56	$26.46	$26.18	$25.94	$26.72	$25.87	$26.28	$27.28	$26.10	$25.23	$26.05	$24.72	$24.97
DEC	$29.00	$29.12	$27.95	$27.67	$27.43	$28.21	$27.36	$27.77	$28.77	$27.59	$26.72	$27.54	$26.21	$26.46
JAN94	$30.02	$30.15	$28.93	$28.65	$28.41	$29.19	$28.33	$28.75	$29.75	$28.57	$27.54	$28.36	$27.02	$27.44
FEB	$29.50	$29.63	$28.43	$28.15	$27.91	$28.70	$27.84	$28.25	$29.26	$28.07	$27.04	$27.87	$26.52	$26.94
MAR	$28.28	$28.41	$27.27	$26.99	$26.75	$27.53	$26.67	$27.09	$28.09	$26.90	$25.87	$26.70	$25.35	$25.77
APR94	$27.32	$27.45	$26.35	$26.07	$25.83	$26.62	$25.75	$26.17	$27.18	$25.98	$24.95	$25.78	$24.43	$24.85
MAY94	$26.18	$26.31	$25.26	$24.98	$24.74	$25.53	$24.66	$25.08	$26.09	$24.90	$23.86	$24.69	$23.34	$23.76
JUN	$27.29	$27.42	$26.32	$26.04	$25.79	$26.59	$25.72	$26.14	$27.15	$25.95	$24.91	$25.75	$24.39	$24.82
JUL	$28.84	$28.96	$27.80	$27.52	$27.27	$28.07	$27.19	$27.62	$28.63	$27.43	$26.39	$27.22	$25.86	$26.30
AUG	$29.22	$29.35	$28.17	$27.89	$27.64	$28.44	$27.56	$27.99	$29.00	$27.80	$26.76	$27.59	$26.23	$26.67
SEP94	$29.31	$29.44	$28.26	$27.97	$27.73	$[illegible].53	$27.65	$28.07	$29.09	$27.89	$26.84	$27.68	$26.31	$26.75
OCT94	$30.02	$30.15	$28.93	$28.65	$28.40	$29.20	$28.32	$28.75	$29.77	$28.56	$27.51	$28.35	$26.98	$27.43
NOV	$30.91	$31.03	$29.78	$29.49	$29.25	$30.05	$29.17	$29.59	$30.62	$29.41	$28.35	$29.20	$27.83	$28.27
DEC	$32.54	$32.67	$31.34	$31.06	$30.81	$31.62	$30.73	$31.16	$32.19	$30.97	$29.92	$30.76	$29.39	$29.84
JAN95	$32.82	$32.95	$31.60	$31.32	$31.07	$31.88	$30.99	$31.42	$32.45	$31.23	$30.18	$31.02	$29.64	$30.10
FEB	$31.88	$32.01	$30.71	$30.42	$30.17	$30.98	$30.09	$30.52	$31.56	$30.33	$29.27	$30.12	$28.74	$29.20
MAR	$31.05	$31.18	$29.91	$29.63	$29.38	$30.19	$29.30	$29.73	$30.77	$29.54	$28.48	$29.33	$27.96	$28.40
APR95	$30.36	$30.49	$29.26	$28.97	$28.72	$29.53	$28.64	$29.07	$30.11	$28.88	$27.82	$28.67	$27.28	$27.75
MAY95	$29.63	$29.76	$28.56	$28.27	$28.02	$28.84	$27.94	$28.38	$29.42	$28.19	$27.12	$27.97	$26.58	$27.05
JUN	$31.51	$31.65	$30.36	$30.07	$29.82	$30.64	$29.74	$30.18	$31.22	$29.98	$28.91	$29.77	$28.37	$28.85
JUL	$33.17	$33.30	$31.95	$31.66	$31.41	$32.23	$31.33	$31.76	$32.81	$31.57	$30.49	$31.36	$29.95	$30.43
AUG	$33.17	$33.30	$31.95	$31.66	$31.40	$32.22	$31.32	$31.76	$32.81	$31.57	$30.49	$31.35	$29.95	$30.43
SEP95	$33.01	$33.15	$31.80	$31.51	$31.25	$32.08	$31.17	$31.61	$32.66	$31.42	$30.34	$31.20	$[illegible].79	$30.28
OCT95	$33.45	$33.58	$32.21	$31.92	$31.67	$32.49	$31.58	$32.02	$33.08	$31.83	$30.75	$31.62	$30.20	$30.6[illegible]
NOV	$34.41	$34.54	$33.13	$32.84	$32.58	$33.41	$32.50	$32.94	$34.00	$32.74	$31.66	$32.53	$31.11	$31.61
DEC	$36.21	$36.35	$34.86	$34.56	$34.31	$35.14	$34.22	$34.67	$35.73	$34.47	$33.38	$34.26	$32.83	$33.33

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

MEMO:

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   M M B T U

APRIL 5, 1991

DATE	CRUDE OIL: ARABIAN LIGHT PRICE	CRUDE OIL: U.S. REFINER'S ACQUISITION COST	DISTILLATE FUEL OIL: EVERGLADES	DISTILLATE FUEL OIL: LAUDERDALE	DISTILLATE FUEL OIL: FT MYERS	DISTILLATE FUEL OIL: PUTNAM
APR91	$2.71	$2.97	$3.25	$3.29	$3.23	$3.34
MAY91	$2.65	$2.91	$3.15	$3.18	$3.13	$3.24
JUNE	$2.70	$2.96	$3.19	$3.23	$3.17	$3.28
JULY	$3.12	$3.38	$3.76	$3.80	$3.74	$3.85
AUG	$3.25	$3.51	$3.92	$3.95	$3.90	$4.01
SEP191	$3.22	$3.47	$3.97	$4.00	$3.95	$4.06
OCT 91	$3.36	$3.62	$4.17	$4.21	$4.15	$4.26
NOV	$3.55	$3.80	$4.33	$4.37	$4.31	$4.42
DEC	$3.73	$3.99	$4.60	$4.63	$4.58	$4.69
JAN 92	$3.86	$4.12	$5.09	$5.13	$5.07	$5.19
FEB	$3.77	$4.03	$4.99	$5.02	$4.97	$5.08
MAR	$3.64	$3.90	$4.75	$4.79	$4.73	$4.84
APR92	$3.46	$3.72	$4.54	$4.57	$4.52	$4.63
MAY92	$3.33	$3.59	$4.31	$4.35	$4.29	$4.41
JUN	$3.53	$3.79	$4.55	$4.59	$4.53	$4.65
JULY	$3.73	$3.98	$4.85	$4.88	$4.83	$4.94
AUG	$3.79	$4.05	$4.93	$4.97	$4.91	$5.03
SEP192	$3.70	$3.96	$4.93	$4.96	$4.91	$5.02
OCT92	$3.76	$4.01	$5.05	$5.08	$5.03	$5.14
NOV	$3.96	$4.22	$5.25	$5.29	$5.23	$5.35
DEC	$4.16	$4.42	$5.57	$5.60	$5.55	$5.66

DATE	0.7% RESIDUAL: MARTIN	0.7% RESIDUAL: PUTNAM	1.0% SULFUR RESIDUAL FUEL OIL: CANAVERAL	1.0% SULFUR RESIDUAL FUEL OIL: EVERGLADES	1.0% SULFUR RESIDUAL FUEL OIL: FT MYERS	1.0% SULFUR RESIDUAL FUEL OIL: LAUDERDALE	1.0% SULFUR RESIDUAL FUEL OIL: MANATEE
APR91	$2.14	$2.16	$2.08	$2.04	$2.01	$2.12	$1.99
MAY91	$2.14	$2.16	$2.09	$2.04	$2.01	$2.13	$2.00
JUNE	$2.22	$2.24	$2.17	$2.12	$2.09	$2.20	$2.08
JULY	$2.64	$2.66	$2.56	$2.52	$2.48	$2.60	$2.47
AUG	$2.80	$2.81	$2.71	$2.67	$2.64	$2.75	$2.63
SEP191	$2.72	$2.76	$2.64	$2.59	$2.56	$2.68	$2.55
OCT 91	$2.88	$2.89	$2.79	$2.75	$2.71	$2.83	$2.70
NOV	$3.12	$3.14	$3.02	$2.98	$2.95	$3.06	$2.94
DEC	$3.38	$3.40	$3.27	$3.23	$3.20	$3.31	$3.18
JAN 92	$3.60	$3.70	$3.56	$3.52	$3.49	$3.60	$3.47
FEB	$3.61	$3.63	$3.49	$3.45	$3.41	$3.53	$3.40
MAR	$3.44	$3.46	$3.33	$3.29	$3.25	$3.37	$3.24
APR92	$3.28	$3.30	$3.18	$3.14	$3.10	$3.22	$3.09
MAY92	$3.13	$3.14	[illegible].03	$2.99	$2.95	$3.07	$2.94
JUN	$3.30	$3.32	$3.19	$3.15	$3.11	$3.23	$3.10
JULY	$3.51	$3.53	$3.39	$3.35	$3.32	$3.43	$3.30
AUG	$3.57	$3.59	$3.45	$3.41	$3.38	$3.49	$3.36
SEP192	$3.56	$3.58	$3.45	$3.41	$3.37	$3.49	$3.36
OC192	$3.65	$3.67	$3.53	$3.49	$3.45	$3.57	$3.44
NOV	$3.80	$3.82	$3.67	$3.63	$3.59	$3.71	$3.58
DEC	$4.02	$4.04	$3.89	$3.84	$3.81	$3.95	$3.80

DATE	1.0% SULFUR RESIDUAL FUEL OIL: RIVIERA	1.0% SULFUR RESIDUAL FUEL OIL: SANFORD	1.0% SULFUR RESIDUAL FUEL OIL: TURKEY POINT	1.5% RESIDUAL: CANAVERAL	1.5% RESIDUAL: SANFORD	1.5% RESIDUAL: FT MYERS	1% SULFUR RESIDUAL FUEL OIL: @ USGC
APR91	$2.06	$2.20	$2.03	$1.95	$2.07	$1.87	$1.86
MAY91	$2.06	$2.21	$2.04	$1.95	$2.08	$1.88	$1.86
JUNE	$2.14	$2.29	$2.11	$2.03	$2.15	$1.96	$1.95
JULY	$2.53	$2.68	$2.51	$2.43	$2.55	$2.35	$2.33
AUG	$2.69	$2.83	$2.66	$2.58	$2.70	$2.50	$2.48
SEP191	$2.61	$2.76	$2.58	$2.51	$2.63	$2.43	$2.41
OCT 91	$2.76	$2.91	$2.74	$2.66	$2.78	$2.58	$2.56
NOV	$3.00	$3.15	$2.97	$2.89	$3.01	$2.82	$2.79
DEC	$3.25	$3.39	$3.22	$3.14	$3.26	$3.06	$3.04
JAN 92	$3.54	$3.68	$3.51	$3.41	$3.53	$3.33	$3.33
FEB	$3.46	$3.61	$3.43	$3.33	$3.46	$3.26	$3.26
MAR	$3.30	$3.45	$3.27	$3.17	$3.29	$3.09	$3.10
APR92	$3.15	$3.30	$3.13	$3.02	$3.15	$2.95	$2.95
MAY92	$3.00	$3.15	$2.97	$2.87	$3.00	$2.79	$2.80
JUN	$3.17	$3.32	$3.14	$3.04	$3.16	$2.96	$2.96
JULY	$3.37	$3.52	$3.34	$3.24	$3.36	$3.16	$3.16
AUG	$3.43	$3.58	$3.40	$3.30	$3.42	$3.22	$3.22
SEP192	$3.42	$3.57	$3.39	$3.29	$3.42	$3.21	$3.22
OC192	$3.50	$3.66	$3.48	$3.37	$3.50	$3.29	$3.30
NOV	$3.64	$3.80	$3.62	$3.51	$3.64	$3.43	$3.44
DEC	$3.86	$4.01	$3.83	$3.73	$3.85	$3.65	$3.65

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D N O M I N A L D O L L A R F U E L P R I C E S I N D O L L A R S P E R M M B T U

APRIL 5, 1991

DATE	*******CRUDE OIL******* ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	*******DISTILLATE FUEL OIL************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN93	$4.41	$4.67	$5.80	$5.84	$5.78	$5.89
FEB	$4.33	$4.59	$5.70	$5.74	$5.68	$5.79
MAR	$4.20	$4.46	$5.45	$5.46	$5.43	$5.54
APR93	$4.01	$4.27	$5.23	$5.27	$5.21	$5.32
MAY 93	$3.88	$4.13	$4.99	$5.03	$4.97	$5.09
JUN	$4.09	$4.34	$5.24	$5.28	$5.22	$5.34
JUL	$4.29	$4.54	$5.55	$5.59	$5.53	$5.65
AUG	$4.34	$4.60	$5.63	$5.67	$5.61	$5.73
SEP93	$4.26	$4.52	$5.65	$5.69	$5.63	$5.75
OCT93	$4.32	$4.58	$5.78	$5.82	$5.76	$5.88
NOV	$4.52	$4.78	$5.97	$6.01	$5.95	$6.07
DEC	$4.74	$4.99	$6.32	$6.36	$6.30	$6.42
JAN94	$4.99	$5.24	$6.54	$6.58	$6.52	$6.64
FEB	$4.90	$5.15	$6.42	$6.46	$6.40	$6.52
MAR	$4.76	$5.02	$6.16	$6.19	$6.14	$6.26
APR94	$4.58	$4.83	$5.95	$5.98	$5.92	$6.04
MAY 94	$4.44	$4.70	$5.69	$5.73	$5.67	$5.79
JUN	$4.65	$4.90	$5.94	$5.98	$5.92	$6.04
JUL	$4.86	$5.12	$6.28	$6.32	$6.26	$6.38
AUG	$4.92	$5.18	$6.36	$6.40	$6.34	$6.46
SEP94	$4.83	$5.09	$6.38	$6.42	$6.36	$6.48
OCT94	$4.90	$5.15	$6.54	$6.58	$6.52	$6.64
NOV	$5.11	$5.37	$6.73	$6.77	$6.71	$6.83
DEC	$5.33	$5.59	$7.09	$7.13	$7.07	$7.19
JAN95	$5.54	$5.80	$7.15	$7.19	$7.13	$7.25
FEB	$5.45	$5.71	$6.95	$6.99	$6.92	$7.05
MAR	$5.32	$5.57	$6.76	$6.80	$6.74	$6.87
APR95	$5.13	$5.39	$6.61	$6.65	$6.59	$6.71
MAY 95	$4.99	$5.25	$6.45	$6.49	$6.43	$6.55
JUN	$5.21	$5.46	$6.87	$6.91	$6.84	$6.97
JUL	$5.43	$5.69	$7.25	$7.27	$7.21	$7.33
AUG	$5.50	$5.76	$7.23	$7.27	$7.21	$7.33
SEP95	$5.41	$5.66	$7.20	$7.24	$7.17	$7.30
OCT95	$5.48	$5.74	$7.29	$7.33	$7.27	$7.40
NOV	$5.71	$5.97	$7.50	$7.54	$7.48	$7.61
DEC	$5.95	$6.21	$7.90	$7.94	$7.88	$8.00

DATE	**0.7% RESIDUAL** MARTIN	****************1.0% SULFUR RESIDUAL FUEL OIL**** PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	*******1.5% RESIDUAL******* CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL USGC
JAN93	$4.18	$4.20	$4.04	$4.00	$3.96	$4.08	$3.95	$4.01	$4.16	$3.98	$3.86	$3.98	$3.78	$3.81
FEB	$4.11	$4.13	$3.97	$3.93	$3.89	$4.01	$3.88	$3.94	$4.10	$3.92	$3.79	$3.92	$3.71	$3.74
MAR	$3.93	$3.95	$3.80	$3.76	$3.72	$3.84	$3.71	$3.77	$3.93	$3.74	$3.62	$3.74	$3.54	$3.57
APR93	$3.77	$3.79	$3.65	$3.61	$3.57	$3.69	$3.56	$3.62	$3.78	$3.59	$3.47	$3.59	$3.39	$3.42
MAY 93	$3.61	$3.63	$3.49	$3.45	$3.41	$3.53	$3.40	$3.46	$3.62	$3.43	$3.30	$3.43	$3.22	$3.26
JUN	$3.78	$3.80	$3.66	$3.62	$3.58	$3.70	$3.57	$3.63	$3.78	$3.60	$3.47	$3.60	$3.39	$3.42
JUL	$4.00	$4.02	$3.87	$3.83	$3.79	$3.91	$3.78	$3.84	$4.00	$3.81	$3.69	$3.81	$3.61	$3.64
AUG	$4.06	$4.08	$3.93	$3.88	$3.85	$3.97	$3.83	$3.90	$4.05	$3.87	$3.74	$3.87	$3.66	$3.69
SEP93	$4.08	$4.09	$3.94	$3.90	$3.86	$3.98	$3.85	$3.91	$4.07	$3.88	$3.75	$3.88	$3.67	$3.70
OCT93	$4.17	$4.19	$4.03	$3.98	$3.95	$4.07	$3.94	$4.00	$4.16	$3.97	$3.84	$3.97	$3.76	$3.79
NOV	$4.31	$4.33	$4.16	$4.12	$4.08	$4.20	$4.07	$4.13	$4.29	$4.10	$3.97	$4.10	$3.89	$3.93
DEC	$4.55	$4.57	$4.39	$4.35	$4.31	$4.44	$4.30	$4.37	$4.52	$4.34	$4.21	$4.34	$4.13	$4.16
JAN94	$4.71	$4.75	$4.55	$4.50	$4.47	$4.59	$4.46	$4.52	$4.68	$4.49	$4.34	$4.47	$4.26	$4.31
FEB	$4.63	$4.65	$4.47	$4.43	$4.39	$4.51	$4.38	$4.44	$4.60	$4.41	$4.26	$4.39	$4.18	$4.24
MAR	$4.44	$4.46	$4.29	$4.24	$4.21	$4.33	$4.19	$4.26	$4.42	$4.25	$4.07	$4.20	$3.99	$4.05
APR94	$4.29	$4.31	$4.14	$4.10	$4.06	$4.18	$4.05	$4.11	$4.27	$4.09	$3.95	$4.06	$3.85	$3.91
MAY 94	$4.11	$4.14	$3.97	$[illegible].75	$3.89	$4.01	$3.88	$3.94	$4.10	$3.91	$3.76	$3.89	$3.68	$3.74
JUN	$4.28	$4.31	$4.14	$4.09	$4.06	$4.18	$4.04	$4.11	$4.27	$4.08	$3.92	$4.05	$3.84	$3.90
JUL	$4.53	$4.55	$4.37	$4.33	$4.29	$4.41	$4.28	$4.34	$4.50	$4.31	$4.16	$4.29	$4.07	$4.13
AUG	$4.59	$4.61	$4.43	$4.38	$4.35	$4.47	$4.33	$4.40	$4.56	$4.37	$4.21	$4.35	$4.13	$4.19
SEP94	$4.60	$4.63	$4.44	$4.40	$4.36	$4.49	$4.35	$4.41	$4.57	$4.38	$4.23	$4.36	$4.14	$4.21
OCT94	$4.71	$4.74	$4.55	$4.50	$4.47	$4.59	$4.45	$4.52	$4.68	$4.49	$4.33	$4.46	$4.25	$4.31
NOV	$4.85	$4.88	$4.68	$4.64	$4.60	$4.72	$4.59	$4.65	$4.81	$4.62	$4.47	$4.60	$4.38	$4.45
DEC	$5.11	$5.14	$4.93	$4.88	$4.84	$4.97	$4.83	$4.90	$5.06	$4.87	$4.71	$4.84	$4.63	$4.69
JAN95	$5.15	$5.18	$4.97	$4.92	$4.89	$5.01	$4.87	$4.74	$5.10	$4.91	$4.75	$4.89	$4.67	$4.73
FEB	$5.00	$5.03	$4.83	$4.78	$4.74	$4.87	$4.73	$4.80	$4.96	$4.77	$4.61	$4.74	$4.53	$4.59
MAR	$4.87	$4.90	$4.70	$4.66	$4.62	$4.75	$4.61	$4.67	$4.84	$4.64	$4.48	$4.62	$4.40	$4.47
APR95	$4.77	$4.79	$4.60	$4.56	$4.52	$4.64	$4.50	$4.57	$4.73	$4.54	$4.38	$4.52	$4.30	$4.36
MAY 95	$4.65	$4.68	$4.49	$4.45	$4.41	$4.53	$4.39	$4.46	$4.63	$4.43	$4.27	$4.41	$4.19	$4.25
JUN	$4.95	$4.98	$4.77	$4.73	$4.69	$4.82	$4.68	$4.74	$4.91	$4.71	$4.55	$4.69	$4.47	$4.54
JUL	$5.21	$5.24	$5.02	$4.98	$4.94	$5.07	$4.93	$4.99	$5.16	$4.96	$4.80	$4.94	$4.72	$4.79
AUG	$5.21	$5.24	$5.02	$4.98	$4.94	$5.07	$4.92	$4.99	$5.16	$4.56	$4.80	$4.94	$4.72	$4.70
SEP95	$5.18	$5.21	$5.00	$4.95	$4.91	$5.04	$4.90	$4.97	$5.14	$4.94	$4.78	$4.91	$4.69	$4.76
OCT95	$5.25	$5.26	$5.06	$5.02	$4.98	$5.11	$4.97	$5.04	$5.20	$5.00	$4.84	$4.98	$4.76	$4.83
NOV	$5.40	$5.43	$5.21	$5.16	$5.12	$5.25	$5.11	$5.18	$5.35	$5.15	$4.99	$5.12	$4.90	$4.97
DEC	$5.68	$5.71	$5.48	$5.43	$5.39	$5.52	$5.38	$5.45	$5.62	$5.42	$5.26	$5.39	$5.17	$5.24

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   1 9 9 1   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

APRIL 5, 1991

DATE	*******CRUDE OIL******* ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	*******DISTILLATE FUEL OIL************* EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
APR91	$15.80	$17.30	$19.23	$19.44	$19.12	$19.76
MAY91	$15.65	$16.95	$18.56	$18.77	$18.65	$19.10
JUNE	$15.75	$17.25	$18.86	$19.07	$18.75	$19.39
JULY	$18.20	$19.70	$21.86	$22.07	$21.75	$22.40
AUG	$18.95	$20.45	$22.75	$22.96	$22.64	$23.29
SEP191	$18.75	$20.25	$23.04	$23.25	$22.93	$23.58
OCT 91	$19.55	$21.05	$24.24	$24.45	$24.13	$24.78
NOV	$20.55	$22.04	$25.11	$25.32	$25.00	$25.64
DEC	$21.55	$23.04	$26.59	$26.80	$26.48	$27.12
JAN 92	$22.25	$23.73	$29.38	$29.59	$29.27	$29.91
FEB	$21.70	$23.18	$28.68	$28.09	$28.57	$29.22
MAR	$20.90	$22.38	$27.25	$27.46	$27.14	$27.79
APR92	$19.80	$21.27	$25.96	$26.17	$25.85	$26.50
MAY92	$19.00	$20.47	$24.63	$24.84	$24.52	$25.17
JUN	$20.10	$21.56	$25.93	$26.14	$25.32	$26.47
JULY	$21.15	$22.61	$27.54	$27.75	$27.43	$28.07
AUG	$21.45	$22.91	$27.96	$28.17	$27.85	$28.50
SEP192	$20.90	$22.35	$27.86	$28.07	$27.75	$28.39
OC192	$21.15	$22.60	$28.47	$28.68	$28.36	$29.00
NOV	$22.25	$23.70	$29.54	$29.75	$29.43	$30.08
DEC	$23.30	$24.74	$31.23	$31.44	$31.12	$31.76

DATE	*0.7% RESIDUAL* MARTIN	****************1.0% SULFUR RESIDUAL FUEL OIL********************************** PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	*******1.5% RESIDUAL******* CANAVERAL	SANFORD	FT MYERS	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
APR91	$13.64	$13.76	$13.26	$13.02	$12.78	$13.51	$12.71	$13.10	$14.03	$12.95	$12.40	$13.16	$11.92	$11.81
MAY91	$13.64	$13.76	$13.26	$12.99	$12.78	$13.51	$12.71	$13.10	$14.03	$12.95	$12.40	$13.16	$11.92	$11.78
JUNE	$14.16	$14.28	$13.76	$13.49	$13.28	$14.01	$13.21	$13.60	$14.53	$13.43	$12.90	$13.66	$12.42	$12.29
JULY	$16.78	$16.90	$16.26	$15.99	$15.78	$16.51	$15.71	$16.10	$17.03	$15.93	$15.40	$16.16	$14.92	$14.78
AUG	$17.83	$17.94	$17.26	$17.01	$16.78	$17.51	$16.71	$17.10	$18.03	$16.93	$16.40	$17.16	$15.92	$15.81
SEP191	$17.50	$17.42	$16.76	$16.49	$16.28	$17.01	$16.21	$16.60	$17.53	$16.43	$15.90	$16.66	$15.42	$15.29
OCT 91	$18.27	$18.39	$17.69	$17.43	$17.21	$17.94	$17.14	$17.52	$18.46	$17.35	$16.82	$17.59	$16.34	$16.23
NOV	$19.78	$19.90	$19.14	$18.88	$18.65	$19.38	$18.58	$18.97	$19.90	$18.80	$18.27	$19.06	$17.79	$17.67
DEC	$21.36	$21.48	$20.64	$20.39	$20.16	$20.89	$20.09	$20.48	$21.41	$20.31	$19.78	$20.54	$19.30	$19.18
JAN 92	$23.22	$23.33	$22.41	$22.16	$21.93	$22.66	$21.86	$22.25	$23.18	$22.08	$21.41	$22.18	$20.93	$20.95
FEB	$22.67	$22.79	$21.90	$21.64	$21.41	$22.14	$21.34	$21.75	$22.66	$21.56	$20.89	$21.66	$20.41	$20.43
MAR	$21.56	$21.68	$20.83	$20.57	$20.35	$21.08	$20.28	$20.66	$21.60	$20.49	$19.83	$20.59	$19.35	$19.37
APR92	$20.55	$20.67	$19.87	$19.61	$19.38	$20.11	$19.31	$19.70	$20.63	$19.53	$18.86	$19.63	$18.38	$18.40
MAY92	$19.51	$19.63	$18.87	$18.62	$10.39	$19.12	$18.32	$18.71	$1[illegible].64	$18.54	$17.07	$18.64	$17.39	$17.41
JUN	$20.53	$20.64	$19.84	$19.59	$19.36	$20.09	$19.29	$19.68	$20.61	$19.51	$18.84	$19.61	$18.36	$18.38
JULY	$21.78	$21.90	$21.04	$20.78	$20.56	$21.29	$20.49	$20.88	$21.81	$20.70	$20.04	$20.81	$19.56	$19.58
AUG	$22.11	$22.23	$21.36	$21.10	$20.88	$21.61	$20.81	$21.19	$22.13	$21.02	$20.36	$21.12	$19.88	$19.90
SEP192	$22.03	$22.15	$21.28	$21.02	$20.80	$21.53	$20.73	$21.11	$22.05	$20.94	$20.28	$21.06	$19.80	$19.82
OC192	$22.51	$22.62	$21.73	$21.48	$21.25	$21.98	$21.18	$21.57	$22.50	$21.40	$20.75	$21.50	$20.25	$20.27
NOV	$23.35	$23.46	$22.54	$22.28	$22.06	$22.79	$21.99	$22.37	$23.31	$22.20	$21.54	$22.30	$21.06	$21.08
DEC	$24.66	$24.78	$23.80	$23.54	$23.31	$24.04	$23.24	$23.63	$24.56	$23.46	$22.79	$23.56	$22.31	$22.33

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D 1 9 9 1 D O L L A R F U E L P R I C E S I N D O L L A R S P E R B A R R E L

APRIL 5, 1991

	*******CRUDE OIL*******		********DISTILLATE FUEL OIL**************			
DATE	ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN93	$24.65	$26.09	$32.45	$32.66	$32.34	$32.99
FEB	$24.15	$25.58	$31.82	$32.03	$31.71	$32.36
MAR	$23.35	$24.78	$30.34	$30.55	$30.23	$30.88
APR93	$22.25	$23.68	$29.06	$29.27	$28.95	$29.59
MAY 93	$21.45	$22.87	$27.68	$27.89	$27.57	$28.22
JUN	$22.55	$23.97	$28.98	$29.19	$28.87	$29.51
JUL	$23.60	$25.02	$30.62	$30.83	$30.51	$31.16
AUG	$23.85	$25.26	$30.99	$31.20	$30.88	$31.53
SEP93	$23.35	$24.76	$31.02	$31.23	$30.91	$31.55
OCT93	$23.60	$25.01	$31.66	$31.87	$31.55	$32.20
NOV	$24.65	$26.05	$32.64	$32.85	$32.53	$33.18
DEC	$25.75	$27.15	$34.43	$34.64	$34.32	$34.96
JAN94	$27.05	$28.45	$35.55	$35.76	$35.44	$36.08
FEB	$26.50	$27.89	$34.85	$35.06	$34.74	$35.38
MAR	$25.70	$27.09	$33.32	$33.53	$33.21	$33.85
APR94	$24.65	$26.04	$32.10	$32.31	$31.99	$32.64
MAY 94	$23.85	$25.23	$30.68	$30.89	$30.57	$31.22
JUN	$24.90	$26.28	$31.91	$32.12	$31.80	$32.45
JUL	$26.00	$27.38	$33.66	$33.87	$33.55	$34.19
AUG	$26.25	$27.62	$34.03	$34.26	$33.92	$34.57
SEP94	$25.70	$27.07	$34.06	$34.27	$33.95	$34.59
OCT94	$26.00	$27.37	$34.80	$35.01	$34.69	$35.34
NOV	$27.05	$28.42	$35.75	$35.96	$35.64	$36.29
DEC	$28.15	$29.51	$37.57	$37.78	$37.46	$38.11
JAN95	$29.20	$30.56	$37.78	$37.99	$37.67	$38.32
FEB	$28.65	$30.00	$36.59	$36.80	$36.48	$37.13
MAR	$27.85	$29.20	$35.54	$35.75	$35.43	$36.07
APR95	$26.80	$28.14	$34.65	$34.86	$34.54	$35.19
MAY 95	$26.00	$27.34	$33.72	$33.95	$33.61	$34.26
JUN	$27.05	$28.39	$35.78	$35.99	$35.67	$36.31
JUL	$28.15	$29.48	$37.57	$37.78	$37.46	$38.11
AUG	$28.40	$29.73	$37.46	$37.67	$37.35	$38.00
SEP95	$27.85	$29.18	$37.18	$37.39	$37.07	$37.72
OCT95	$28.15	$29.47	$37.57	$37.78	$37.46	$38.11
NOV	$29.25	$30.57	$38.55	$38.76	$38.44	$39.08
DEC	$30.40	$31.71	$40.47	$40.68	$40.36	$41.00

	0.7% RESIDUAL	***************1.0% SULFUR RESIDUAL FUEL OIL**************************************								*******1.5% RESIDUAL*******			MEMO: 1% SULFUR RESIDUAL FUEL OIL
DATE	MARTIN	PUTNAM	CANAVERAL	EVERGLADES	FT MYERS	LAUDERDALE	MANATEE	RIVIERA	SANFORD	TURKEY POINT	CANAVERAL	SANFORD	FT MYERS	@ USGC
JAN93	$25.58	$25.70	$24.67	$24.42	$24.19	$24.92	$24.12	$24.51	$25.44	$24.34	$23.57	$24.29	$23.05	$23.21
FEB	$25.09	$25.21	$24.20	$23.95	$23.72	$24.45	$23.65	$24.04	$24.97	$23.87	$23.06	$23.82	$22.58	$22.74
MAR	$23.94	$24.05	$23.10	$22.84	$22.62	$23.35	$22.55	$22.93	$23.87	$22.76	$21.95	$22.72	$21.47	$21.64
APR93	$22.93	$23.05	$22.14	$21.89	$21.66	$22.39	$21.59	$21.98	$22.91	$21.81	$21.00	$21.76	$20.52	$20.68
MAY 93	$21.86	$21.98	$21.12	$20.86	$20.64	$21.37	$20.57	$20.95	$21.88	$20.78	$19.97	$20.74	$19.49	$19.66
JUN	$22.87	$22.99	$22.08	$21.83	$21.60	$22.33	$21.53	$21.92	$22.85	$21.75	$20.94	$21.70	$20.46	$20.62
JUL	$24.16	$24.27	$23.31	$23.05	$22.83	$23.56	$22.76	$23.14	$24.08	$22.97	$22.16	$22.93	$21.68	$21.85
AUG	$24.44	$24.56	$23.59	$23.33	$23.10	$23.83	$23.03	$23.42	$24.35	$23.25	$22.44	$23.21	$21.96	$22.12
SEP93	$24.46	$24.58	$23.60	$23.35	$23.12	$23.85	$23.05	$23.44	$24.37	$23.27	$22.46	$23.22	$21.98	$22.14
OCT93	$24.96	$25.08	$24.08	$23.83	$23.60	$24.33	$23.53	$23.92	$24.85	$23.75	$22.94	$23.70	$22.46	$22.62
NOV	$25.73	$25.84	$24.81	$24.56	$24.33	$25.06	$24.26	$24.65	$25.58	$24.48	$23.67	$24.43	$23.18	$23.35
DEC	$27.12	$27.24	$26.14	$25.89	$25.66	$26.39	$25.59	$25.98	$26.91	$25.81	$25.00	$25.76	$24.52	$24.68
JAN94	$28.01	$28.13	$26.99	$26.74	$26.51	$27.24	$26.44	$26.83	$27.76	$26.66	$25.70	$26.47	$25.22	$25.53
FEB	$27.46	$27.58	$26.47	$26.21	$25.99	$26.72	$25.92	$26.30	$27.24	$26.13	$25.18	$25.94	$24.70	$25.01
MAR	$26.27	$26.39	$25.33	$25.07	$24.85	$25.58	$24.78	$25.16	$26.09	$24.99	$24.04	$24.80	$23.56	$23.87
APR94	$25.32	$25.44	$24.42	$24.17	$23.94	$24.67	$23.87	$24.26	$25.19	$24.09	$23.13	$23.90	$22.65	$22.96
MAY 94	$24.21	$24.33	$23.36	$23.11	$22.88	$23.61	$22.81	$23.20	$24.13	$23.03	$22.07	$22.84	$21.59	$21.90
JUN	$25.17	$25.29	$24.28	$24.03	$23.80	$24.53	$23.73	$24.12	$25.05	$23.95	$22.99	$23.76	$22.51	$22.82
JUL	$26.54	$26.65	$25.58	$25.33	$25.10	$25.83	$25.03	$25.42	$26.35	$25.25	$24.29	$25.06	$23.81	$24.12
AUG	$26.83	$26.94	$25.86	$25.60	$25.38	$26.11	$25.31	$25.70	$26.63	$25.52	$24.57	$25.34	$24.09	$24.40
SEP94	$26.85	$26.97	$25.88	$25.63	$25.40	$26.13	$25.33	$25.72	$26.65	$25.55	$24.59	$25.36	$24.11	$24.42
OCT94	$27.43	$27.55	$26.44	$26.18	$25.96	$26.68	$25.88	$26.27	$27.20	$26.10	$25.15	$25.91	$24.66	$24.97
NOV	$28.17	$28.29	$27.14	$26.89	$26.66	$27.39	$26.59	$26.98	$27.91	$26.81	$25.85	$26.62	$25.37	$25.68
DEC	$29.59	$29.71	$28.50	$28.24	$28.02	$28.75	$27.95	$28.34	$29.27	$28.16	$27.21	$27.98	$26.73	$27.04
JAN95	$29.76	$29.87	$28.66	$28.40	$28.18	$28.91	$28.11	$28.49	$29.43	$28.32	$27.37	$28.14	$26.89	$27.20
FEB	$28.83	$28.94	$27.77	$27.52	$27.29	$28.02	$27.22	$27.61	$28.54	$27.44	$26.48	$27.25	$26.00	$26.31
MAR	$28.00	$28.12	$26.99	$26.73	$26.50	$27.23	$26.43	$26.82	$27.75	$26.65	$25.69	$26.46	$25.21	$25.52
APR95	$27.31	$27.43	$26.32	$26.07	$25.84	$26.57	$25.77	$26.16	$27.09	$25.99	$25.03	$25.80	$24.55	$24.86
MAY 95	$26.59	$26.70	$25.63	$25.37	$25.15	$25.88	$25.08	$25.47	$26.40	$25.29	$24.34	$25.11	$23.86	$24.17
JUN	$28.19	$28.31	$27.17	$26.91	$26.68	$27.41	$26.61	$27.00	$27.93	$26.83	$25.87	$26.64	$25.39	$25.70
JUL	$29.59	$29.71	$28.50	$28.24	$28.02	$28.75	$27.95	$28.34	$29.27	$28.16	$27.21	$27.98	$26.73	$27.04
AUG	$29.51	$29.62	$28.42	$28.16	$27.94	$28.67	$27.87	$28.26	$29.19	$28.09	$27.13	$27.90	$26.65	$26.96
SEP95	$29.29	$29.41	$28.21	$27.96	$27.73	$28.46	$27.66	$28.05	$28.98	$27.88	$26.92	$27.69	$26.44	$26.75
OCT95	$29.59	$29.71	$28.50	$28.24	$28.02	$28.75	$27.95	$28.34	$29.27	$28.16	$27.21	$27.98	$26.73	$27.04
NOV	$30.35	$30.47	$29.23	$28.97	$28.75	$29.48	$28.68	$29.06	$30.00	$28.89	$27.94	$28.70	$27.46	$27.77
DEC	$31.85	$31.97	$30.66	$30.41	$30.18	$30.91	$30.11	$30.50	$31.43	$30.33	$29.37	$30.14	$28.89	$29.20

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

DELIVERED 1991 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU &
NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

APRIL 5, 1991

	********INTERRUPTIBLE SERVICE***********					**************FIRM SERVICE**************					SYSTEM WEIGHTED		*******NATURAL GAS AVAILABILITY********										*****TRANSPORTATION SERVICE******			
	P10 GAS $/MMBTU		SPOT GAS $/MMBTU		AVERAGE $/MMBTU	SPOT GAS $/MMBTU		CITRUS GAS $/MMBTU		AVERAGE $/MMBTU	AVERAGE GAS PRICE $/MMBTU		MILLION CUBIC FEET PER DAY INTERRUPTIBLE	SERVICE		FIRM SERVICE			TOTAL FPL		SPOT/MARKET GAS & USGC $/MMBTU		INTERRUPTIBLE $/MMBTU		FIRM $/MMBTU	
DATE	1991$	NOMINAL	1991$	NOMINAL	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NOMINAL	1991$	NOMINAL	PI	SPOT	TOTAL	SPOT	CITRUS	TOTAL	SYSTEM	DATE	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL
APR91	$1.78	$1.78	$1.63	$1.63	$1.70	$1.68	$1.68	$1.87	$1.87	$1.85	$1.82	$1.82	39	38	77	28	252	280	357	APR91	$1.30	$1.30	$0.33	$0.33	$0.38	$0.38
MAY91	$1.78	$1.78	$1.62	$1.62	$0.00	$1.68	$1.68	$1.87	$1.87	$1.85	$1.85	$1.85	0	0	0	39	353	392	392	MAY91	$1.30	$1.30	$0.32	$0.32	$0.38	$0.38
JUNE	$1.85	$1.85	$1.62	$1.62	$0.00	$1.68	$1.68	$1.95	$1.95	$1.92	$1.92	$1.92	0	0	0	39	353	392	392	JUNE	$1.30	$1.30	$0.32	$0.32	$0.38	$0.38
JULY	$2.23	$2.23	$1.73	$1.73	$0.00	$1.78	$1.78	$2.35	$2.35	$2.21	$2.21	$2.21	0	0	0	98	294	392	392	JULY	$1.40	$1.40	$0.33	$0.33	$0.38	$0.38
AUG	$2.38	$2.38	$1.83	$1.83	$0.00	$1.88	$1.88	$2.51	$2.51	$2.35	$2.35	$2.35	0	0	0	98	294	392	392	AUG	$1.50	$1.50	$0.33	$0.33	$0.38	$0.38
SEP1	$2.31	$2.31	$1.95	$1.95	$0.00	$1.98	$1.98	$2.43	$2.43	$2.38	$2.38	$2.38	0	0	0	39	353	392	392	SEP191	$1.60	$1.60	$0.33	$0.33	$0.38	$0.38
OCT	$2.45	$2.45	$2.07	$2.07	$2.27	$2.12	$2.13	$2.52	$2.52	$2.48	$2.42	$2.43	50	49	99	28	252	280	379	OCT 91	$1.73	$1.74	$0.33	$0.33	$0.39	$0.39
NOV	$2.67	$2.68	$2.28	$2.30	$2.49	$2.34	$2.35	$2.81	$2.82	$2.78	$2.65	$2.66	82	82	164	25	230	255	419	NOV	$1.95	$1.96	$0.34	$0.34	$0.39	$0.39
DEC	$2.89	$2.92	$2.52	$2.54	$2.73	$2.57	$2.59	$3.04	$3.07	$3.02	$2.91	$2.93	57	57	114	25	230	255	369	DEC	$2.17	$2.19	$0.34	$0.35	$0.40	$0.40
JAN	$3.16	$3.20	$2.36	$2.38	$2.79	$2.41	$2.44	$3.33	$3.36	$3.13	$3.04	$3.07	26	26	52	64	191	255	307	JAN 92	$2.01	$2.03	$0.35	$0.35	$0.40	$0.40
FEB	$3.08	$3.12	$2.27	$2.30	$2.71	$2.33	$2.36	$3.24	$3.29	$3.06	$2.92	$2.96	51	51	102	64	191	255	357	FEB	$1.93	$1.95	$0.35	$0.35	$0.40	$0.40
MAR	$2.92	$2.97	$2.17	$2.20	$2.59	$2.22	$2.26	$3.07	$3.13	$2.91	$2.75	$2.79	74	73	147	64	191	255	402	MAR	$1.83	$1.86	$0.34	$0.35	$0.39	$0.40
APR92	$2.78	$2.83	$2.07	$2.11	$2.47	$2.13	$2.17	$2.92	$2.98	$2.77	$2.62	$2.67	79	78	157	70	210	280	437	APR92	$1.74	$1.77	$0.34	$0.34	$0.39	$0.40
MAY92	$2.63	$2.68	$1.97	$2.02	$2.35	$2.02	$2.07	$2.76	$2.82	$2.64	$2.58	$2.63	3	3	6	107	323	430	436	MAY92	$1.64	$1.68	$0.33	$0.34	$0.38	$0.39
JUN	$2.77	$2.84	$2.07	$2.12	$2.48	$2.12	$2.17	$2.92	$2.99	$2.79	$2.71	$2.78	3	3	6	107	323	430	436	JUN	$1.73	$1.78	$0.33	$0.34	$0.38	$0.39
JULY	$2.95	$3.03	$2.18	$2.24	$2.64	$2.23	$2.30	$2.94	$3.01	$2.84	$2.75	$2.82	14	13	27	107	323	430	457	JULY	$1.85	$1.90	$0.34	$0.34	$0.39	$0.40
AUG	$3.00	$3.09	$2.28	$2.34	$0.00	$2.33	$2.40	$2.99	$3.08	$2.91	$2.83	$2.91	0	0	0	107	323	430	430	AUG	$1.94	$2.00	$0.34	$0.35	$0.39	$0.40
SEP19	$2.99	$3.09	$2.40	$2.47	$2.78	$2.45	$2.53	$3.01	$3.10	$2.96	$2.86	$2.95	11	11	22	107	323	430	452	SEP192	$2.06	$2.12	$0.34	$0.35	$0.39	$0.40
OCT92	$3.06	$3.16	$2.57	$2.66	$2.92	$2.63	$2.72	$3.10	$3.21	$3.16	$2.96	$3.06	90	89	179	28	252	280	459	OCT192	$2.23	$2.31	$0.34	$0.36	$0.39	$0.41
NOV	$3.18	$3.30	$2.73	$2.84	$3.07	$2.78	$2.89	$3.23	$3.35	$3.30	$3.08	$3.19	117	116	233	25	230	255	488	NOV	$2.39	$2.48	$0.35	$0.36	$0.40	$0.41
DEC	$3.37	$3.50	$2.91	$3.03	$3.27	$2.97	$3.09	$3.41	$3.55	$3.51	$3.27	$3.40	95	95	190	25	230	255	445	DEC	$2.56	$2.67	$0.35	$0.37	$0.40	$0.42

[illegible]

3.11

2.76

2.54

2.4918

2.4837

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   1 9 9 1   D O L L A R   &   N O M I N A L   D O L L A R   N A T U R A L   G A S   P R I C E S   I N   D O L L A R S   P E R   M M B T U   &
N A T U R A L   G A S   A V A I L A B I L I T Y   I N   M I L L I O N S   O F   C U B I C   F E E T   P E R   D A Y

APRIL 5, 1991

DATE	********INTERRUPTIBLE SERVICE************ P10 GAS $/MMBTU 1991$	NOMINAL	SPOT GAS $/MMBTU 1991$	NOMINAL	AVERAGE $/MMBTU NOMINAL	***************FIRM SERVICE*************** SPOT GAS $/MMBTU 1991$	NOMINAL	CITRUS GAS $/MMBTU 1991$	NOMINAL	AVERAGE $/MMBTU NOMINAL	SYSTEM WEIGHTED AVERAGE GAS PRICE $/MMBTU 1991$	NOMINAL
JAN93	$3.50	$3.65	$2.80	$2.92	$0.00	$2.85	$2.97	$3.53	$3.69	$3.51	$3.36	$3.51
FEB	$3.43	$3.59	$2.67	$2.80	$3.19	$2.75	$2.85	$3.46	$3.62	$3.43	$3.26	$3.39
MAR	$3.26	$3.42	$2.56	$2.68	$3.05	$2.61	$2.73	$3.30	$3.46	$3.28	$3.07	$3.22
APR93	$3.12	$3.28	$2.46	$2.58	$2.95	$2.51	$2.63	$3.15	$3.31	$3.14	$2.95	$3.08
MAY	$2.96	$3.12	$2.53	$2.67	$0.00	$2.58	$2.72	$3.00	$3.16	$3.12	$2.96	$3.12
JUN	$3.11	$3.28	$2.68	$2.83	$0.00	$2.75	$2.88	$3.15	$3.32	$3.28	$3.11	$3.28
JUL	$3.29	$3.49	$2.82	$2.98	$0.00	$2.87	$3.04	$3.33	$3.52	$3.47	$3.28	$3.47
AUG	$3.34	$3.54	$2.96	$3.14	$0.00	$3.01	$3.19	$3.38	$3.59	$3.55	$3.34	$3.55
SEP93	$3.34	$3.55	$3.17	$3.37	$0.00	$3.22	$3.43	$3.40	$3.62	$3.60	$3.39	$3.60
OCT93	$3.41	$3.64	$3.30	$3.53	$3.58	$3.36	$3.58	$3.48	$3.71	$3.70	$3.43	$3.66
NOV	$3.52	$3.77	$3.55	$3.80	$3.77	$3.60	$3.85	$3.59	$3.84	$3.84	$3.56	$3.81
DEC	$3.72	$3.99	$4.05	$4.34	$4.34	$4.10	$4.40	$3.79	$4.06	$4.06	$3.88	$4.16
JAN94	$3.85	$4.14	$3.82	$4.10	$0.00	$3.87	$4.15	$3.92	$4.21	$4.20	$3.91	$4.20
FEB	$3.77	$4.06	$3.70	$3.99	$4.03	$3.75	$4.04	$3.84	$4.13	$4.12	$3.81	$4.11
MAR	$3.60	$3.89	$3.51	$3.79	$3.84	$3.56	$3.84	$3.66	$3.96	$3.95	$3.62	$3.91
APR94	$3.46	$3.75	$3.20	$3.47	$3.61	$3.25	$3.52	$3.52	$3.81	$3.78	$3.45	$3.73
MAY 9	$3.30	$3.58	$2.96	$3.21	$0.00	$3.01	$3.27	$3.35	$3.64	$3.60	$3.32	$3.60
JUN	$3.44	$3.74	$3.00	$3.26	$0.00	$3.05	$3.32	$3.48	$3.78	$3.73	$3.43	$3.73
JUL	$3.64	$3.97	$3.16	$3.44	$0.00	$3.21	$3.50	$3.66	$4.00	$3.95	$3.62	$3.95
AUG	$3.68	$4.02	$3.31	$3.61	$0.00	$3.36	$3.67	$3.72	$4.07	$4.03	$3.69	$4.03
SEP94	$3.68	$4.03	$3.54	$3.88	$0.00	$3.59	$3.94	$3.75	$4.10	$4.09	$3.73	$4.09
OCT94	$3.77	$4.14	$3.70	$4.06	$4.10	$3.75	$4.11	$3.83	$4.21	$4.20	$3.79	$4.16
NOV	$3.87	$4.26	$3.96	$4.36	$4.26	$4.01	$4.41	$3.94	$4.33	$4.33	$3.91	$4.30
DEC	$4.08	$4.50	$4.50	$4.96	$4.96	$4.54	$5.02	$4.14	$4.57	$4.57	$4.27	$4.72
JAN95	$4.10	$4.54	$4.18	$4.62	$0.00	$4.23	$4.68	$4.16	$4.61	$4.61	$4.16	$4.61
FEB	$3.97	$4.40	$4.01	$4.45	$4.40	$4.06	$4.50	$4.03	$4.47	$4.47	$4.02	$4.46
MAR	$3.85	$4.28	$3.85	$4.29	$4.28	$3.90	$4.34	$3.91	$4.35	$4.35	$3.90	$4.34
APR95	$3.75	$4.18	$3.56	$3.98	$4.08	$3.61	$4.03	$3.81	$4.25	$4.25	$3.76	$4.20
MAY	$3.64	$4.08	$3.36	$3.76	$0.00	$3.41	$3.81	$3.70	$4.14	$4.11	$3.67	$4.11
JUN	$3.88	$4.35	$3.47	$3.89	$0.00	$3.52	$3.95	$3.91	$4.39	$4.35	$3.87	$4.35
JUL	$4.08	$4.59	$3.64	$4.09	$0.00	$3.69	$4.15	$4.11	$4.63	$4.58	$4.07	$4.58
AUG	$4.07	$4.59	$3.76	$4.24	$0.00	$3.80	$4.29	$4.06	$4.58	$4.55	$4.03	$4.55
SEP95	$4.03	$4.57	$3.99	$4.51	$0.00	$4.03	$4.57	$4.03	$4.57	$4.57	$4.03	$4.57
OCT95	$4.08	$4.63	$4.11	$4.67	$4.63	$4.16	$4.72	$4.08	$4.63	$4.63	$4.08	$4.63
NOV	$4.19	$4.77	$4.39	$5.00	$4.77	$4.44	$5.05	$4.19	$4.77	$4.77	$4.19	$4.77
DEC	$4.40	$5.03	$4.97	$5.68	$5.68	$5.02	$5.75	$4.40	$5.03	$5.03	$4.57	$5.22

********NATURAL GAS AVAILABILITY******** MILLION CUBIC FEET PER DAY INTERRUPTIBLE SERVICE PI	SPOT	TOTAL	FIRM SERVICE SPOT	CITRUS	TOTAL	TOTAL FPL SYSTEM	DATE	SPOT/MARKET GAS @ USGC $/MMBTU 1991$	NOMINAL	*****TRANSPORTATION SERVICE****** INTERRUPTIBLE $/MMBTU 1991$	NOMINAL	FIRM $/MMBTU 1991$	NOMINAL
0	0	0	64	191	255	255	JAN93	$2.45	$2.55	$0.35	$0.37	$0.40	$0.42
24	24	48	64	191	255	303	FEB	$2.32	$2.43	$0.35	$0.37	$0.40	$0.42
49	48	97	64	191	255	352	MAR	$2.21	$2.32	$0.35	$0.36	$0.40	$0.42
56	55	111	70	210	280	391	APR93	$2.11	$2.22	$0.34	$0.36	$0.39	$0.41
0	0	0	43	387	430	430	MAY 93	$2.19	$2.31	$0.34	$0.36	$0.39	$0.41
0	0	0	43	387	430	430	JUN	$2.33	$2.47	$0.34	$0.36	$0.39	$0.41
0	0	0	43	387	430	430	JUL	$2.47	$2.62	$0.35	$0.37	$0.40	$0.42
0	0	0	43	387	430	430	AUG	$2.61	$2.77	$0.35	$0.37	$0.40	$0.42
0	0	0	43	387	430	430	SEP93	$2.82	$3.00	$0.35	$0.37	$0.40	$0.43
68	67	135	28	252	280	415	OCT93	$2.95	$3.15	$0.35	$0.38	$0.40	$0.43
192	0	192	0	255	255	447	NOV	$3.19	$3.42	$0.36	$0.38	$0.41	$0.44
0	145	145	0	255	255	400	DEC	$3.60	$3.95	$0.37	$0.39	$0.42	$0.45
0	0	0	25	230	255	255	JAN94	$3.45	$3.71	$0.36	$0.39	$0.41	$0.44
28	27	55	25	230	255	310	FEB	$3.34	$3.60	$0.36	$0.39	$0.41	$0.44
52	52	104	25	230	255	359	MAR	$3.15	$3.40	$0.36	$0.38	$0.41	$0.44
58	58	116	28	252	280	396	APR94	$2.85	$3.09	$0.35	$0.38	$0.40	$0.43
0	0	0	43	387	430	430	MAY 94	$2.62	$2.84	$0.34	$0.37	$0.39	$0.43
0	0	0	43	387	430	430	JUN	$2.66	$2.89	$0.35	$0.38	$0.40	$0.43
0	0	0	43	387	430	430	JUL	$2.81	$3.06	$0.35	$0.38	$0.40	$0.44
0	0	0	43	387	430	430	AUG	$2.95	$3.23	$0.35	$0.39	$0.40	$0.44
0	0	0	43	387	430	430	SEP94	$3.19	$3.49	$0.36	$0.39	$0.41	$0.45
71	70	141	28	252	280	421	OCT94	$3.34	$3.67	$0.36	$0.39	$0.41	$0.45
197	0	197	0	255	255	452	NOV	$3.59	$3.96	$0.36	$0.40	$0.41	$0.45
0	151	.31	0	255	255	406	DEC	$4.12	$4.55	$0.37	$0.41	$0.42	$0.46
0	0	0	0	255	255	255	JAN95	$3.81	$4.22	$0.37	$0.41	$0.42	$0.46
41	0	41	0	255	255	296	FEB	$3.64	$4.04	$0.36	$0.40	$0.41	$0.46
75	0	75	25	230	255	330	MAR	$3.50	$3.89	$0.36	$0.40	$0.41	$0.45
42	41	83	28	252	280	363	APR95	$3.21	$3.58	$0.35	$0.40	$0.40	$0.45
0	0	0	43	387	430	430	MAY 95	$3.01	$3.36	$0.35	$0.39	$0.40	$0.45
0	0	0	43	387	430	430	JUN	$3.12	$3.50	$0.35	$0.40	$0.40	$0.45
0	0	0	43	387	430	430	JUL	$3.28	$3.69	$0.36	$0.40	$0.41	$0.46
0	0	0	43	387	430	430	AUG	$3.40	$3.83	$0.36	$0.41	$0.41	$0.46
0	0	0	43	387	430	430	SEP95	$3.62	$4.10	$0.36	$0.41	$0.41	$0.47
101	0	101	0	280	280	381	OCT95	$3.75	$4.25	$0.36	$0.41	$0.41	$0.47
142	0	142	0	255	255	397	NOV	$4.02	$4.58	$0.37	$0.42	$0.42	$0.47
0	109	109	0	255	255	364	DEC	$4.60	$5.25	$0.38	$0.43	$0.43	$0.49

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D 1 9 9 1 D O L L A R & N O M I N A L D O L L A R C O A L P R I C E S I N D O L L A R S P E R T O N & P E R M M B T U

APRIL 5, 1991

	ST. JOHNS RIVER POWER PARK COAL (WEIGHTED AVERAGE CONTRACT/SPOT PRICE)				ST. JOHNS RIVER POWER PARK COAL S P O T C O A L P R I C E				SCHERER UNIT NUMBER FOUR PROCUREMENT STRATEGY FORECAST			
	$/TON		$/MMBTU		$/TON		$/MMBTU		NOMINAL $/TON		NOMINAL $/MMBTU	
DATE	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	EASTERN COMPLIANCE	WESTERN COMPLIANCE	EASTERN COMPLIANCE	WESTERN COMPLIANCE
APR91	$44.77	$44.77	$1.84	$1.84	$38.50	$38.50	$1.60	$1.60	$45.12	$28.51	$1.88	$1.64
MAY91	$44.77	$44.77	$1.84	$1.84	$38.50	$38.50	$1.60	$1.60	$45.12	$28.51	$1.88	$1.64
JUNE	$44.77	$44.77	$1.84	$1.84	$38.50	$38.50	$1.60	$1.60	$45.12	$28.51	$1.88	$1.64
JULY	$44.77	$44.77	$1.84	$1.84	$39.47	$39.47	$1.64	$1.64	$45.12	$28.51	$1.88	$1.64
AUG	$44.77	$44.77	$1.84	$1.84	$39.47	$39.47	$1.64	$1.64	$45.12	$28.51	$1.88	$1.64
SEPT91	$44.77	$44.77	$1.84	$1.84	$39.47	$39.47	$1.64	$1.64	$45.12	$28.51	$1.88	$1.64
OCT 91	$44.89	$45.02	$1.84	$1.85	$40.55	$40.66	$1.68	$1.69	$45.36	$28.69	$1.89	$1.65
NOV	$44.75	$45.02	$1.84	$1.85	$40.43	$40.66	$1.68	$1.69	$45.36	$28.69	$1.89	$1.65
DEC	$44.62	$45.01	$1.83	$1.85	$40.31	$40.66	$1.68	$1.69	$45.36	$28.69	$1.89	$1.65
JAN 92	$42.54	$43.08	$1.75	$1.77	$40.74	$41.70	$1.69	$1.73	$45.60	$28.69	$1.90	$1.65
FEB	$42.43	$43.08	$1.75	$1.77	$40.63	$41.70	$1.69	$1.73	$45.60	$28.69	$1.90	$1.65
MAR	$42.32	$43.08	$1.75	$1.77	$40.52	$41.70	$1.69	$1.73	$45.60	$28.69	$1.90	$1.65
APR92	$42.54	$43.42	$1.75	$1.79	$40.74	$42.03	$1.69	$1.75	$45.84	$28.86	$1.91	$1.66
MAY92	$42.43	$43.42	$1.75	$1.79	$40.63	$42.03	$1.69	$1.75	$45.84	$28.86	$1.91	$1.66
JUN	$42.32	$43.41	$1.75	$1.79	$40.52	$42.03	$1.69	$1.75	$45.84	$28.86	$1.91	$1.66
JULY	$42.29	$43.74	$1.74	$1.80	$40.98	$42.60	$1.70	$1.77	$46.32	$29.21	$1.93	$1.68
AUG	$42.17	$43.73	$1.74	$1.80	$40.87	$42.60	$1.70	$1.77	$46.32	$29.21	$1.93	$1.68
SEP192	$42.04	$43.71	$1.73	$1.80	$40.76	$42.60	$1.70	$1.77	$46.32	$29.21	$1.93	$1.68
OCT92	$42.22	$43.76	$1.74	$1.80	$41.22	$43.18	$1.71	$1.80	$46.56	$29.38	$1.94	$1.69
NOV	$42.08	$43.73	$1.74	$1.80	$41.11	$43.18	$1.71	$1.80	$46.56	$29.38	$1.94	$1.69
DEC	$41.92	$43.68	$1.73	$1.80	$41.00	$43.18	$1.71	$1.80	$46.56	$29.38	$1.94	$1.69

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

DELIVERED 1991 DOLLAR & NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON & PER MMBTU

APRIL 5, 1991

	ST. JOHNS RIVER POWER PARK COAL (WEIGHTED AVERAGE CONTRACT/SPOT PRICE)				ST. JOHNS RIVER POWER PARK COAL SPOT COAL PRICE				SCHERER UNIT NUMBER FOUR PROCUREMENT STRATEGY FORECAST			
	$/TON		$/MMBTU		$/TON		$/MMBTU		NOMINAL $/TON		NOMINAL $/MMBTU	
DATE	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	EASTERN COMPLIANCE	WESTERN COMPLIANCE	EASTERN COMPLIANCE	WESTERN COMPLIANCE
JAN93	$42.46	$44.46	$1.74	$1.83	$40.95	$43.36	$1.70	$1.81	$47.04	$29.56	$1.96	$1.70
FEB	$42.36	$44.46	$1.74	$1.83	$40.85	$43.36	$1.70	$1.81	$47.04	$29.56	$1.96	$1.70
MAR	$42.25	$44.46	$1.74	$1.83	$40.75	$43.36	$1.70	$1.81	$47.04	$29.56	$1.96	$1.70
APR93	$42.71	$45.05	$1.75	$1.85	$41.19	$43.93	$1.71	$1.83	$47.28	$29.56	$1.97	$1.70
MAY 93	$42.60	$45.05	$1.75	$1.85	$41.09	$43.93	$1.71	$1.83	$47.28	$29.56	$1.97	$1.70
JUN	$42.48	$45.04	$1.75	$1.85	$40.99	$43.93	$1.71	$1.83	$47.28	$29.56	$1.97	$1.70
JUL	$42.68	$45.36	$1.75	$1.87	$41.19	$44.26	$1.71	$1.85	$47.76	$29.56	$1.99	$1.70
AUG	$42.56	$45.34	$1.75	$1.87	$41.09	$44.26	$1.71	$1.85	$47.76	$29.56	$1.99	$1.70
SEP93	$42.40	$45.29	$1.74	$1.86	$40.99	$44.26	$1.71	$1.85	$47.76	$29.56	$1.99	$1.70
OCT93	$42.80	$45.82	$1.76	$1.89	$41.44	$44.85	$1.72	$1.87	$48.00	$29.56	$2.00	$1.70
NOV	$42.63	$45.76	$1.75	$1.88	$41.33	$44.85	$1.72	$1.87	$48.00	$29.56	$2.00	$1.70
DEC	$42.43	$45.65	$1.74	$1.88	$41.23	$44.85	$1.72	$1.87	$48.00	$29.56	$2.00	$1.70
JAN94	$43.19	$46.59	$1.77	$1.91	$41.19	$45.20	$1.71	$1.89	$48.24	$29.56	$2.01	$1.70
FEB	$43.09	$46.59	$1.77	$1.91	$41.09	$45.20	$1.71	$1.89	$48.24	$29.56	$2.01	$1.70
MAR	$42.98	$46.59	$1.77	$1.91	$40.99	$45.20	$1.71	$1.89	$48.24	$29.56	$2.01	$1.70
APR94	$43.43	$47.19	$1.78	$1.93	$41.43	$45.79	$1.72	$1.91	$48.48	$29.73	$2.02	$1.71
MAY 94	$43.33	$47.19	$1.78	$1.93	$41.33	$45.79	$1.72	$1.91	$48.48	$29.73	$2.02	$1.71
JUN	$43.21	$47.17	$1.77	$1.93	$41.23	$45.79	$1.72	$1.91	$48.48	$29.73	$2.02	$1.71
JUL	$43.39	$47.48	$1.78	$1.94	$41.67	$46.39	$1.73	$1.93	$48.96	$29.73	$2.04	$1.71
AUG	$43.25	$47.45	$1.78	$1.94	$41.57	$46.39	$1.73	$1.93	$48.96	$29.73	$2.04	$1.71
SEP94	$43.08	$47.37	$1.77	$1.94	$41.47	$46.39	$1.73	$1.93	$48.96	$29.73	$2.04	$1.71
OCT94	$43.67	$48.14	$1.79	$1.97	$41.67	$46.72	$1.73	$1.95	$49.20	$29.90	$2.05	$1.72
NOV	$43.46	$48.02	$1.79	$1.97	$41.57	$46.72	$1.73	$1.95	$49.20	$29.90	$2.05	$1.72
DEC	$43.21	$47.86	$1.78	$1.96	$41.47	$46.72	$1.73	$1.95	$49.20	$29.90	$2.05	$1.72
JAN95	$43.84	$48.83	$1.80	$2.00	$41.32	$47.25	$1.73	$1.96	$49.68	$30.43	$2.07	$1.75
FEB	$43.72	$48.83	$1.79	$2.00	$41.20	$47.25	$1.72	$1.96	$49.68	$30.43	$2.07	$1.75
MAR	$43.59	$48.83	$1.78	$2.00	$41.08	$47.25	$1.72	$1.96	$49.68	$30.43	$2.07	$1.75
APR95	$44.09	$49.52	$1.81	$2.03	$41.56	$47.92	$1.74	$1.99	$50.16	$31.12	$2.09	$1.79
MAY 95	$43.96	$49.52	$1.80	$2.03	$41.44	$47.92	$1.73	$1.99	$50.16	$31.12	$2.09	$1.79
JUN	$43.81	$49.49	$1.79	$2.02	$41.32	$47.92	$1.72	$1.99	$50.16	$31.12	$2.09	$1.79
JUL	$44.27	$50.15	$1.81	$2.05	$41.56	$48.33	$1.74	$2.01	$50.64	$31.99	$2.11	$1.84
AUG	$44.09	$50.09	$1.81	$2.05	$41.44	$48.33	$1.73	$2.01	$50.64	$31.99	$2.11	$1.84
SEP95	$43.87	$49.98	$1.80	$2.04	$41.32	$48.33	$1.72	$2.01	$50.64	$31.99	$2.11	$1.84
OCT95	$44.22	$50.80	$1.81	$2.08	$42.04	$49.29	$1.76	$2.05	$51.12	$33.03	$2.13	$1.90
NOV	$43.92	$50.61	$1.80	$2.07	$41.92	$49.29	$1.75	$2.05	$51.12	$33.03	$2.13	$1.90
DEC	$43.61	$50.39	$1.79	$2.06	$41.80	$49.29	$1.74	$2.05	$51.12	$33.03	$2.13	$1.90

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   O R I M U L S I O N   P R I C E S   I N   D O L L A R S   P E R   M M B T U
& P E R   T O N

APRIL 5, 1991

DATE	SANFORD $/MMBTU	PORT EVERGLADES $/MMBTU	MANATEE $/MMBTU	CANAVERAL $/MMBTU	MARTIN $/MMBTU	SANFORD $/TON	PORT EVERGLADES $/TON	MANATEE $/TON	CANAVERAL $/TON	MARTIN $/TON
APR91	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
MAY91	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
JUNE	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
JULY	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
AUG	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
SEPT91	$2.09	$1.92	$1.91	$1.97	$1.92	$53.44	$49.23	$49.02	$50.36	$49.18
OCT 91	$2.10	$1.93	$1.93	$1.98	$1.93	$53.74	$49.50	$49.30	$50.64	$49.45
NOV	$2.10	$1.93	$1.93	$1.98	$1.93	$53.73	$49.50	$49.29	$50.63	$49.44
DEC	$2.10	$1.93	$1.93	$1.98	$1.93	$53.72	$49.49	$49.28	$50.62	$49.44
JAN 92	$2.02	$1.86	$1.85	$1.90	$1.85	$51.69	$47.50	$47.30	$48.63	$47.45
FEB	$2.02	$1.86	$1.85	$1.90	$1.85	$51.69	$47.50	$47.30	$48.63	$47.45
MAR	$2.02	$1.86	$1.85	$1.90	$1.85	$51.69	$47.50	$47.30	$48.63	$47.45
APR92	$2.0[illegible]	$1.87	$1.86	$1.91	$1.87	$52.09	$47.87	$47.67	$49.00	$47.82
MAY92	$2.03	$1.87	$1.86	$1.91	$1.87	$52.09	$47.87	$47.67	$49.00	$47.82
JUN	$2.03	$1.87	$1.86	$1.91	$1.87	$52.09	$47.87	$47.66	$49.00	$47.82
JULY	$2.05	$1.88	$1.88	$1.93	$1.88	$52.48	$48.23	$48.02	$49.37	$48.18
AUG	$2.05	$1.88	$1.88	$1.93	$1.88	$52.47	$48.22	$48.01	$49.36	$48.17
SEPT92	$2.05	$1.88	$1.87	$1.93	$1.88	$52.44	$48.20	$47.99	$49.34	$48.15
OCT92	$2.05	$1.88	$1.88	$1.93	$1.88	$52.50	$48.25	$48.04	$49.39	$48.20
NOV	$2.05	$1.88	$1.88	$1.93	$1.88	$52.46	$48.22	$48.01	$49.36	$48.16
DEC	$2.05	$1.88	$1.87	$1.93	$1.88	$52.40	$48.16	$47.95	$49.30	$48.11

APRIL 1991 TO DECEMBER 1995 SHORT-TERM FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLAR PRICES

DELIVERED NOMINAL DOLLAR ORIMULSION PRICES IN DOLLARS PER MMBTU & PER TON

APRIL 5, 1991

DATE	SANFORD $/MMBTU	PORT EVERGLADES $/MMBTU	MANATEE $/MMBTU	CAPE CANAVERAL $/MMBTU	MARTIN $/MMBTU	SANFORD $/TON	PORT EVERGLADES $/TON	MANATEE $/TON	CAPE CANAVERAL $/TON	MARTIN $/TON
JAN93	$2.07	$1.91	$1.90	$1.96	$1.91	$53.11	$48.95	$48.75	$50.06	$48.90
FEB	$2.07	$1.91	$1.90	$1.96	$1.91	$53.11	$48.95	$48.75	$50.06	$48.90
MAR	$2.07	$1.91	$1.90	$1.96	$1.91	$53.11	$48.95	$48.75	$50.06	$48.90
APR93	$2.10	$1.94	$1.93	$1.98	$1.94	$53.81	$49.60	$49.39	$50.73	$49.55
MAY 93	$2.10	$1.94	$1.93	$1.98	$1.94	$53.81	$49.60	$49.39	$50.73	$49.55
JUN	$2.10	$1.94	$1.93	$1.98	$1.93	$53.80	$49.59	$49.38	$50.72	$49.54
JUL	$2.12	$1.95	$1.94	$2.00	$1.95	$54.18	$49.94	$49.73	$51.08	$49.89
AUG	$2.12	$1.95	$1.94	$1.99	$1.95	$54.16	$49.92	$49.71	$51.06	$49.87
SEP93	$2.11	$1.95	$1.94	$1.99	$1.95	$54.10	$49.87	$49.66	$51.00	$49.81
OCT93	$2.14	$1.97	$1.96	$2.02	$1.97	$54.74	$50.45	$50.24	$51.60	$50.40
NOV	$2.14	$1.97	$1.96	$2.01	$1.97	$54.66	$50.38	$50.17	$51.52	$50.32
DEC	$2.13	$1.96	$1.96	$2.01	$1.96	$54.54	$50.27	$50.06	$51.41	$50.21
JAN94	$2.15	$1.99	$1.98	$2.03	$1.99	$55.09	$50.95	$50.75	$52.07	$50.90
FEB	$2.15	$1.99	$1.98	$2.03	$1.99	$55.09	$50.95	$50.75	$52.07	$50.90
MAR	$2.15	$1.99	$1.98	$2.03	$1.99.	$55.09	$50.95	$50.75	$52.07	¢50.90
APR94	$2.18	$2.02	$2.01	$2.06	$2.01	$55.81	$51.61	$51.41	$52.74	$51.56
MAY 94	$2.18	$2.02	$2.01	$2.06	$2.01	$55.81	$51.61	$51.41	$52.74	$51.56
JUN	$2.18	$2.02	$2.01	$2.06	$2.01	$55.79	$51.59	$51.39	$52.72	$51.54
JUL	$2.19	$2.03	$2.02	$2.07	$2.03	$56.16	$51.94	$51.73	$53.07	$51.89
AUG	$2.19	$2.03	$2.02	$2.07	$2.03	$56.12	$51.90	$51.69	$53.03	$51.85
SEP94	$2.19	$2.02	$2.02	$2.07	$2.02	$56.03	$51.82	$51.61	$52.95	$51.76
OCT94	$2.22	$2.06	$2.05	$2.10	$2.05	$56.93	$52.65	$52.44	$53.80	$52.60
NOV	$2.22	$2.05	$2.04	$2.10	$2.05	$56.79	$52.52	$52.31	$53.66	$52.47
DEC	$2.21	$2.05	$2.04	$2.09	$2.04	$56.61	$52.35	$52.15	$53.49	$52.30
JAN95	$2.24	$2.08	$2.08	$2.13	$2.08	$57.46	$53.33	$53.13	$54.44	$53.28
FEB	$2.24	$2.08	$2.08	$2.13	$2.08	$57.46	$53.33	$53.13	$54.44	$53.28
MAR	$2.24	$2.08	$2.08	$2.13	$2.08	$57.46	$53.33	$53.13	$54.44	$53.28
APR95	$2.28	$2.11	$2.10	$2.16	$2.11	$58.27	$54.09	$53.88	$55.21	$54.03
MAY 95	$2.28	$2.11	$2.10	$2.16	$2.11	$58.27	$54.09	$53.88	$55.21	$54.03
JUN	$2.27	$2.11	$2.10	$2.16	$2.11	$58.24	$54.05	$53.85	$55.17	$54.00
JUL	$2.31	$2.14	$2.13	$2.18	$2.14	$59.01	$54.77	$54.56	$55.91	$54.72
AUG	$2.30	$2.14	$2.13	$2.18	$2.13	$58.94	$54.70	$54.50	$55.84	$54.65
SEP95	$2.30	$2.13	$2.12	$2.18	$2.13	$58.81	$54.58	$54.38	$55.72	$54.53
OCT95	$2.33	$2.17	$2.16	$2.21	$2.16	$59.77	$55.48	$55.27	$56.63	$55.42
NOV	$2.33	$2.16	$2.15	$2.20	$2.16	$59.55	$55.27	$55.06	$56.42	$55.22
DEC	$2.32	$2.15	$2.14	$2.19	$2.15	$59.30	$55.04	$54.83	$56.18	$54.98

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

C O N S T A N T   1 9 9 1   D O L L A R   &   N O M I N A L   D O L L A R   C R U D E   O I L   &   F U E L   O I L   P R I C E S

B A S E   C A S E   S C E N A R I O

APRIL 5, 1991

	C R U D E O I L P R I C E							
	ARABIAN LIGHT				U.S. REFINER'S ACQUISITION COST			
	$/BBL		$/MMBTU		$/BBL		$/MMBTU	
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL
1991	$18.76	$18.76	$3.22	$3.22	$20.26	$20.26	$3.48	$3.48
1992	$21.16	$21.82	$3.63	$3.74	$22.61	$23.32	$3.88	$4.00
1993	$23.60	$25.06	$4.05	$4.30	$25.01	$26.56	$4.29	$4.56
1994	$25.98	$28.39	$4.46	$4.87	$27.35	$29.89	$4.69	$5.13
1995	$28.15	$31.81	$4.83	$5.46	$29.48	$33.31	$5.06	$5.71
1996	$30.00	$35.12	$5.15	$6.02	$31.28	$36.62	$5.37	$6.28
1997	$31.60	$38.32	$5.42	$6.57	$32.84	$39.82	$5.63	$6.83
1998	$32.95	$41.40	$5.65	$7.10	$34.14	$42.90	$5.86	$7.36
1999	$34.05	$44.32	$5.84	$7.60	$35.20	$45.82	$6.04	$7.86
2000	$34.95	$47.17	$5.99	$8.09	$36.06	$48.67	$6.19	$8.35
2001	$35.75	$50.14	$6.13	$8.60	$36.82	$51.64	$6.32	$8.86
2002	$36.40	$53.14	$6.24	$9.11	$37.43	$54.64	$6.42	$9.37
2003	$36.90	$56.13	$6.33	$9.63	$37.89	$57.63	$6.50	$9.89
2004	$37.40	$59.28	$6.42	$10.17	$38.35	$60.78	$6.58	$10.43
2005	$37.80	$62.49	$6.48	$10.72	$38.71	$63.99	$6.64	$10.98
2006	$38.10	$65.70	$6.54	$11.27	$38.97	$67.20	$6.68	$11.53
2007	$38.40	$69.06	$6.59	$11.85	$39.23	$70.56	$6.73	$12.10
2008	$38.60	$72.48	$6.62	$12.43	$39.40	$73.98	$6.76	$12.59
2009	$38.75	$75.96	$6.65	$13.03	$39.52	$77.46	$6.78	$13.29
2010	$38.90	$79.53	$6.67	$13.64	$39.63	$81.03	$6.80	$13.90
2011	$39.05	$83.27	$6.70	$14.28	$39.75	$84.77	$6.82	$14.54
2012	$39.20	$87.19	$6.72	$14.95	$39.87	$88.69	$6.84	$15.21
2013	$39.30	$91.25	$6.74	$15.65	$39.95	$92.75	$6.85	$15.91
2014	$39.40	$95.60	$6.76	$16.40	$40.02	$97.10	$6.86	$16.66
2015	$39.50	$100.16	$6.78	$17.18	$40.09	$101.66	$6.88	$17.44
2016	$39.60	$104.93	$6.79	$18.00	$40.17	$106.43	$6.89	$18.26
2017	$39.70	$109.93	$6.81	$18.86	$40.24	$111.43	$6.90	$19.11
2018	$39.80	$115.17	$6.83	$19.75	$40.32	$116.67	$6.92	$20.01
2019	$39.85	$120.50	$6.84	$20.67	$40.35	$122.00	$6.92	$20.93
2020	$39.90	$126.08	$6.84	$21.63	$40.37	$127.58	$6.93	$21.88

	DISTILLATE FUEL OIL				1.0% S RESIDUAL FUEL OIL @ US GULF COAST			
	$/BBL		$/MMBTU		$/BBL		$/MMBTU	
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL
1991	$22.76	$22.76	$3.90	$3.90	$14.83	$14.83	$2.33	$2.33
1992	$27.77	$28.60	$4.76	$4.91	$19.83	$20.44	$3.12	$3.21
1993	$30.87	$32.72	$5.30	$5.61	$22.11	$23.48	$3.48	$3.69
1994	$33.92	$36.97	$5.82	$6.34	$24.39	$26.65	$3.83	$4.19
1995	$36.80	$41.45	$6.31	$7.11	$26.54	$29.98	$4.17	$4.71
1996	$39.03	$45.52	$6.70	$7.81	$28.20	$33.01	$4.43	$5.19
1997	$42.00	$50.75	$7.20	$8.71	$30.34	$36.79	$4.77	$5.78
1998	$43.94	$55.02	$7.54	$9.44	$31.76	$39.91	$4.99	$6.27
1999	$45.57	$59.12	$7.82	$10.14	$32.96	$42.90	$5.18	$6.75
2000	$49.78	$67.00	$8.54	$11.49	$35.86	$48.40	$5.64	$7.61
2001	$51.32	$71.77	$8.80	$12.31	$36.97	$51.84	$5.81	$8.15
2002	352.82	$75.90	$9.06	$13.19	$37.93	$55.37	$5.96	$8.71
2003	$54.12	$82.10	$9.28	$14.08	$38.75	$58.94	$6.09	$9.27
2004	$55.36	$87.52	$9.50	$15.01	$39.53	$62.66	$6.22	$9.85
2005	$56.47	$93.12	$9.69	$15.97	$40.22	$66.49	$6.32	$10.45
2006	$57.44	$98.80	$9.85	$16.95	$40.81	$70.36	$6.42	$11.06
2007	$58.34	$104.67	$10.01	$17.95	$41.36	$74.38	$6.50	$11.69
2008	$59.10	$110.71	$10.14	$18.99	$41.80	$78.49	$6.57	$12.34
2009	$59.72	$116.78	$10.24	$20.03	$42.14	$82.64	$6.63	$12.99
2010	$60.25	$122.90	$10.33	$21.08	$42.48	$86.85	$6.68	$13.66
2011	$60.72	$129.17	$10.41	$22.16	$42.76	$91.18	$6.72	$14.34
2012	$61.10	$135.58	$10.48	$23.26	$43.00	$95.64	$6.76	$15.04
2013	$61.33	$142.08	$10.52	$24.37	$43.15	$100.20	$6.78	$15.75
2014	$61.48	$148.85	$10.55	$25.53	$43.26	$104.97	$6.80	$16.51
2015	$61.56	$155.73	$10.56	$26.71	$43.33	$109.87	$6.81	$17.28
2016	$61.55	$162.73	$10.56	$27.91	$43.36	$114.90	$6.82	$18.07
2017	$61.47	$169.81	$10.54	$29.13	$43.35	$120.04	$6.82	$18.87
2018	$61.30	$176.97	$10.51	$30.36	$43.30	$125.30	$6.81	$19.70
2019	$60.98	$183.96	$10.46	$31.55	$43.16	$130.50	$6.79	$20.52
2020	$60.57	$190.84	$10.39	$32.73	$42.97	$135.79	$6.76	$21.35

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED CONSTANT 1991 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU

BASE CASE SCENARIO

APRIL 5, 1991

YEAR	0.3% SULFUR FUEL OIL $/BBL 1991$	$/BBL NOMINAL	$/MMBTU 1991$	$/MMBTU NOMINAL	0.7% SULFUR FUEL OIL $/BBL 1991$	$/BBL NOMINAL	$/MMBTU 1991$	$/MMBTU NOMINAL
1991	$18.50	$18.50	$2.90	$2.90	$16.71	$16.71	$2.62	$2.62
1992	$24.38	$25.10	$3.82	$3.93	$21.94	$22.59	$3.44	$3.55
1993	$27.11	$28.73	$4.25	$4.50	$24.33	$25.77	$3.82	$4.05
1994	$29.86	$32.54	$4.68	$5.10	$26.73	$29.11	$4.20	$4.57
1995	$32.50	$36.59	$5.09	$5.73	$28.98	$32.61	$4.55	$5.12
1996	$34.54	$40.25	$5.41	$6.31	$30.71	$35.78	$4.82	$5.62
1997	$37.15	$44.87	$5.82	$7.03	$32.95	$39.78	$5.17	$6.25
1998	$38.94	$48.73	$6.10	$7.64	$34.45	$43.09	$5.41	$6.77
1999	$40.46	$52.47	$6.34	$8.22	$35.71	$46.28	$5.61	$7.27
2000	$44.02	$59.22	$6.90	$9.28	$38.74	$52.10	$6.08	$8.18
2001	$45.45	$63.54	$7.12	$9.96	$39.91	$55.76	$6.26	$8.75
2002	$46.72	$67.99	$7.32	$10.66	$40.92	$59.53	$6.42	$9.34
2003	$47.81	$72.51	$7.49	$11.37	$41.78	$63.33	$6.56	$9.94
2004	$48.88	$77.25	$7.66	$12.11	$42.60	$67.31	$6.69	$10.57
2005	$49.83	$82.14	$7.81	$12.87	$43.33	$71.40	$6.80	$11.21
2006	$50.66	$87.11	$7.94	$13.65	$43.95	$75.53	$6.90	$11.86
2007	$51.45	$92.28	$8.06	$14.46	$44.53	$79.83	$6.99	$12.53
2008	$52.12	$97.59	$8.17	$15.30	$45.00	$84.23	$7.06	$13.22
2009	$52.68	$102.99	$8.26	$16.14	$45.38	$88.67	$7.12	$13.92
2010	$53.20	$108.47	$8.34	$17.00	$45.72	$93.18	$7.18	$14.63
2011	$53.67	$114.14	$8.41	$17.89	$46.02	$97.82	$7.22	$15.36
2012	$54.10	$120.00	$8.48	$18.81	$46.27	$102.60	$7.26	$16.11
2013	$54.41	$126.01	$8.53	$19.75	$46.43	$107.49	$7.29	$16.87
2014	$54.67	$132.32	$8.57	$20.74	$46.55	$112.62	$7.31	$17.68
2015	$54.89	$138.83	$8.60	$21.76	$46.63	$117.88	$7.32	$18.51
2016	$55.06	$145.52	$8.63	$22.81	$46.67	$123.29	$7.33	$19.35
2017	$55.18	$152.39	$8.65	$23.89	$46.66	$128.82	$7.33	$20.22
2018	$55.24	$159.45	$8.66	$24.99	$46.61	$134.47	$7.32	$21.11
2019	$55.19	$166.47	$8.65	$26.09	$46.47	$140.08	$7.29	$21.99
2020	$55.09	$173.51	$8.63	$27.20	$46.28	$145.66	$7.26	$22.87

YEAR	1.0% SULFUR FUEL OIL $/BBL 1991$	$/BBL NOMINAL	$/MMBTU 1991$	$/MMBTU NOMINAL	1.5% SULFUR FUEL OIL $/BBL 1991$	$/BBL NOMINAL	$/MMBTU 1991$	$/MMBTU NOMINAL
1991	$16.03	$16.03	$2.52	$2.52	$15.29	$15.29	$2.41	$2.41
1992	$21.03	$21.65	$3.31	$3.40	$20.01	$20.60	$3.15	$3.24
1993	$23.31	$24.69	$3.67	$3.88	$22.15	$23.46	$3.49	$3.69
1994	$25.59	$27.87	$4.02	$4.38	$24.28	$26.44	$3.82	$4.16
1995	$27.74	$31.21	$4.36	$4.91	$26.28	$29.56	$4.14	$4.65
1996	$29.40	$34.24	$4.62	$5.38	$27.82	$32.39	$4.38	$5.10
1997	$31.54	$38.07	$4.96	$5.99	$29.21	$35.24	$4.60	$5.55
1998	$32.97	$41.23	$5.18	$6.48	$30.51	$38.15	$4.80	$6.01
1999	$34.16	$44.27	$5.37	$6.96	$31.59	$40.93	$4.98	$6.45
2000	$37.06	$49.83	$5.83	$7.83	$34.26	$46.05	$5.40	$7.25
2001	$38.17	$53.32	$6.00	$8.38	$35.25	$49.23	$5.55	$7.75
2002	$39.13	$56.92	$6.15	$8.95	$34.21	$49.73	$5.39	$7.83
2003	$39.95	$60.55	$6.28	$9.52	$34.92	$52.90	$5.50	$8.33
2004	$40.73	$64.34	$6.40	$10.12	$35.59	$56.19	$5.60	$8.85
2005	$41.42	$68.24	$6.51	$10.73	$36.18	$59.57	$5.70	$9.38
2006	$42.01	$72.19	$6.61	$11.35	$36.67	$62.98	$5.77	$9.92
2007	$42.56	$76.29	$6.69	$11.99	$37.12	$66.51	$5.85	$10.47
2008	$43.01	$80.48	$6.76	$12.65	$37.48	$70.11	$5.90	$11.04
2009	$43.36	$84.72	$6.82	$13.32	$37.76	$73.73	$5.95	$11.61
2010	$43.68	$89.02	$6.87	$14.00	$38.00	$77.40	$5.98	$12.19
2011	$43.96	$93.44	$6.91	$14.69	$38.20	$81.16	$6.02	$12.78
2012	$44.21	$98.00	$6.95	$15.41	$38.37	$85.03	$6.04	$13.39
2013	$44.35	$102.66	$6.97	$16.14	$38.46	$88.97	$6.06	$14.01
2014	$44.46	$107.55	$6.99	$16.91	$38.51	$93.09	$6.06	$14.66
2015	$44.53	$112.57	$7.00	$17.70	$38.52	$97.31	$6.07	$15.32
2016	$44.56	$117.71	$7.01	$18.51	$38.49	$101.62	$6.06	$16.00
2017	$44.56	$122.98	$7.01	$19.34	$38.43	$106.03	$6.05	$16.70
2018	$44.51	$128.37	$7.00	$20.18	$38.34	$110.52	$6.04	$17.40
2019	$44.36	$133.71	$6.97	$21.02	$38.15	$114.95	$6.01	$18.10
2020	$44.18	$139.02	$6.95	$21.86	$37.94	$119.31	$5.97	$18.79

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED CONSTANT 1991 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU & NATURAL GAS
AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

APRIL 5, 1991

BASE CASE SCENARIO

YEAR	INTERRUPTIBLE SERVICE PI GAS $/MMBTU 1991$	PI GAS NOMINAL	INTERRUPTIBLE SPOT GAS $/MMBTU 1991$	SPOT GAS NOMINAL	INTERRUPTIBLE AVERAGE $/MMBTU NOMINAL	FIRM SERVICE SPOT GAS $/MMBTU 1991$	SPOT GAS NOMINAL	FIRM CITRUS GAS $/MMBTU 1991$	CITRUS GAS NOMINAL	FIRM AVERAGE $/MMBTU NOMINAL	SYSTEM WEIGHTED AVERAGE GAS PRICE $/MMBTU 1991$	SYSTEM WEIGHTED NOMINAL
1991	$2.20	$2.20	$1.89	$1.89	$2.05	$1.94	$1.94	$2.31	$2.31	$2.25	$2.21	$2.21
1992	$2.99	$3.07	$2.33	$2.39	$2.73	$2.38	$2.45	$3.08	$3.16	$3.00	$2.86	$2.94
1993	$3.33	$3.53	$2.96	$3.14	$3.35	$3.01	$3.19	$3.38	$3.58	$3.53	$3.30	$3.49
1994	$3.68	$4.01	$3.53	$3.84	$3.93	$3.58	$3.90	$3.73	$4.07	$4.06	$3.71	$4.04
1995	$4.00	$4.50	$3.94	$4.43	$4.48	$3.99	$4.49	$4.03	$4.54	$4.54	$4.03	$4.53
1996	$4.25	$4.98	$4.19	$4.90	$4.94	$4.25	$4.97	$4.25	$4.98	$4.98	$4.25	$4.97
1997	$4.57	$5.55	$4.53	$5.50	$5.52	$4.59	$5.57	$4.57	$5.55	$5.55	$4.57	$5.54
1998	$4.79	$6.02	$4.78	$6.01	$6.01	$4.84	$6.08	$4.79	$6.02	$6.02	$4.79	$6.02
1999	$4.97	$6.47	$5.00	$6.51	$6.47	$5.06	$6.58	$4.91	$6.40	$6.40	$4.92	$6.41
2000	$5.41	$7.30	$5.81	$7.84	$7.84	$5.87	$7.93	$4.93	$6.65	$6.65	$5.09	$6.87
2001	$5.57	$7.82	$5.99	$8.40	$8.40						$5.99	$8.40
2002	$5.72	$8.35	$6.05	$8.84	$8.84						$6.05	$8.84
2003	$5.84	$8.89	$6.23	$9.48	$9.48						$6.23	$9.48
2004			$6.41	$10.17	$10.17						$6.41	$10.17
2005			$6.58	$10.88	$10.88						$6.58	$10.88
2006			$6.75	$11.64	$11.64						$6.75	$11.64
2007			$6.91	$12.43	$12.43						$6.91	$12.43
2008			$7.07	$13.27	$13.27						$7.07	$13.27
2009			$7.21	$14.14	$14.14						$7.21	$14.14
2010			$7.37	$15.06	$15.06						$7.37	$15.06
2011			$7.51	$16.02	$16.02						$7.51	$16.02
2012			$7.67	$17.06	$17.06						$7.67	$17.06
2013			$7.82	$18.15	$18.15						$7.82	$18.15
2014			$7.96	$19.32	$19.32						$7.96	$19.32
2015			$8.10	$20.55	$20.55						$8.10	$20.55
2016			$8.24	$21.85	$21.85						$8.24	$21.85
2017			$8.38	$23.20	$23.20						$8.38	$23.20
2018			$8.50	$24.60	$24.60						$8.50	$24.60
2019			$8.61	$26.03	$26.03						$8.61	$26.03
2020			$8.71	$27.51	$27.51						$8.71	$27.51

YEAR	NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY INTERRUPTIBLE SERVICE PI	INTERRUPTIBLE SPOT	INTERRUPTIBLE TOTAL	FIRM SERVICE SPOT	FIRM SERVICE CITRUS	FIRM SERVICE TOTAL	TOTAL FPL SYSTEM	SPOT/MARKET GAS @ USGC $/MMBTU 1991$	SPOT/MARKET NOMINAL	TRANSPORTATION SERVICE INTERRUPTIBLE $/MMBTU 1991$	INTERRUPTIBLE NOMINAL	TRANSPORTATION SERVICE FIRM $/MMBTU 1991$	FIRM NOMINAL
1991	35	35	70	50	264	314	384	$1.56	$1.56	$0.33	$0.33	$0.38	$0.38
1992	47	47	94	73	259	332	426	$1.99	$2.04	$0.34	$0.35	$0.39	$0.40
1993	32	28	60	42	290	332	393	$2.61	$2.77	$0.35	$0.37	$0.40	$0.42
1994	34	30	64	29	303	332	396	$3.17	$3.46	$0.36	$0.39	$0.41	$0.44
1995	33	13	46	22	310	332	378	$3.58	$4.02	$0.36	$0.41	$0.41	$0.46
1996	27	26	53	22	310	332	385	$3.84	$4.49	$0.35	$0.42	$0.41	$0.48
1997	32	31	63	0	332	332	395	$4.17	$5.06	$0.36	$0.43	$0.42	$0.51
1998	34	33	67	0	332	332	399	$4.42	$5.55	$0.36	$0.46	$0.42	$0.53
1999	69	0	69	0	332	332	401	$4.64	$6.04	$0.37	$0.48	$0.42	$0.55
2000	0	74	74	0	332	332	406	$5.44	$7.34	$0.37	$0.50	$0.43	$0.59
2001	0	398	398	0	0	0	398	$5.61	$7.87	$0.38	$0.53		
2002	0	398	398	0	0	0	398	$5.81	$8.49	$0.24	$0.35		
2003	0	397	397	0	0	0	397	$6.00	$9.13	$0.23	$0.36		
2004		397	397	0	0	0	397	$6.18	$9.80	$0.23	$0.37		
2005		404	404				404	$6.36	$10.51	$0.23	$0.37		
2006		396	396				396	$6.52	$11.25	$0.22	$0.39		
2007		405	405				405	$6.69	$12.03	$0.22	$0.40		
2008		405	405				405	$6.85	$12.86	$0.22	$0.41		
2009		405	405				405	$7.00	$13.72	$0.21	$0.42		
2010		405	405				405	$7.15	$14.62	$0.21	$0.43		
2011		405	405				405	$7.30	$15.57	$0.21	$0.45		
2012		405	405				405	$7.46	$16.60	$0.21	$0.46		
2013		405	405				405	$7.61	$17.68	$0.20	$0.48		
2014		405	405				405	$7.76	$18.83	$0.20	$0.49		
2015		405	405				405	$7.90	$20.04	$0.20	$0.51		
2016		405	405				405	$8.05	$21.32	$0.20	$0.53		
2017		405	405				405	$8.18	$22.65	$0.20	$0.55		
2018		405	405				405	$8.31	$24.04	$0.20	$0.57		
2019		405	405				405	$8.41	$25.44	$0.19	$0.59		
2020		405	405				405	$8.51	$26.90	$0.19	$0.61		

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

D E L I V E R E D   C O N S T A N T   1 9 9 1   D O L L A R   &   N O M I N A L   D O L L A R   C O A L   P R I C E S   I N   D O L L A R S   P E R   T O N   &
P E R   M M B T U
B A S E   C A S E   S C E N A R I O

APRIL 5, 1991

	ST. JOHNS RIVER POWER PARK (WEIGHTED AVERAGE PRICE)				ST. JOHNS RIVER POWER PARK (SPOT/SHORT-TERM CONTRACT PRICE)			
	------$/TON------		------$/MMBTU------		------$/TON------		------$/MMBTU------	
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL
1991	$44.77	$44.77	$1.84	$1.84	$41.15	$41.15	$1.71	$1.71
1992	$42.19	$43.46	$1.74	$1.79	$40.87	$42.33	$1.70	$1.76
1993	$42.60	$45.19	$1.75	$1.86	$41.09	$44.10	$1.71	$1.84
1994	$43.33	$47.40	$1.78	$1.94	$41.33	$46.04	$1.72	$1.92
1995	$43.96	$49.87	$1.80	$2.04	$41.44	$48.11	$1.73	$2.00
1996	$44.74	$52.73	$1.83	$2.16	$41.55	$50.31	$1.73	$2.10
1997	$43.79	$53.61	$1.83	$2.24	$41.70	$52.65	$1.74	$2.19
1998	$44.15	$56.17	$1.85	$2.35	$41.76	$55.00	$1.74	$2.29
1999	$43.59	$57.56	$1.82	$2.40	$41.57	$57.07	$1.73	$2.38
2000	$43.70	$60.02	$1.82	$2.50	$40.76	$58.41	$1.70	$2.43
2001	$43.87	$62.72	$1.83	$2.61	$40.86	$61.08	$1.70	$2.55
2002	$43.50	$64.87	$1.81	$2.70	$40.67	$63.56	$1.69	$2.65
2003	$42.35	$65.87	$1.76	$2.74	$41.53	$73.12	$1.73	$2.82
2004	$42.15	$68.38	$1.76	$2.85	$41.41	$76.01	$1.73	$2.93
2005	$42.03	$71.17	$1.75	$2.97	$41.54	$79.52	$1.73	$3.07
2006	$41.91	$74.09	$1.75	$3.09	$41.68	$83.21	$1.74	$3.21
2007	$42.61	$78.73	$1.78	$3.28	$41.82	$87.17	$1.74	$3.37
2008	$42.49	$82.03	$1.77	$3.42	$41.97	$91.31	$1.75	$3.53
2009	$42.37	$85.57	$1.77	$3.57	$42.12	$95.76	$1.76	$3.70
2010	$42.33	$89.33	$1.76	$3.72	$42.53	$100.88	$1.77	$3.91
2011	$43.44	$95.81	$1.81	$3.99	$42.69	$105.72	$1.78	$4.10
2012	$43.33	$99.96	$1.81	$4.16	$42.86	$110.90	$1.79	$4.30
2013	$43.29	$104.65	$1.80	$4.36	$43.28	$117.17	$1.80	$4.55
2014	$43.18	$109.51	$1.80	$4.56	$43.44	$123.27	$1.81	$4.79
2015	$44.58	$118.59	$1.86	$4.94	$43.87	$130.38	$1.83	$5.07
2016	$44.47	$124.10	$1.85	$5.17	$44.04	$137.20	$1.84	$5.34
2017	$44.43	$130.07	$1.85	$5.42	$44.48	$145.13	$1.85	$5.65
2018	$44.39	$136.32	$1.85	$5.68	$44.87	$153.38	$1.87	$5.98
2019	$45.89	$147.84	$1.91	$6.16	$45.22	$161.98	$1.88	$6.31
2020	$45.85	$154.93	$1.91	$6.46	$45.63	$171.21	$1.90	$6.68

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLAR PRICES.

D E L I V E R E D   N O M I N A L   D O L L A R   C O A L   P R I C E S   I N   D O L L A R S   P E R   T O N   &   P E R
M M B T U
B A S E   C A S E   S C E N A R I O
APRIL 5, 1991

HIGH SULFUR COAL PROCUREMENT STRATEGY FORECAST
FOR THE MARTIN SITE
NOMINAL DOLLARS (12,000 BTU/LB)

YEAR	---MINEMOUTH--- $/MMBTU	$/TON	-TRANSPORTATION- $/MMBTU	$/TON	---DELIVERED--- $/MMBTU	$/TON
1991	$0.96	$23.00	$0.92	$22.19	$1.88	$45.19
1992	$0.97	$23.22	$1.02	$24.43	$1.99	$47.65
1993	$1.00	$24.09	$1.08	$26.03	$2.09	$50.12
1994	$1.04	$25.02	$1.15	$27.64	$2.19	$52.66
1995	$1.09	$26.14	$1.22	$29.39	$2.31	$55.53
1996	$1.13	$27.05	$1.27	$30.54	$2.40	$57.60
1997	$1.17	$28.03	$1.32	$31.78	$2.49	$59.82
1998	$1.21	$29.05	$1.38	$33.01	$2.59	$62.06
1999	$1.25	$29.97	$1.43	$34.23	$2.68	$64.20
2000	$1.28	$30.73	$1.49	$35.72	$2.77	$66.45
2001	$1.33	$31.90	$1.55	$37.13	$2.88	$69.03
2002	$1.39	$33.27	$1.61	$38.67	$3.00	$71.94
2003	$1.44	$34.53	$1.68	$40.27	$3.12	$74.80
2004	$1.50	$35.91	$1.75	$41.93	$3.24	$77.84
2005	$1.56	$37.48	$1.82	$43.70	$3.38	$81.18
2006	$1.63	$39.13	$1.90	$45.53	$3.53	$84.67
2007	$1.77	$42.48	$1.98	$47.49	$3.75	$89.96
2008	$1.85	$44.37	$2.06	$49.52	$3.91	$93.90
2009	$1.93	$46.40	$2.15	$51.69	$4.09	$98.09
2010	$2.03	$48.62	$2.25	$53.90	$4.27	$102.52
2011	$2.23	$53.59	$2.34	$56.21	$4.58	$109.80
2012	$2.33	$56.02	$2.44	$58.67	$4.78	$114.70
2013	$2.45	$58.84	$2.56	$61.35	$5.01	$120.18
2014	$2.57	$61.69	$2.68	$64.20	$5.25	$125.89
2015	$2.87	$68.83	$2.80	$67.19	$5.67	$136.02
2016	$3.01	$72.14	$2.93	$70.32	$5.94	$142.46
2017	$3.16	$75.80	$3.07	$73.60	$6.22	$149.40
2018	$3.32	$79.63	$3.21	$77.03	$6.53	$156.66
2019	$3.70	$88.83	$3.36	$80.61	$7.06	$169.44
2020	$3.89	$93.26	$3.52	$84.36	$7.40	$177.62

EASTERN COMPLIANCE COAL PROCUREMENT STRATEGY FORECAST
FOR SCHERER UNIT NO. 4
NOMINAL DOLLARS (12,000 BTU/LB)

YEAR	---MINEMOUTH--- $/MMBTU	$/TON	-TRANSPORTATION- $/MMBTU	$/TON	---DELIVERED--- $/MMBTU	$/TON
1991	$1.38	$33.11	$0.50	$11.93	$1.88	$45.04
1992	$1.41	$33.91	$0.51	$12.16	$1.92	$46.08
1993	$1.44	$34.53	$0.54	$12.97	$1.98	$47.50
1994	$1.47	$35.30	$0.56	$13.39	$2.03	$48.69
1995	$1.52	$36.44	$0.58	$13.87	$2.10	$50.32
1996	$1.56	$37.55	$0.61	$14.57	$2.17	$52.12
1997	$1.58	$37.92	$0.65	$15.61	$2.23	$53.53
1998	$1.61	$38.76	$0.66	$15.74	$2.27	$54.50
1999	$1.79	$42.88	$0.68	$16.36	$2.47	$59.24
2000	$1.89	$45.24	$0.71	$17.09	$2.60	$62.33
2001	$1.97	$47.21	$0.74	$17.80	$2.71	$65.01
2002	$2.05	$49.27	$0.77	$18.56	$2.83	$67.83
2003	$2.34	$56.19	$0.81	$19.37	$3.15	$75.[illegible]
2004	$2.44	$58.49	$0.84	$20.21	$3.28	$78.70
2005	$2.55	$61.25	$0.88	$21.11	$3.43	$82.35
2006	$2.67	$63.96	$0.92	$22.03	$3.58	$86.00
2007	$2.92	$70.02	$0.96	$23.02	$3.88	$93.05
2008	$3.05	$73.19	$1.00	$24.06	$4.05	$97.26
2009	$3.14	$75.41	$0.97	$23.26	$4.11	$98.67
2010	$3.29	$79.05	$1.01	$24.27	$4.30	$103.32
2011	$3.67	$88.15	$1.06	$25.32	$4.73	$113.47
2012	$3.84	$92.27	$1.10	$26.44	$4.95	$118.71
2013	$4.04	$96.91	$1.15	$27.66	$5.19	$124.57
2014	$4.24	$101.72	$1.21	$28.96	$5.45	$130.68
2015	$4.77	$114.47	$1.26	$30.32	$6.03	$144.79
2016	$5.01	$120.15	$1.32	$31.74	$6.33	$151.89
2017	$5.26	$126.30	$1.38	$33.23	$6.65	$159.53
2018	$5.53	$132.71	$1.45	$34.79	$6.98	$167.50
2019	$6.24	$149.72	$1.52	$36.42	$7.76	$186.14
2020	$6.56	$157.38	$1.59	$38.12	$8.15	$195.51

WESTERN COMPLIANCE COAL PROCUREMENT STRATEGY FORECAST
FOR SCHERER UNIT NO. 4
NOMINAL DOLLARS (8,500 BTU/LB)

YEAR	----MINEMOUTH--- $/MMBTU	$/TON	-TRANSPORTATION- $/MMBTU	$/TON	---DELIVERED--- $/MMBTU	$/TON
1991	$1.64	$28.45				
1992	$1.67	$28.93				
1993	$1.70	$29.43				
1994	$1.71	$29.62				
1995	$1.82	$31.50				
1996	$1.96	$33.88				
1997	$2.01	$34.66				
1998	$2.06	$35.54				
1999	$2.10	$36.19				
2000	$2.15	$36.95				
2001	$2.47	$42.43				
2002	$2.56	$44.02				
2003	$2.68	$46.05				
2004	$2.79	$47.82				
2005	$2.90	$49.78				
2006	$3.01	$51.69				
2007	$3.15	$53.92				
2008	$3.27	$56.07				
2009	$3.36	$57.15				
2010	$3.50	$59.57				
2011	$3.67	$62.[illegible]				
2012	$3.83	$65.[illegible]				
2013	$4.00	$68.01				
2014	$4.19	$71.16				
2015	$4.39	$74.69				
2016	$4.60	$78.14				
2017	$4.81	$81.76				
2018	$5.03	$85.55				
2019	$5.28	$89.72				
2020	$5.52	$91.89				

1991 TO 2020 LONG-TERM FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLAR PRICES.

D E L I V E R E D   N O M I N A L   D O L L A R   O R I M U L S I O N   P R I C E S   I N   D O L L A R S   P E R   T O N   &   P E R   M M B T U

B A S E   C A S E   S C E N A R I O

APRIL 5, 1991

NOMINAL DOLLARS

YEAR	SANFORD $/MMBTU	PORT EVERGLADES $/MMBTU	MANATEE $/MMBTU	CAPE CANAVERAL $/MMBTU	MARTIN $/MMBTU
1991	$2.09	$1.92	$1.92	$1.97	$1.92
1992	$2.03	$1.87	$1.86	$1.91	$1.87
1993	$2.10	$1.94	$1.93	$1.98	$1.94
1994	$2.19	$2.03	$2.02	$2.07	$2.03
1995	$2.29	$2.13	$2.12	$2.17	$2.12
1996	$2.41	$2.25	$2.24	$2.29	$2.24
1997	$2.50	$2.33	$2.33	$2.38	$2.33
1998	$2.61	$2.44	$2.44	$2.49	$2.44
1999	$2.66	$2.49	$2.49	$2.54	$2.49
2000	$2.76	$2.60	$2.59	$2.64	$2.60
2001	$2.88	$2.71	$2.71	$2.76	$2.71
2002	$2.97	$2.81	$2.80	$2.85	$2.80
2003	$3.01	$2.85	$2.84	$2.89	$2.85
2004	$3.12	$2.96	$2.95	$3.00	$2.95
2005	$3.24	$3.07	$3.07	$3.12	$3.07
2006	$3.36	$3.20	$3.19	$3.24	$3.20
2007	$3.56	$3.40	$3.39	$3.44	$3.39
2008	$3.70	$3.54	$3.53	$3.58	$3.53
2009	$3.85	$3.69	$3.68	$3.73	$3.69
2010	$4.01	$3.85	$3.84	$3.89	$3.85
2011	$4.29	$4.12	$4.12	$4.17	$4.12
2012	$4.47	$4.30	$4.29	$4.35	$4.30
2013	$4.67	$4.50	$4.49	$4.54	$4.50
2014	$4.87	$4.71	$4.70	$4.75	$4.71
2015	$5.26	$5.09	$5.09	$5.14	$5.09
2016	$5.49	$5.33	$5.32	$5.37	$5.33
2017	$5.75	$5.58	$5.58	$5.63	$5.58
2018	$6.01	$5.85	$5.84	$5.89	$5.85
2019	$6.51	$6.34	$6.33	$6.39	$6.34
2020	$6.81	$6.64	$6.64	$6.69	$6.64

NOMINAL DOLLARS

SANFORD $/TON	PORT EVERGLADES $/TON	MANATEE $/TON	CAPE CANAVERAL $/TON	MARTIN $/TON
$53.48	$49.27	$49.06	$50.40	$49.21
$52.07	$47.86	$47.65	$48.99	$47.80
$53.84	$49.62	$49.42	$50.75	$49.57
$56.11	$51.89	$51.69	$53.02	$51.84
$58.66	$54.44	$54.24	$55.57	$54.39
$61.72	$57.50	$57.30	$58.63	$57.45
$63.97	$59.75	$59.55	$60.88	$59.70
$66.77	$62.55	$62.35	$63.69	$62.50
$68.06	$63.85	$63.64	$64.98	$63.79
$70.75	$66.53	$66.33	$67.66	$66.48
$73.69	$69.48	$69.27	$70.61	$69.43
$76.04	$71.82	$71.62	$72.95	$71.77
$77.12	$72.91	$72.70	$74.04	$72.86
$79.87	$75.65	$75.45	$76.78	$75.60
$82.91	$78.70	$78.49	$79.83	$78.65
$86.10	$81.88	$81.68	$83.01	$81.83
$91.15	$86.94	$86.73	$88.07	$86.88
$94.76	$90.55	$90.34	$91.68	$90.49
$98.62	$94.40	$94.20	$95.54	$94.35
$102.73	$98.51	$98.30	$99.64	$98.46
$109.79	$105.57	$105.37	$106.70	$105.52
$114.32	$110.10	$109.90	$111.23	$110.05
$119.43	$115.22	$115.01	$116.35	$115.16
$124.73	$120.52	$120.31	$121.65	$120.47
$134.64	$130.43	$130.22	$131.56	$130.37
$140.65	$136.43	$136.23	$137.56	$136.38
$147.17	$142.95	$142.74	$144.08	$142.90
$153.98	$149.77	$149.56	$150.90	$149.71
$166.56	$162.34	$162.13	$163.47	$162.29
$174.29	$170.07	$169.87	$171.20	$170.02

FPL

Inter-Office Correspondence

To: Distribution

Date: February 20, 1992

From: C.O. Woody/A. J. Olivera

Department: EX - G.O.

Subject: **FPL Short-Term (1992-1994)/ Data Resources, Inc. (DRI) Base Case Long-Term (1995-2021) Fossil Fuel Price Forecast**

Attached is the current short and long-term fossil fuel price forecast for crude oil, residual and distillate fuel oil, natural gas, coal, and Orimulsion, as well as the current projection for natural gas availability. This forecast represents the combination of the current FPL short-term fossil fuel price forecast through 1994, and the DRI fourth quarter, 1991 long-term fossil fuel price forecast for 1995 and beyond. For planning purposes, this forecast supersedes the November 5, 1991 FPL short-term fossil fuel price forecast and the memorandum of January 15, 1992, which issued the DRI fourth quarter, 1991 long-term fossil fuel price forecast.

A. J. Olivera
Vice President
Planning & Resource Allocation

C. ~~O.~~ Woody
Sr. Vice President
Power Generation

AJO:pre
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Form 1008 (Stocked) Rev. 5/89

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	***CRUDE OIL*** ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	WTI FIRST FORWARD MONTH FUTURE'S PRICE	***DISTILLATE FUEL OIL*** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN 92	$15.08	$16.58	$18.08	$22.41	$22.62	$22.36	$22.84
FEB	$15.37	$16.87	$18.37	$21.48	$21.69	$21.44	$21.91
MAR	$15.15	$16.65	$18.15	$21.25	$21.46	$21.20	$21.68
APR92	$14.93	$16.43	$17.93	$20.01	$20.23	$19.97	$20.45
MAY92	$14.71	$16.21	$17.71	$19.05	$19.26	$19.00	$19.48
JUN	$15.77	$17.27	$18.77	$20.84	$21.06	$20.80	$21.28
JULY	$16.82	$18.32	$19.82	$22.19	$22.40	$22.14	$22.62
AUG	$17.88	$19.38	$20.88	$24.06	$24.27	$24.01	$24.49
SEP192	$17.41	$18.91	$20.41	$23.91	$24.13	$23.87	$24.35
OCT92	$18.48	$19.98	$21.48	$26.23	$26.44	$26.18	$26.67
NOV	$19.55	$21.05	$22.55	$28.24	$28.45	$28.19	$28.68
DEC	$20.63	$22.13	$23.63	$31.41	$31.62	$31.36	$31.85
JAN93	$18.61	$20.11	$21.61	$27.70	$27.92	$27.65	$28.14
FEB	$17.61	$19.11	$20.61	$24.79	$25.01	$24.75	$25.24
MAR	$16.88	$18.38	$19.88	$23.87	$24.09	$23.82	$24.32
APR93	$16.39	$17.89	$19.39	$22.19	$22.41	$22.15	$22.64
MAY 93	$15.91	$17.41	$18.91	$20.83	$21.05	$20.79	$21.28
JUN	$16.99	$18.49	$19.99	$22.73	$22.95	$22.68	$23.18
JUL	$18.34	$19.84	$21.34	$24.47	$24.69	$24.42	$24.92
AUG	$19.43	$20.93	$22.43	$26.45	$26.67	$26.41	$26.90
SEP93	$18.69	$20.19	$21.69	$25.99	$26.21	$25.94	$26.44
OCT93	$19.26	$20.76	$22.26	$27.72	$27.94	$27.67	$28.17
NOV	$20.37	$21.87	$23.37	$29.82	$30.05	$29.78	$30.28
DEC	$21.48	$22.98	$24.48	$33.13	$33.36	$33.08	$33.59
1992	$16.82	$18.32	$19.82	$23.42	$23.64	$23.38	$23.86
1993	$18.33	$19.83	$21.33	$25.81	$26.03	$25.76	$26.26
1994	$20.48	$21.98	$23.48	$28.70	$28.92	$28.65	$29.16
1995	$23.25	$24.56	$26.06	$32.09	$32.32	$32.04	$32.56
1996	$25.90	$26.40	$28.67	$34.19	$34.43	$34.14	$34.68

DELIVERED RESIDUAL FUEL OIL

DATE	*0.7%* MARTIN	***1.0% SULFUR RESIDUAL FUEL OIL*** CANAVERAL	EVERGLADES	FT MYERS	MANATEE	SANFORD	TURKEY POINT	RIVIERA	***1.5% RESIDUAL*** RIVIERA	CANAVERAL	SANFORD	FT MYERS	***3.0%*** EVERGLADES	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
JAN92	$12.8[illegible]	$12.41	$12.23	$12.09	$11.94	$12.76	$12.16	$12.36	$11.80	$11.84	$12.20	$11.53	$9.49	$11.00
FEB	$13.50	$13.01	$12.84	$12.70	$12.54	$13.37	$12.76	$12.96	$12.37	$12.42	$12.77	$12.10	$9.96	$11.60
MAR	$13.96	$13.45	$13.28	$13.13	$12.98	$13.81	$13.20	$13.40	$12.78	$12.83	$13.19	$12.52	$10.27	$12.04
APR92	$13.77	$13.27	$13.10	$12.96	$12.80	$13.63	$13.02	$13.22	$12.62	$12.66	$13.02	$12.35	$10.13	$11.86
MAY92	$13.72	$13.23	$13.05	$12.91	$12.75	$13.59	$12.98	$13.18	$12.57	$12.62	$12.98	$12.31	$10.10	$11.81
JUN	$14.78	$14.23	$14.06	$13.92	$13.76	$14.59	$13.98	$14.19	$13.53	$13.58	$13.94	$13.26	$10.85	$12.82
JULY	$16.26	$15.65	$15.48	$15.33	$15.17	$16.01	$15.40	$15.60	$14.87	$14.92	$15.28	$14.60	$11.92	$14.23
AUG	$16.74	$16.11	$15.93	$15.79	$15.63	$16.47	$15.86	$16.06	$15.31	$15.35	$15.72	$15.04	$12.26	$14.69
SEP92	$15.97	$15.37	$15.20	$15.05	$14.89	$15.73	$15.12	$15.32	$14.61	$14.66	$15.02	$14.34	$11.71	$13.95
OC192	$17.27	$16.62	$1[illegible].44	$16.[illegible]0	$16.14	$16.98	$16.37	$16.57	$15.79	$15.84	$16.20	$15.52	$12.64	$15.20
NOV	$18.41	$17.71	$17.53	$17.39	$17.23	$18.07	$17.46	$17.66	$16.83	$16.88	$17.24	$16.55	$13.46	$16.29
DEC	$19.37	$18.63	$18.45	$18.31	$18.15	$18.99	$18.38	$18.58	$17.70	$17.75	$18.11	$17.43	$14.15	$17.21
JAN93	$19.00	$18.27	$18.10	$17.95	$17.79	$18.64	$18.02	$18.22	$17.34	$17.39	$17.75	$17.07	$13.88	$16.85
FEB	$18.05	$17.36	$17.18	$17.04	$16.87	$17.73	$17.10	$17.31	$16.4[illegible]	$16.52	$16.89	$16.20	$13.20	$15.94
MAR	$16.63	$16.00	$15.82	$15.68	$15.51	$16.37	$15.75	$15.95	$15.1[illegible]	$15.24	$15.60	$14.91	$12.18	$14.58
APR93	$16.19	$15.58	$15.40	$15.26	$15.09	$15.95	$15.32	$15.53	$14.79	$14.84	$15.20	$14.51	$11.86	$14.16
MAY93	$15.89	$15.30	$15.12	$14.97	$14.81	$15.67	$15.04	$15.25	$14.52	$14.57	$14.94	$14.25	$11.65	$13.87
JUN	$17.06	$16.42	$16.24	$16.09	$15.93	$16.79	$16.16	$16.37	$15.58	$15.63	$16.00	$15.31	$12.49	$14.99
JUL	$18.95	$18.22	$18.04	$17.89	$17.73	$18.59	$17.96	$18.17	$17.29	$17.34	$17.71	$17.01	$13.84	$16.79
AUG	$19.49	$18.74	$18.56	$18.41	$18.25	$19.11	$18.48	$18.69	$17.78	$17.83	$18.20	$17.51	$14.23	$17.31
SEP93	$18.41	$17.71	$17.52	$17.38	$17.21	$18.08	$17.45	$17.66	$16.80	$16.85	$17.22	$16.52	$13.46	$16.28
OC193	$19.36	$18.61	$18.43	$18.28	$18.12	$18.99	$18.35	$18.56	$17.66	$17.71	$18.08	$17.38	$14.13	$17.18
NOV	$20.62	$19.82	$19.63	$19.49	$19.32	$20.19	$19.56	$19.77	$18.80	$18.85	$19.23	$18.52	$15.04	$18.39
DEC	$21.69	$20.84	$20.66	$20.51	$20.34	$21.22	$20.58	$20.79	$19.77	$19.82	$20.20	$19.4[illegible]	$15.81	$19.41
1992	$15.55	$14.97	$14.80	$14.66	$14.50	$15.33	$14.72	$14.93	$14.23	$14.28	$14.64	$13.96	$11.41	$1[illegible].56
1993	$18.44	$17.74	$17.56	$17.41	$17.25	$18.11	$17.48	$17.69	$16.83	$16.88	$17.25	$16.56	$13.48	$16.31
1994	$21.04	$20.22	$20.03	$19.88	$19.71	$20.60	$19.95	$20.17	$19.16	$19.21	$19.59	$18.87	$15.34	$18.78
1995	$23.69	$23.21	$23.02	$22.87	$22.69	$23.61	$22.94	$23.16	$22.23	$22.29	$22.68	$21.94	$19.37	$21.77
1996	$25.55	$24.89	$24.69	$24.53	$24.35	$25.29	$24.61	$24.83	$23.57	$23.63	$24.03	$23.27	$19.70	$23.43

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	ARABIAN LIGHT PRICE (CRUDE OIL)	U.S. REFINER'S ACQUISITION COST (CRUDE OIL)	WTI FIRST FORWARD MONTH FUTURE'S PRICE (CRUDE OIL)	EVERGLADES (DISTILLATE FUEL OIL)	LAUDERDALE (DISTILLATE FUEL OIL)	FT MYER (DISTILLATE FUEL OIL)	PUTNAM (DISTILLATE FUEL OIL)
JAN94	$20.73	$22.23	$23.73	$30.74	$30.96	$30.69	$31.19
FEB	$19.72	$21.22	$22.72	$27.61	$27.84	$27.57	$28.07
MAR	$18.96	$20.46	$21.96	$26.68	$26.90	$26.63	$27.14
APR94	$18.47	$19.97	$21.47	$24.86	$25.08	$24.81	$25.31
MAY 94	$17.98	$19.48	$20.98	$23.39	$23.61	$23.34	$23.85
JUN	$19.10	$20.60	$22.10	$25.41	$25.63	$25.36	$25.87
JUL	$20.50	$22.00	$23.50	$27.21	$27.44	$27.16	$27.67
AUG	$21.63	$23.13	$24.63	$29.32	$29.54	$29.27	$29.73
SEP94	$20.87	$22.37	$23.87	$28.88	$29.11	$28.83	$29.35
OCT94	$21.47	$22.97	$24.47	$30.76	$30.99	$30.71	$31.22
NOV	$22.61	$24.11	$25.61	$32.99	$33.21	$32.94	$33.45
DEC	$23.76	$25.26	$26.76	$36.54	$36.77	$36.49	$37.01
JAN95	$23.46	$24.77	$26.27	$34.29	$34.52	$34.24	$34.76
FEB	$22.42	$23.73	$25.23	$30.92	$31.15	$30.87	$31.39
MAR	$21.65	$22.96	$24.46	$29.97	$30.20	$29.92	$30.44
APR95	$21.15	$22.46	$23.96	$27.98	$28.21	$27.93	$28.45
MAY 95	$20.65	$21.96	$23.46	$26.38	$26.61	$26.33	$26.86
JUN	$21.81	$23.12	$24.62	$28.54	$28.77	$28.49	$29.01
JUL	$23.26	$24.57	$26.07	$30.42	$30.65	$30.37	$30.89
AUG	$24.44	$25.75	$27.25	$32.66	$32.90	$32.61	$33.14
SEP95	$23.67	$24.98	$26.48	$32.28	$32.52	$32.23	$32.76
OCT95	$24.30	$25.61	$27.11	$34.33	$34.57	$34.28	$34.82
NOV	$25.49	$26.80	$28.30	$36.71	$36.94	$36.66	$37.19
DEC	$26.69	$28.00	$29.50	$40.56	$40.79	$40.51	$41.04
JAN96	$26.06	$26.56	$28.83	$36.48	$36.72	$36.43	$36.96
FEB	$25.00	$25.50	$27.77	$32.94	$33.18	$32.89	$33.42
MAR	$24.21	$24.71	$26.98	$31.98	$32.22	$31.93	$32.47
APR96	$23.71	$24.21	$26.48	$29.88	$30.12	$29.83	$30.37
MAY96	$23.20	$23.70	$25.97	$28.20	$28.44	$28.15	$28.69
JUN	$24.41	$24.91	$27.18	$30.46	$30.70	$30.41	$30.96
JUL	$25.92	$26.42	$28.69	$32.40	$32.64	$32.35	$32.89
AUG	$27.15	$27.65	$29.92	$34.75	$34.99	$34.70	$35.25
SEP96	$26.36	$26.86	$29.15	$34.40	$34.65	$34.35	$34.90
OCT96	$27.02	$27.52	$29.79	$36.58	$36.83	$36.53	$37.08
NOV	$28.26	$28.76	$31.03	$39.07	$39.31	$39.01	$39.57
DEC	$29.51	$30.01	$32.28	$43.13	$43.38	$43.08	$43.63

DATE	MARTIN (0.7%)	CANAVERAL (1.0% SULFUR)	EVERGLADES (1.0% SULFUR)	FT MYERS (1.0% SULFUR)	MANATEE (1.0% SULFUR)	SANFORD (1.0% SULFUR)	TURKEY POINT (1.0% SULFUR)	RIVIERA (1.0% SULFUR)	RIVIERA (1.5% RESIDUAL)	CANAVERAL (1.5% RESIDUAL)	SANFORD (1.5% RESIDUAL)	FT MYERS (1.5% RESIDUAL)	EVERGLADES (3.0%)	MEMO: 1% SULFUR RESIDUAL FUEL OIL & USGC
JAN94	$22.36	$21.48	$21.30	$21.15	$20.98	$21.86	$21.22	$21.43	$20.35	$20.40	$20.78	$20.07	$16.29	$20.05
FEB	$20.54	$19.74	$19.56	$19.41	$19.24	$20.12	$19.48	$19.69	$18.71	$18.76	$19.13	$18.43	$14.98	$18.31
MAR	$19.00	$18.27	$18.08	$17.94	$17.77	$18.65	$18.01	$18.22	$17.31	$17.36	$17.74	$17.03	$13.88	$16.83
APR94	$18.54	$17.83	$17.64	$17.49	$17.33	$18.21	$17.57	$17.78	$16.90	$16.95	$17.33	$16.61	$13.55	$16.39
MAY94	$18.24	$17.55	$17.36	$17.21	$17.05	$17.93	$17.28	$17.50	$16.63	$16.68	$17.06	$16.35	$13.34	$16.11
JUN	$19.50	$18.75	$18.56	$18.41	$18.25	$19.13	$18.48	$18.70	$17.77	$17.82	$18.20	$17.48	$14.24	$17.31
JUL	$21.54	$20.69	$20.51	$20.36	$20.19	$21.08	$20.43	$20.64	$19.61	$19.66	$20.04	$19.32	$15.69	$19.26
AUG	$22.09	$21.22	$21.04	$20.89	$20.72	$21.61	$20.96	$21.17	$20.11	$20.16	$20.54	$19.82	$16.09	$19.79
SEP94	$20.93	$20.11	$19.93	$19.77	$19.60	$20.50	$19.85	$20.06	$19.06	$19.11	$19.49	$18.77	$15.26	$18.67
OCT94	$21.96	$21.10	$20.91	$20.76	$20.59	$21.48	$20.83	$21.05	$19.99	$20.04	$20.43	$19.70	$16.00	$19.66
NOV	$23.31	$22.39	$22.20	$22.05	$21.88	$22.77	$22.12	$22.34	$21.21	$21.26	$21.65	$20.92	$16.96	$20.95
DEC	$24.45	$23.48	$23.29	$23.14	$22.97	$23.86	$23.21	$23.43	$22.24	$22.29	$22.68	$21.95	$17.78	$22.04
JAN95	$24.97	$24.45	$24.26	$24.11	$23.94	$24.84	$24.18	$24.40	$23.40	$23.45	$23.84	$23.11	$20.24	$23.01
FEB	$23.17	$22.70	$22.51	$22.36	$22.19	$23.09	$22.43	$22.65	$21.74	$21.80	$22.18	$21.45	$18.97	$21.26
MAR	$21.49	$21.09	$20.90	$20.74	$20.57	$21.48	$20.82	$21.03	$20.22	$20.27	$20.66	$19.93	$17.80	$19.64
APR95	$21.02	$20.63	$20.44	$20.28	$20.11	$21.02	$20.35	$20.57	$19.79	$19.84	$20.23	$19.49	$17.47	$19.18
MAY95	$20.74	$20.35	$20.16	$20.00	$19.83	$20.74	$20.07	$20.29	$19.52	$19.57	$19.97	$19.23	$17.27	$18.90
JUN	$22.07	$21.64	$21.45	$21.30	$21.12	$22.03	$21.37	$21.59	$20.75	$20.80	$21.19	$20.45	$18.22	$20.19
JUL	$24.26	$23.76	$23.57	$23.42	$23.24	$24.15	$23.49	$23.71	$22.75	$22.80	$23.20	$22.46	$19.77	$22.31
AUG	$24.80	$24.30	$24.11	$23.96	$23.78	$24.70	$24.03	$24.25	$23.26	$23.32	$23.71	$22.97	$20.18	$22.85
SEP95	$23.57	$23.11	$22.92	$22.76	$22.58	$23.50	$22.83	$23.05	$22.13	$22.19	$22.58	$21.84	$19.31	$21.66
OCT95	$24.69	$24.20	$24.00	$23.85	$23.67	$24.59	$23.92	$24.14	$23.16	$23.22	$23.61	$22.87	$20.11	$22.74
NOV	$26.13	$25.59	$25.40	$25.24	$25.07	$25.99	$25.32	$25.54	$24.48	$24.54	$24.94	$24.19	$21.13	$24.14
DEC	$27.33	$26.77	$26.57	$26.41	$26.24	$27.16	$26.49	$26.71	$25.59	$25.65	$26.05	$25.30	$22.00	$25.31
JAN96	$27.80	$27.05	$26.85	$26.69	$26.52	$27.45	$26.77	$26.99	$25.61	$25.66	$26.06	$25.31	$21.26	$25.59
FEB	$24.90	$24.25	$24.06	$23.90	$23.72	$24.65	$23.97	$24.20	$22.97	$23.02	$23.43	$22.67	$19.22	$22.80
MAR	$23.14	$22.56	$22.36	$22.21	$22.03	$22.96	$22.28	$22.50	$21.37	$21.43	$21.83	$21.07	$17.99	$21.10
APR96	$22.66	$22.10	$21.90	$21.74	$21.56	$22.50	$21.81	$22.04	$20.93	$20.99	$21.39	$20.63	$17.65	$20.64
MAY96	$22.38	$21.83	$21.63	$21.47	$21.29	$22.23	$21.55	$21.77	$20.68	$20.74	$21.14	$20.38	$17.46	$20.37
JUN	$23.78	$23.18	$22.98	$22.82	$22.64	$23.59	$22.90	$23.12	$21.96	$22.01	$22.42	$21.65	$18.45	$21.72
JUL	$26.09	$25.41	$25.21	$25.05	$24.87	$25.81	$25.12	$25.35	$24.06	$24.11	$24.52	$23.75	$20.08	$23.94
AUG	$26.63	$25.94	$25.74	$25.58	$25.40	$26.35	$25.66	$25.88	$24.56	$24.62	$25.03	$24.26	$20.47	$24.48
SEP96	$25.33	$24.69	$24.49	$24.33	$24.15	$25.10	$24.41	$24.64	$23.39	$23.44	$23.85	$23.08	$19.57	$23.23
OCT96	$26.53	$25.84	$25.65	$25.48	$25.30	$26.26	$25.56	$25.79	$24.67	$24.53	$24.94	$24.17	$20.41	$24.38
NOV	$28.04	$27.30	$27.10	$26.94	$26.76	$27.71	$27.02	$27.25	$25.85	$25.90	$26.31	$25.54	$21.48	$25.84
DEC	$29.29	$28.52	$28.32	$28.15	$27.97	$28.93	$28.23	$28.46	$26.99	$27.05	$27.46	$26.69	$22.37	$27.05

JANUARY 1992 TO DECEMBER 1996 FPL/ORI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 7/91 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D N O M I N A L D O L L A R F U E L P R I C E S I N D O L L A R S P E R M M B T U

JANUARY 10, 1992/FEBRUARY 4, 1992

	*****CRUDE OIL*****		*******DISTILLATE FUEL OIL**************			
DATE	ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN 92	$2.59	$2.84	$3.84	$3.88	$3.84	$3.92
FEB	$2.64	$2.89	$3.68	$3.72	$3.68	$3.76
MAR	$2.60	$2.86	$3.64	$3.68	$3.64	$3.72
APR92	$2.56	$2.82	$3.43	$3.47	$3.42	$3.51
MAY92	$2.52	$2.78	$3.27	$3.30	$3.26	$3.34
JUN	$2.70	$2.96	$3.58	$3.61	$3.57	$3.65
JULY	$2.89	$3.14	$3.81	$3.84	$3.80	$3.88
AUG	$3.07	$3.32	$4.13	$4.16	$4.12	$4.20
SEP192	$2.99	$3.24	$4.10	$4.14	$4.09	$4.18
OCT92	$3.17	$3.43	$4.50	$4.54	$4.49	$4.57
NOV	$3.35	$3.61	$4.84	$4.88	$4.84	$4.92
DEC	$3.54	$3.80	$5.39	$5.42	$5.38	$5.46
JAN93	$3.19	$3.45	$4.75	$4.79	$4.74	$4.83
FEB	$3.02	$3.28	$4.25	$4.29	$4.24	$4.33
MAR	$2.89	$3.15	$4.09	$4.13	$4.09	$4.17
APR93	$2.81	$3.07	$3.81	$3.84	$3.80	$3.88
MAY 93	$2.75	$2.99	$3.57	$3.61	$3.57	$3.65
JUN	$2.91	$3.17	$3.90	$3.94	$3.89	$3.98
JUL	$3.15	$3.40	$4.20	$4.23	$4.19	$4.27
AUG	$3.33	$3.59	$4.54	$4.58	$4.53	$4.61
SEP93	$3.21	$3.46	$4.46	$4.50	$4.45	$4.53
OCT93	$3.30	$3.56	$4.75	$4.79	$4.75	$4.83
NOV	$3.49	$3.75	$5.12	$5.15	$5.11	$5.19
DEC	$3.68	$3.94	$5.68	$5.72	$5.67	$5.76
1992	$2.88	$3.14	$4.02	$4.05	$4.01	$4.09
1993	$3.14	$3.40	$4.43	$4.46	$4.42	$4.50
1994	$3.51	$3.77	$4.92	$4.96	$4.91	$5.00
1995	$4.01	$4.21	$5.50	$5.54	$5.49	$5.59
1996	$4.33	$4.53	$5.86	$5.91	$5.86	$5.95

****************************D E L I V E R E D R E S I D U A L F U E L O I L ****************************

	0.7%	****************1.0% SULFUR RESIDUAL FUEL OIL******************							************1.5% RESIDUAL************				***3.0%***	MEMO: 1% SULFUR RESIDUAL FUEL OIL
DATE	MARTIN	CANAVERAL	EVERGLADES	FT MYERS	MANATEE	SANFORD	TURKEY POINT	RIVIERA	RIVIERA	CANAVERAL	SANFORD	FT MYERS	EVERGLADES	@ USGC
JAN 92	$2.02	$1.95	$1.92	$1.90	$1.88	$2.01	$1.91	$1.94	$1.86	$1.87	$1.92	$1.82	$1.50	$1.73
FEB	$2.12	$2.05	$2.02	$2.00	$1.97	$2.10	$2.01	$2.04	$1.95	$1.96	$2.01	$1.91	$1.57	$1.82
MAR	$2.19	$2.11	$2.09	$2.07	$2.04	$2.17	$2.08	$2.11	$2.01	$2.02	$2.08	$1.97	$1.62	$1.89
APR92	$2.16	$2.09	$2.06	$2.04	$2.01	$2.14	$2.05	$2.08	$1.99	$1.99	$2.05	$1.94	$1.60	$1.86
MAY92	$2.15	$2.08	$2.05	$2.03	$2.01	$2.14	$2.04	$2.07	$1.98	$1.99	$2.04	$1.94	$1.59	$1.86
JUN	$2.32	$2.24	$2.21	$2.19	$2.16	$2.29	$2.20	$2.23	$2.13	$2.14	$2.19	$2.09	$1.71	$2.02
JULY	$2.55	$2.46	$2.43	$2.41	$2.39	$2.52	$2.42	$2.45	$2.34	$2.35	$2.41	$2.30	$1.88	$2.24
AUG	$2.63	$2.53	$2.50	$2.48	$2.46	$2.59	$2.49	$2.52	$2.41	$2.42	$2.47	$2.37	$1.93	$2.31
SEP192	$2.51	$2.42	$2.39	$2.37	$2.34	$2.47	$2.38	$2.41	$2.30	$2.31	$2.37	$2.26	$1.85	$2.19
OCT92	$2.71	$2.61	$2.59	$2.56	$2.54	$2.67	$2.57	$2.61	$2.49	$2.49	$2.55	$2.44	$1.99	$2.39
NOV	$2.89	$2.78	$2.76	$2.75	$2.71	$2.84	$2.74	$2.78	$2.65	$2.66	$2.71	$2.61	$2.12	$2.56
DEC	$3.04	$2.93	$2.90	$2.88	$2.85	$2.99	$2.87	$2.92	$2.79	$2.79	$2.85	$2.74	$2.23	$2.71
JAN93	$2.98	$2.87	$2.85	$2.82	$2.80	$2.93	$2.83	$2.87	$2.73	$2.74	$2.80	$2.69	$2.19	$2.65
FEB	$2.83	$2.73	$2.70	$2.68	$2.65	$2.79	$2.69	$2.72	$2.59	$2.60	$2.66	$2.55	$2.08	$2.51
MAR	$2.61	$2.52	$2.49	$2.46	$2.44	$2.57	$2.48	$2.51	$2.39	$2.40	$2.46	$2.35	$1.92	$2.29
APR93	$2.54	$2.45	$2.42	$2.40	$2.37	$2.51	$2.41	$2.44	$2.33	$2.34	$2.39	$2.29	$1.87	$2.23
MAY 93	$2.49	$2.41	$2.38	$2.35	$2.33	$2.46	$2.37	$2.40	$2.29	$2.29	$2.35	$2.24	$1.84	$2.18
JUN	$2.68	$2.58	$2.55	$2.53	$2.50	$2.64	$2.54	$2.57	$2.45	$2.46	$2.52	$2.41	$1.97	$2.36
JUL	$2.97	$2.86	$2.84	$2.81	$2.79	$2.92	$2.82	$2.86	$2.72	$2.73	$2.79	$2.68	$2.18	$2.64
AUG	$3.06	$2.95	$2.92	$2.90	$2.87	$3.01	$2.91	$2.94	$2.80	$2.61	$2.87	$2.76	$2.24	$2.72
SEP93	$2.89	$2.78	$2.76	$2.73	$2.71	$2.84	$2.74	$2.78	$2.65	$2.65	$2.71	$2.60	$2.12	$2.56
OCT93	$3.04	$2.93	$2.90	$2.87	$2.85	$2.99	$2.89	$2.92	$2.78	$2.79	$2.85	$2.74	$2.23	$2.70
NOV	$3.24	$3.12	$3.09	$3.06	$3.04	$3.17	$3.07	$3.11	$2.96	$2.97	$3.03	$2.92	$2.37	$2.89
DEC	$3.40	$3.28	$3.25	$3.22	$3.20	$3.34	$3.24	$3.27	$3.11	$3.12	$3.18	$3.07	$2.49	$3.05
1992	$2.44	$2.35	$2.33	$2.30	$2.28	$2.41	$2.32	$2.35	$2.24	$2.25	$2.31	$2.20	$1.80	$2.13
1993	$2.90	$2.79	$2.76	$2.74	$2.71	$2.85	$2.75	$2.78	$2.65	$2.66	$2.72	$2.61	$2.13	$2.56
1994	$3.30	$3.17	$3.14	$3.12	$3.09	$3.23	$3.13	$3.17	$3.01	$3.02	$3.08	$2.96	$2.41	$2.95
1995	$3.72	$3.64	$3.61	$3.59	$3.56	$3.71	$3.60	$3.64	$3.49	$3.50	$3.56	$3.44	$3.04	$3.42
1996	$4.01	$3.91	$3.88	$3.85	$3.82	$3.97	$3.86	$3.90	$3.70	$3.71	$3.77	$3.65	$3.09	$3.68

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D   N O M I N A L   D O L L A R   F U E L   P R I C E S   I N   D O L L A R S   P E R   M M B T U

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	*******CRUDE OIL******* ARABIAN LIGHT PRICE	U.S. REFINER ACQUISITION COST	*******DISTILLATE FUEL OIL************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN94	$3.56	$3.81	$5.27	$5.31	$5.26	$5.35
FEB	$3.38	$3.64	$4.74	$4.77	$4.73	$4.81
MAR	$3.25	$3.51	$4.58	$4.61	$4.57	$4.65
APR94	$3.17	$3.43	$4.26	$4.30	$4.25	$4.34
MAY 94	$3.08	$3.34	$4.01	$4.05	$4.00	$4.09
JUN	$3.28	$3.53	$4.36	$4.40	$4.35	$4.44
JUL	$3.52	$3.77	$4.67	$4.71	$4.66	$4.75
AUG	$3.71	$3.97	$5.03	$5.07	$5.02	$5.11
SEP94	$3.58	$3.84	$4.95	$4.99	$4.95	$5.03
OCT94	$3.68	$3.94	$5.28	$5.31	$5.27	$5.36
NOV	$3.88	$4.14	$5.66	$5.70	$5.65	$5.74
DEC	$4.08	$4.33	$6.27	$6.31	$6.26	$6.35
JAN95	$4.06	$4.25	$5.88	$5.92	$5.87	$5.96
FEB	$3.86	$4.07	$5.30	$5.34	$5.29	$5.38
MAR	$3.73	$3.94	$5.14	$5.18	$5.13	$5.22
APR95	$3.65	$3.85	$4.80	$4.84	$4.79	$4.88
MAY 95	$3.56	$3.77	$4.53	$4.57	$4.52	$4.61
JUN	$3.76	$3.97	$4.89	$4.93	$4.89	$4.98
JUL	$4.01	$4.22	$5.22	$5.26	$5.21	$5.30
AUG	$4.21	$4.42	$5.60	$5.64	$5.59	$5.68
SEP95	$4.08	$4.29	$5.54	$5.58	$5.53	$5.62
OCT95	$4.19	$4.39	$5.89	$5.93	$5.88	$5.97
NOV	$4.39	$4.60	$6.30	$6.34	$6.29	$6.38
DEC	$4.60	$4.80	$6.96	$7.00	$6.95	$7.04
JAN96	$4.36	$4.56	$6.26	$6.30	$6.25	$6.34
FEB	$4.18	$4.37	$5.65	$5.69	$5.64	$5.73
MAR	$4.04	$4.24	$5.49	$5.53	$5.48	$5.57
APR96	$3.96	$4.15	$5.13	$5.17	$5.12	$5.21
MAY96	$3.87	$4.07	$4.84	$4.88	$4.83	$4.92
JUN	$4.08	$4.27	$5.23	$5.27	$5.22	$5.31
JUL	$4.33	$4.53	$5.56	$5.60	$5.55	$5.64
AUG	$4.55	$4.74	$5.96	$6.00	$5.95	$6.05
SEP96	$4.41	$4.61	$5.90	$5.94	$5.89	$5.99
OCT96	$4.52	$4.72	$6.28	$6.32	$6.27	$6.36
NOV	$4.74	$4.93	$6.70	$6.74	$6.69	$6.79
DEC	$4.95	$5.15	$7.40	$7.44	$7.39	$7.48

****************************D E L I V E R E D   R E S I D U A L   F U E L   O I L ******************************

DATE	*0.7%* MARTIN	****1.0% SULFUR RESIDUAL FUEL OIL**** CANAVERAL	EVERGLADES	FT MYERS	MANATEE	SANFORD	TURKEY POINT	RIVIERA	****1.5% RESIDUAL**** RIVIERA	CANAVERAL	SANFORD	FT MYERS	***3.0%*** EVERGLADES	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
JAN94	$3.51	$3.37	$3.34	$3.32	$3.29	$3.43	$3.33	$3.36	$3.19	$3.20	$3.26	$3.15	$2.56	$3.15
FEB	$3.22	$3.10	$3.07	$3.05	$3.02	$3.16	$3.06	$3.09	$2.94	$2.94	$3.00	$2.89	$2.35	$2.88
MAR	$2.98	$2.87	$2.84	$2.82	$2.79	$2.93	$2.83	$2.86	$2.72	$2.73	$2.79	$2.67	$2.18	$2.65
APR94	$2.91	$2.80	$2.77	$2.75	$2.72	$2.86	$2.76	$2.79	$2.65	$2.66	$2.72	$2.61	$2.13	$2.58
MAY 94	$2.86	$2.75	$2.73	$2.70	$2.68	$2.81	$2.71	$2.75	$2.61	$2.62	$2.68	$2.57	$2.09	$2.53
JUN	$3.06	$2.94	$2.91	$2.89	$2.86	$3.00	$2.90	$2.94	$2.79	$2.80	$2.86	$2.74	$2.23	$2.72
JUL	$3.38	$3.25	$3.22	$3.20	$3.17	$3.31	$3.21	$3.24	$3.08	$3.09	$3.15	$3.03	$2.46	$3.03
AUG	$3.47	$3.33	$3.30	$3.28	$3.25	$3.39	$3.29	$3.32	$3.16	$3.17	$3.23	$3.11	$2.53	$3.11
SEP94	$3.29	$3.16	$3.13	$3.10	$3.08	$3.22	$3.12	$3.15	$2.99	$3.00	$3.06	$2.95	$2.40	$2.94
OCT94	$3.45	$3.31	$3.28	$3.26	$3.23	$3.37	$3.27	$3.30	$3.14	$3.15	$3.21	$3.09	$2.51	$3.09
NOV	$3.66	$3.51	$3.49	$3.46	$3.43	$3.58	$3.47	$3.51	$3.33	$3.34	$3.40	$3.28	$2.66	$3.29
DEC	$3.84	$3.69	$3.66	$3.63	$3.61	$3.75	$3.64	$3.68	$3.49	$3.50	$3.56	$3.45	$2.79	$3.46
JAN95	$3.92	$3.84	$3.81	$3.78	$3.76	$3.90	$3.80	$3.83	$3.67	$3.68	$3.74	$3.63	$3.18	$3.62
FEB	$3.64	$3.56	$3.53	$3.51	$3.48	$3.62	$3.52	$3.56	$3.41	$3.42	$3.48	$3.37	$2.98	$3.34
MAR	$3.37	$3.31	$3.28	$3.26	$3.23	$3.37	$3.27	$3.30	$3.17	$3.18	$3.24	$3.13	$2.79	$3.09
APR95	$3.30	$3.24	$3.21	$3.18	$3.16	$3.30	$3.20	$3.23	$3.11	$3.11	$3.18	$3.06	$2.74	$3.02
MAY 95	$3.26	$3.19	$3.16	$3.14	$3.11	$3.26	$3.15	$3.19	$3.06	$3.07	$3.13	$3.02	$2.71	$2.97
JUN	$3.46	$3.40	$3.37	$3.34	$3.32	$3.46	$3.35	$3.39	$3.26	$3.27	$3.33	$3.21	$2.86	$3.18
JUL	$3.81	$3.73	$3.70	$3.68	$3.65	$3.79	$3.69	$3.72	$3.57	$3.58	$3.64	$3.53	$3.10	$3.51
AUG	$3.89	$3.82	$3.79	$3.76	$3.73	$3.88	$3.77	$3.81	$3.65	$3.66	$3.72	$3.61	$3.17	$3.59
SEP95	$3.70	$3.63	$3.60	[illegible]	$3.55	$3.69	$3.58	$3.62	$3.47	$3.48	$3.55	$3.43	$3.03	$3.41
OCT95	$3.88	$3.80	$3.77	$3.74	$3.72	$3.86	$3.76	$3.79	$3.64	$3.64	$3.71	$3.59	$3.16	$3.58
NOV	$4.10	$4.02	$3.99	$3.96	$3.94	$4.08	$3.97	$4.01	$3.84	$3.85	$3.91	$3.80	$3.32	$3.80
DEC	$4.29	$4.20	$4.17	$4.15	$4.12	$4.26	$4.16	$4.19	$4.02	$4.03	$4.09	$3.97	$3.45	$3.98
JAN96	$4.36	$4.25	$4.22	$4.19	$4.16	$4.31	$4.20	$4.24	$4.02	$4.03	$4.09	$3.97	$3.34	$4.02
FEB	$3.91	$3.81	$3.78	$3.75	$3.72	$3.87	$3.76	$3.80	$3.61	$3.61	$3.68	$3.56	$3.02	$3.58
MAR	$3.63	$3.54	$3.51	$3.49	$3.46	$3.60	$3.50	$3.53	$3.35	$3.36	$3.43	$3.31	$2.82	$3.32
APR96	$3.56	$3.47	$3.44	$3.41	$3.38	$3.53	$3.42	$3.46	$3.29	$3.29	$3.36	$3.24	$2.77	$3.24
MAY96	$3.51	$3.43	$3.40	$3.37	$3.34	$3.49	$3.38	$3.42	$3.25	$3.26	$3.32	$3.20	$2.74	$3.20
JUN	$3.73	$3.64	$3.61	$3.58	$3.55	$3.70	$3.59	$3.63	$3.45	$3.46	$3.52	$3.40	$2.90	$3.41
JUL	$4.10	$3.99	$3.96	$3.93	$3.90	$4.05	$3.94	$3.98	$3.78	$3.79	$3.85	$3.73	$3.15	$3.76
AUG	$4.18	$4.07	$4.04	$4.02	$3.99	$4.14	$4.03	$4.06	$3.86	$3.86	$3.93	$3.81	$3.21	$3.85
SEP96	$3.98	$3.88	$3.85	$3.82	$3.79	$3.94	$3.83	$3.87	$3.67	$3.68	$3.74	$3.62	$3.07	$3.65
OCT96	$4.16	$4.06	$4.03	$4.00	$3.97	$4.12	$4.01	$4.05	$3.84	$3.85	$3.92	$3.79	$3.20	$3.83
NOV	$4.40	$4.29	$4.25	$4.23	$4.20	$4.35	$4.24	$4.28	$4.06	$4.07	$4.13	$4.01	$3.37	$4.06
DEC	$4.60	$4.48	$4.45	$4.42	$4.39	$4.54	$4.43	$4.47	$4.24	$4.25	$4.31	$4.19	$3.51	$4.25

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D 1 9 9 1 D O L L A R F U E L P R I C E S I N D O L L A R S P E R B A R R E L

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	*******CRUDE OIL******* ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	*******DISTILLATE FUEL OIL************* EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN 92	$15.00	$16.49	$22.29	$22.50	$22.25	$22.72
FEB	$15.25	$16.74	$21.32	$21.53	$21.28	$21.75
MAR	$15.00	$16.48	$21.04	$21.25	$21.00	$21.47
APR92	$14.75	$16.23	$19.78	$19.99	$19.73	$20.21
MAY92	$14.50	$15.98	$18.79	$19.00	$18.74	$19.22
JUN	$15.50	$16.97	$20.51	$20.72	$20.46	$20.94
JULY	$16.50	$17.97	$21.78	$21.99	$21.74	$22.21
AUG	$17.50	$18.97	$23.56	$23.77	$23.52	$23.99
SEP192	$17.00	$18.46	$23.37	$23.58	$23.33	$23.80
OC192	$18.00	$19.46	$25.57	$25.78	$25.53	$26.00
NOV	$19.00	$20.46	$27.47	$27.68	$27.42	$27.90
DEC	$20.00	$21.45	$30.48	$30.69	$30.44	$30.91
JAN93	$18.00	$19.45	$26.83	$27.04	$26.79	$27.26
FEB	$17.00	$18.45	$23.97	$24.18	$23.92	$24.39
MAR	$16.25	$17.69	$23.03	$23.24	$22.98	$23.46
APR93	$15.75	$17.19	$21.36	$21.57	$21.32	$21.79
MAY 93	$15.25	$16.69	$20.02	$20.23	$19.97	$20.45
JUN	$16.25	$17.68	$21.79	$22.00	$21.74	$22.22
JUL	$17.50	$18.93	$23.40	$23.61	$23.35	$23.83
AUG	$18.50	$19.93	$25.23	$25.44	$25.19	$25.66
SEP93	$17.75	$19.17	$24.73	$24.94	$24.68	$25.16
OC193	$18.25	$19.67	$26.31	$26.52	$26.27	$26.74
NOV	$19.25	$20.67	$28.24	$28.45	$28.20	$28.67
DEC	$20.25	$21.66	$31.30	$31.51	$31.25	$31.73
1992	$16.50	$17.97	$2[illegible].00	$23.21	$22.95	$23.43
1993	$17.50	$18.93	$24.68	$24.89	$24.64	$25.11
1994	$19.00	$20.39	$26.69	$26.90	$26.65	$27.12
1995	$20.75	$22.10	$28.97	$29.18	$28.93	$29.40
1996	$21.66	$22.97	$29.87	$30.08	$29.83	$30.30

	**********************************D E L I V E R E D R E S I D U A L F U E L O I L *********************************													MEMO:
	0.7%	****************1.0% SULFUR RESIDUAL FUEL OIL**********************							************1.5% RESIDUAL************				***3.0%***	1% SULFUR RESIDUAL FUEL OIL
DATE	MARTIN	CANAVERAL	EVERGLADES	FT MYERS	MANATEE	SANFORD	TURKEY POINT	RIVIERA	RIVIERA	CANAVERAL	SANFORD	FT MYERS	EVERGLADES	@ USGC
JAN 92	$12.80	$12.35	$12.17	$12.03	$11.88	$12.70	$12.10	$12.30	$11.74	$11.79	$12.14	$11.47	$9.44	$10.94
FEB	$13.40	$12.92	$12.75	$12.61	$12.45	$13.27	$12.67	$12.87	$12.28	$12.33	$12.68	$12.02	$9.87	$11.51
MAR	$13.83	$13.33	$13.15	$13.01	$12.86	$13.68	$13.08	$13.28	$12.67	$12.71	$13.07	$12.40	$10.17	$11.92
APR92	$13.62	$13.12	$12.95	$12.81	$12.65	$13.48	$12.88	$13.07	$12.47	$12.52	$12.80	$12.21	$10.02	$11.71
MAY92	$13.54	$13.05	$12.88	$12.74	$12.58	$13.40	$12.80	$13.00	$12.40	$12.45	$12.81	$12.14	$9.97	$11.64
JUN	$14.55	$14.01	$13.84	$13.70	$13.54	$14.37	$13.77	$13.96	$13.32	$13.37	$13.72	$13.05	$10.69	$12.60
JULY	$15.97	$15.37	$15.20	$15.06	$14.90	$15.72	$15.13	$15.32	$14.61	$14.66	$15.01	$14.34	$11.71	$13.96
AUG	$16.40	$15.78	$15.61	$15.47	$15.32	$16.14	$15.54	$15.74	$15.00	$15.05	$15.40	$14.74	$12.02	$14.37
SEP192	$15.61	$15.03	$14.86	$14.72	$14.56	$15.39	$14.79	$14.98	$14.29	$14.33	$14.69	$14.02	$11.45	$13.62
OC192	$16.85	$16.21	$16.04	$15.90	$15.75	$16.57	$15.97	$16.17	$15.41	$15.46	$15.81	$15.14	$12.34	$14.80
NOV	$17.92	$17.24	$17.07	$16.93	$16.77	$17.59	$16.99	$17.19	$16.38	$16.43	$16.78	$16.12	$13.11	$15.83
DEC	$18.82	$18.09	$17.92	$17.78	$17.62	$18.45	$17.85	$18.04	$17.19	$17.24	$17.59	$16.93	$13.75	$16.68
JAN93	$18.42	$17.71	$17.54	$17.40	$17.24	$18.06	$17.46	$17.66	$16.81	$16.85	$17.21	$16.54	$13.46	$16.30
FEB	$17.45	$16.79	$16.62	$16.48	$16.32	$17.14	$16.54	$16.74	$15.93	$15.98	$16.34	$15.67	$12.77	$15.38
MAR	$16.05	$15.45	$15.28	$15.14	$14.98	$15.80	$15.20	$15.40	$14.66	$14.71	$15.06	$14.40	$11.77	$14.04
APR93	$15.59	$15.01	$14.84	$14.70	$14.54	$15.36	$14.76	$14.96	$14.25	$14.30	$14.65	$13.99	$11.44	$13.60
MAY 93	$15.28	$14.71	$14.54	$14.40	$14.24	$15.06	$14.47	$14.66	$13.96	$14.01	$14.37	$13.70	$11.21	$13.30
JUN	$16.37	$15.75	$15.58	$15.44	$15.28	$16.10	$15.51	$15.70	$14.95	$15.00	$15.35	$14.69	$11.99	$14.34
JUL	$18.13	$17.43	$17.26	$17.12	$16.97	$17.79	$17.19	$17.39	$16.54	$16.59	$16.95	$16.28	$13.26	$16.02
AUG	$18.61	$17.89	$17.72	$17.58	$17.42	$18.25	$17.65	$17.84	$16.98	$17.03	$17.38	$16.71	$13.60	$16.46
SEP93	$17.53	$16.87	$16.70	$16.56	$16.40	$17.22	$16.62	$16.82	$16.01	$16.06	$16.41	$15.74	$12.83	$15.[illegible]
OC193	$18.39	$17.69	$17.52	$17.38	$17.22	$18.04	$17.44	$17.64	$16.79	$16.83	$17.19	$16.52	$13.45	$16.28
NOV	$19.54	$18.79	$18.61	$18.47	$18.32	$19.14	$18.54	$18.74	$17.83	$17.87	$18.23	$17.56	$14.27	$17.38
DEC	$20.51	$19.71	$19.54	$19.40	$19.24	$20.06	$19.46	$19.66	$18.70	$18.75	$19.10	$18.[illegible]	$14.96	$18.30
1992	$15.28	$14.71	$14.54	$14.40	$14.24	$15.06	$14.46	$14.66	$13.98	$14.03	$14.38	$13.72	$11.21	$13.30
1993	$17.66	$16.98	$16.81	$16.67	$16.52	$17.34	$16.74	$16.93	$16.12	$16.17	$16.52	$15.85	$12.92	$15.57
1994	$19.59	$18.83	$18.66	$18.52	$18.36	$19.18	$18.58	$18.78	$17.85	$17.89	$18.25	$17.58	$14.30	$17.42
1995	$21.42	$20.99	$20.82	$20.68	$20.53	$21.35	$20.75	$20.95	$20.11	$20.16	$20.51	$19.85	$17.54	$19.58
1996	$22.36	$21.79	$21.62	$21.48	$21.32	$22.14	$21.54	$21.74	$20.64	$20.69	$21.04	$20.38	$17.28	$20.38

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

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JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	*******CRUDE OIL******* ARABIAN LIGHT PRICE	U.S. REFINER'S ACQUISITION COST	*******DISTILLATE FUEL OIL************** EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM
JAN94	$19.50	$20.91	$28.97	$29.18	$28.92	$29.40
FEB	$18.50	$19.91	$25.97	$26.18	$25.93	$26.40
MAR	$17.75	$19.15	$25.04	$25.25	$24.99	$25.47
APR94	$17.25	$18.65	$23.28	$23.49	$23.23	$23.71
MAY 94	$16.75	$18.15	$21.86	$22.07	$21.81	$22.29
JUN	$17.75	$19.14	$23.68	$23.89	$23.64	$24.11
JUL	$19.00	$20.39	$25.30	$25.51	$25.26	$25.73
AUG	$20.00	$21.39	$27.19	$27.40	$27.14	$27.61
SEP94	$19.25	$20.63	$26.72	$26.93	$26.67	$27.15
OCT94	$19.75	$21.13	$28.38	$28.59	$28.34	$28.81
NOV	$20.75	$22.13	$30.36	$30.57	$30.31	$30.79
DEC	$21.75	$23.12	$33.54	$33.75	$33.49	$33.97
JAN95	$21.25	$22.62	$31.40	$31.61	$31.36	$31.83
FEB	$20.25	$21.62	$28.26	$28.47	$28.21	$28.68
MAR	$19.50	$20.86	$27.33	$27.54	$27.28	$27.75
APR95	$19.00	$20.36	$25.46	$25.67	$25.41	$25.88
MAY 95	$18.50	$19.86	$23.95	$24.16	$23.91	$24.38
JUN	$19.50	$20.85	$25.84	$26.05	$25.79	$26.27
JUL	$20.75	$22.10	$27.46	$27.67	$27.42	$27.89
AUG	$21.75	$23.10	$29.40	$29.61	$29.35	$29.83
SEP95	$21.00	$22.34	$28.98	$29.19	$28.93	$29.41
OCT95	$21.50	$22.84	$30.73	$30.94	$30.69	$31.16
NOV	$22.50	$23.83	$32.76	$32.97	$32.71	$33.19
DEC	$23.50	$24.83	$36.08	$36.29	$36.04	$36.51
JAN96	$22.16	$23.49	$32.38	$32.59	$32.33	$32.81
FEB	$21.16	$22.48	$29.17	$29.38	$29.12	$29.60
MAR	$20.41	$21.73	$28.25	$28.46	$28.20	$28.68
APR96	$19.91	$21.23	$26.33	$26.54	$26.28	$26.76
MAY96	$19.41	$20.72	$24.79	$25.00	$24.74	$25.22
JUN	$20.41	$21.72	$26.69	$26.90	$26.65	$27.12
JUL	$21.66	$22.96	$28.30	$28.51	$28.26	$28.73
AUG	$22.66	$23.96	$30.26	$30.47	$30.21	$30.68
SEP96	$21.91	$23.21	$29.87	$30.08	$29.82	$30.30
OCT96	$22.41	$23.70	$31.66	$31.87	$31.62	$32.09
NOV	$23.41	$24.70	$33.70	$33.91	$33.66	$34.13
DEC	$24.41	$25.69	$37.09	$37.30	$37.04	$37.52

********************************D E L I V E R E D R E S I D U A L F U E L O I L ********************************

DATE	*0.7%* MARTIN	****************1.0% SULFUR RESIDUAL FUEL OIL******************* CANAVERAL	EVERGLADES	FT MYERS	MANATEE	SANFORD	TURKEY POINT	RIVIERA	************1.5% RESIDUAL************* RIVIERA	CANAVERAL	SANFORD	FT MYERS	***3.0%*** EVERGLADES	MEMO: 1% SULFUR RESIDUAL FUEL OIL @ USGC
JAN94	$21.09	$20.27	$20.09	$19.95	$19.80	$20.62	$20.02	$20.22	$19.20	$19.25	$19.61	$18.94	$15.38	$18.86
FEB	$19.34	$18.59	$18.42	$18.28	$18.12	$18.96	$18.34	$18.54	$17.62	$17.67	$18.02	$17.35	$14.12	$17.18
MAR	$17.85	$17.17	$16.99	$16.85	$16.70	$17.52	$16.92	$17.12	$16.27	$16.32	$16.67	$16.01	$13.06	$15.76
APR94	$17.38	$16.72	$16.55	$16.41	$16.25	$17.07	$16.47	$16.67	$15.85	$15.89	$16.25	$15.58	$12.72	$15.31
MAY 94	$17.07	$16.42	$16.25	$16.11	$15.95	$16.77	$16.17	$16.37	$15.56	$15.61	$15.97	$15.30	$12.49	$15.01
JUN	$18.20	$17.50	$17.33	$17.19	$17.03	$17.85	$17.25	$17.45	$16.59	$16.63	$16.99	$16.32	$13.30	$16.09
JUL	$20.04	$19.26	$19.09	$18.95	$18.79	$19.61	$19.01	$19.21	$18.25	$18.30	$18.65	$17.99	$14.63	$17.85
AUG	$20.51	$19.70	$19.53	$19.39	$19.24	$20.06	$19.46	$19.66	$18.67	$18.72	$19.07	$18.41	$14.96	$18.29
SEP94	$19.38	$18.63	$18.46	$18.32	$18.16	$18.99	$18.39	$18.58	$17.66	$17.71	$18.06	$17.40	$14.15	$17.22
OCT94	$20.29	$19.50	$19.32	$19.19	$19.03	$19.85	$19.25	$19.45	$18.48	$18.52	$18.88	$18.21	$14.80	$18.09
NOV	$21.48	$20.63	$20.46	$20.32	$20.17	$20.99	$20.39	$20.59	$19.55	$19.60	$19.95	$19.29	$15.66	$19.22
DEC	$22.47	$21.58	$21.41	$21.27	$21.11	$21.94	$21.34	$21.53	$20.45	$20.50	$20.85	$20.19	$16.37	$20.17
JAN95	$22.90	$22.42	$22.25	$22.11	$21.95	$22.77	$22.17	$22.37	$21.46	$21.50	$21.86	$21.19	$18.58	$21.01
FEB	$21.20	$20.77	$20.60	$20.46	$20.30	$21.12	$20.53	$20.72	$19.90	$19.95	$20.30	$19.64	$17.37	$19.36
MAR	$19.63	$19.26	$19.08	$18.95	$18.79	$19.61	$19.01	$19.21	$18.47	$18.52	$18.87	$18.21	$16.27	$17.85
APR95	$19.15	$18.79	$18.62	$18.48	$18.33	$19.15	$18.55	$18.75	$18.03	$18.08	$18.43	$17.77	$15.93	$17.38
MAY 95	$18.85	$18.50	$18.32	$18.18	$18.03	$18.85	$18.25	$18.45	$17.75	$17.80	$18.15	$17.49	$15.71	$17.09
JUN	$20.01	$19.62	$19.45	$19.31	$19.15	$19.97	$19.38	$19.57	$18.81	$18.86	$19.22	$18.55	$16.54	$18.21
JUL	$21.92	$21.48	$21.30	$21.16	$21.01	$21.83	$21.23	$21.43	$20.57	$20.61	$20.97	$20.30	$17.89	$20.07
AUG	$22.35	$21.90	$21.73	$21.59	$21.44	$22.26	$21.66	$21.86	$20.97	$21.02	$21.37	$20.71	$18.20	$20.49
SEP95	$21.19	$20.78	$20.60	$20.47	$20.31	$21.13	$20.53	$20.73	$19.91	$19.95	$20.31	$19.64	$17.38	$19.37
OCT95	$22.13	$21.69	$21.52	$21.38	$21.22	$22.04	$21.45	$21.64	$20.77	$20.82	$21.17	$20.51	$18.05	$20.28
NOV	$23.35	$22.88	$22.70	$22.56	$22.41	$23.23	$22.63	$22.83	$21.89	$21.94	$22.29	$21.63	$18.91	$21.47
DEC	$24.35	$23.85	$23.68	$23.54	$23.39	$24.21	$23.61	$23.80	$22.81	$22.86	$23.21	$22.55	$19.62	$22.44
JAN96	$24.71	$24.04	$23.86	$23.73	$23.57	$24.39	$23.79	$23.99	$22.76	$22.81	$23.16	$22.50	$18.92	$22.63
FEB	$22.08	$21.51	$21.34	$21.20	$21.04	$21.86	$21.26	$21.46	$20.38	$20.43	$20.78	$20.11	$17.07	$20.10
MAR	$20.47	$19.96	$19.79	$19.65	$19.49	$20.32	$19.72	$19.91	$18.92	$18.97	$19.32	$18.65	$15.94	$18.55
APR96	$20.00	$19.50	$19.33	$19.19	$19.03	$19.86	$19.26	$19.45	$18.48	$18.53	$18.89	$18.22	$15.61	$18.09
MAY96	$19.70	$19.22	$19.04	$18.90	$18.75	$19.57	$18.97	$19.17	$18.21	$18.26	$18.62	$17.95	$15.40	$17.81
JUN	$20.87	$20.34	$20.17	$20.03	$19.88	$20.70	$20.10	$20.30	$19.28	$19.33	$19.68	$19.01	$16.22	$18.93
JUL	$22.81	$22.22	$22.05	$21.91	$21.75	$22.57	$21.97	$22.17	$21.05	$21.10	$21.45	$20.79	$17.59	$20.81
AUG	$23.22	$22.62	$22.45	$22.31	$22.15	$22.97	$22.38	$22.57	$21.43	$21.48	$21.83	$21.16	$17.89	$21.21
SEP96	$22.03	$21.48	$21.31	$21.17	$21.01	$21.83	$21.23	$21.43	$20.35	$20.40	$20.75	$20.09	$17.05	$20.07
OCT96	$23.00	$22.41	$22.24	$22.10	$21.94	$22.76	$22.16	$22.36	$21.23	$21.28	$21.63	$20.96	$17.73	$21.0[illegible]
NOV	$24.23	$23.60	$23.43	$23.29	$23.13	$23.95	$23.35	$23.55	$22.35	$22.40	$22.75	$22.09	$18.60	$22.10
DEC	$25.23	$24.57	$24.40	$24.26	$24.10	$24.92	$24.32	$24.52	$23.27	$23.31	$23.67	$23.00	$19.31	$23.16

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

DELIVERED 1991 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS
PER MMBTU & NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY
JANUARY 10, 1992/FEBRUARY 4, 1992

	PHASE I & II VOLUMES									PHASE III		
	NON-FIRM SERVICE		FIRM SERVICE		SYSTEM WEIGHTED AVERAGE		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY			FIRM SERVICE		FIRM NATURAL GAS AVAILABILITY
DATE	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL	MMCF/DAY
JAN 92	$1.68	$1.69	$1.81	$1.82	$1.79	$1.80	52	255	307			
FEB	$1.68	$1.70	$1.89	$1.90	$1.83	$1.84	102	255	357			
MAR	$1.63	$1.65	$1.94	$1.96	$1.83	$1.85	147	255	402			
APR92	$1.68	$1.71	$1.92	$1.94	$1.83	$1.86	157	280	437			
MAY92	$1.72	$1.75	$1.91	$1.94	$1.91	$1.94	6	430	436			
JUN	$1.72	$1.75	$2.05	$2.08	$2.05	$2.08	6	430	436			
JULY	$1.77	$1.81	$2.24	$2.28	$2.24	$2.28	27	430	457			
AUG	$1.82	$1.86	$2.30	$2.35	$2.30	$2.35	0	430	430			
SEP192	$1.87	$1.91	$2.21	$2.26	$2.21	$2.26	22	430	452			
OCT92	$2.06	$2.12	$2.40	$2.46	$2.27	$2.33	179	280	459			
NOV	$2.26	$2.33	$2.55	$2.63	$2.41	$2.48	233	255	488			
DEC	$2.35	$2.43	$2.65	$2.73	$2.52	$2.60	190	255	445			
JAN93	$2.35	$2.43	$2.61	$2.70	$2.61	$2.70	0	255	255			
FEB	$2.11	$2.19	$2.48	$2.57	$2.42	$2.51	48	255	303			
MAR	$1.84	$1.91	$2.26	$2.35	$2.14	$2.23	97	255	352			
APR93	$1.69	$1.76	$2.17	$2.26	$2.03	$2.12	111	280	391			
MAY	$1.66	$1.73	$2.12	$2.21	$2.12	$2.21	0	430	430			
JUN	$1.82	$1.91	$2.29	$2.40	$2.29	$2.40	0	430	430			
JUL	$1.89	$1.98	$2.46	$2.58	$2.46	$2.58	0	430	430			
AUG	$1.88	$1.97	$2.48	$2.61	$2.48	$2.61	0	430	430			
SEP93	$1.86	$1.95	$2.41	$2.54	$2.41	$2.54	0	430	430			
OCT93	$1.97	$2.08	$2.52	$2.66	$2.34	$2.47	135	280	415			
NOV	$2.31	$2.45	$2.71	$2.86	$2.54	$2.69	192	255	447			
DEC	$2.64	$2.81	$2.84	$3.01	$2.77	$2.93	145	255	400			
1992	$1.97	$2.02	$2.15	$2.19	$2.12	$2.16	93	332	425			
1993	$2.14	$2.26	$2.43	$2.54	$2.38	$2.50	61	332	393			
1994	$2.30	$2.49	$2.62	$2.82	$2.57	$2.77	64	332	396			
1995	$2.44	$2.72	$2.82	$3.13	$2.77	$3.08	46	332	378	$2.70	$2.92	200
1996	$2.53	$2.93	$2.90	$3.33	$2.85	$3.27	53	332	385	$2.84	$3.15	200

	PHASE I & II & III VOLUMES									SPOT/MARKET GAS @ USGC $/MMBTU	
	NON-FIRM SERVICE		FIRM SERVICE		SYSTEM WEIGHTED AVERAGE		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY				
DATE	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL
JAN 92	$1.68	$1.69	$1.81	$1.82	$1.79	$1.80	52	255	307	$1.19	$1.20
FEB	$1.68	$1.70	$1.89	$1.90	$1.83	$1.84	102	255	357	$1.19	$1.20
MAR	$1.63	$1.65	$1.94	$1.96	$1.83	$1.85	147	255	402	$1.14	$1.15
APR92	$1.68	$1.71	$1.92	$1.94	$1.83	$1.86	157	280	437	$1.19	$1.20
MAY92	$1.72	$1.75	$1.91	$1.94	$1.91	$1.94	6	430	436	$1.23	$1.25
JUN	$1.72	$1.75	$2.05	$2.08	$2.05	$2.08	6	430	436	$1.23	$1.25
JULY	$1.77	$1.81	$2.24	$2.28	$2.24	$2.28	27	430	457	$1.28	$1.30
AUG	$1.82	$1.86	$2.30	$2.35	$2.30	$2.35	0	430	430	$1.32	$1.35
SEP192	$1.87	$1.91	$2.21	$2.26	$2.21	$2.26	22	430	452	$1.37	$1.40
OCT92	$2.06	$2.12	$2.40	$2.46	$2.27	$2.33	179	280	459	$1.56	$1.60
NOV	$2.26	$2.33	$2.55	$2.63	$2.41	$2.48	233	255	488	$1.75	$1.80
DEC	$2.35	$2.43	$2.65	$2.73	$2.52	$2.60	190	255	445	$1.84	$1.90
JAN93	$2.35	$2.43	$2.61	$2.70	$2.61	$2.70	0	255	255	$1.84	$1.90
FEB	$2.11	$2.19	$2.48	$2.57	$2.42	$2.51	48	255	303	$1.61	$1.67
MAR	$1.84	$1.91	$2.26	$2.35	$2.14	$2.23	97	255	352	$1.34	$1.39
APR93	$1.69	$1.76	$2.17	$2.26	$2.03	$2.12	111	280	391	$1.20	$1.25
MAY	$1.66	$1.73	$2.12	$2.21	$2.12	$2.21	0	430	430	$1.17	$1.22
JUN	$1.82	$1.91	$2.29	$2.40	$2.29	$2.40	0	430	430	$1.33	$1.39
JUL	$1.89	$1.98	$2.46	$2.58	$2.46	$2.58	9	430	430	$1.40	$1.46
AUG	$1.88	$1.97	$2.48	$2.61	$2.48	$2.61	0	430	430	$1.38	$1.45
SEP93	$1.86	$1.95	$2.41	$2.54	$2.41	$2.54	0	430	430	$1.36	$1.43
OCT93	$1.97	$2.08	$2.52	$2.66	$2.34	$2.47	135	280	415	$1.47	$1.55
NOV	$2.31	$2.45	$2.71	$2.86	$2.54	$2.69	192	255	447	$1.81	$1.91
DEC	$2.64	$2.81	$2.84	$3.01	$2.77	$2.93	145	255	400	$2.13	$2.26
1992	$1.97	$2.02	$2.15	$2.19	$2.12	$2.16	93	332	425	$1.36	$1.38
1993	$2.14	$2.26	$2.43	$2.54	$2.38	$2.50	61	332	393	$1.50	$1.57
1994	$2.30	$2.49	$2.62	$2.82	$2.57	$2.77	64	332	396	$1.65	$1.78
1995	$2.44	$2.72	$2.78	$3.05	$2.75	$3.02	46	532	578	$1.79	$1.99
1996	$2.53	$2.93	$2.88	$3.26	$2.84	$3.23	53	532	585	$1.93	$2.21

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D 1 9 9 1 D O L L A R & N O M I N A L D O L L A R N A T U R A L G A S P R I C E S I N D O L L A R S
P E R M M B T U & N A T U R A L G A S A V A I L A B I L I T Y I N M I L L I O N S O F C U B I C F E E T P E R D A Y
JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	**********************P H A S E I & II V O L U M E S***********************									***********PHASE III**********		
	*****NON-FIRM**** *****SERVICE*****		******FIRM****** ****SERVICE*****		****SYSTEM***** ***WEIGHTED**** ****AVERAGE****		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY			FIRM SERVICE		FIRM NATURAL GAS AVAILABILITY
	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL	MMCF/DAY
JAN94	$2.52	$2.68	$2.88	$3.06	$2.88	$3.06	0	255	255			
FEB	$2.31	$2.47	$2.68	$2.86	$2.61	$2.79	55	255	310			
MAR	$2.01	$2.15	$2.48	$2.65	$2.35	$2.51	104	255	359			
APR94	$1.82	$1.94	$2.39	$2.56	$2.22	$2.38	116	280	396			
MAY 94	$1.78	$1.91	$2.34	$2.51	$2.34	$2.51	0	430	430			
JUN	$1.96	$2.11	$2.48	$2.67	$2.48	$2.67	0	430	430			
JUL	$2.03	$2.18	$2.62	$2.82	$2.62	$2.82	0	430	430			
AUG	$2.00	$2.16	$2.63	$2.85	$2.63	$2.85	0	430	430			
SEP94	$1.99	$2.15	$2.56	$2.77	$2.56	$2.77	0	430	430			
OCT94	$2.10	$2.28	$2.70	$2.94	$2.50	$2.72	141	280	421			
NOV	$2.48	$2.70	$2.92	$3.18	$2.73	$2.97	197	255	452			
DEC	$2.83	$3.09	$3.09	$3.38	$2.99	$3.27	151	255	406			
JAN95	$2.63	$2.88	$3.15	$3.45	$3.15	$3.45	0	255	255	$3.04	$3.25	200
FEB	$2.44	$2.67	$2.92	$3.20	$2.85	$3.13	41	255	296	$2.85	$3.04	200
MAR	$2.16	$2.37	$2.69	$2.96	$2.57	$2.82	75	255	330	$2.57	$2.74	200
APR95	$1.94	$2.14	$2.59	$2.86	$2.44	$2.69	83	280	363	$2.35	$2.51	200
MAY	$1.91	$2.11	$2.50	$2.76	$2.50	$2.76	0	430	430	$2.32	$2.48	200
JUN	$2.10	$2.32	$2.66	$2.94	$2.66	$2.94	0	430	430	$2.50	$2.69	200
JUL	$2.15	$2.39	$2.84	$3.16	$2.84	$3.16	0	430	430	$2.56	$2.75	200
AUG	$2.05	$2.29	$2.80	$3.12	$2.80	$3.12	0	430	430	$2.52	$2.72	200
SEP95	$2.04	$2.29	$2.69	$3.01	$2.69	$3.01	0	430	430	$2.52	$2.72	200
OCT95	$2.17	$2.43	$2.90	$3.25	$2.70	$3.03	101	280	381	$2.64	$2.86	200
NOV	$2.57	$2.90	$3.15	$3.54	$2.94	$3.31	142	255	397	$3.05	$3.33	200
DEC	$3.08	$3.48	$3.37	$3.80	$3.28	$3.70	109	255	364	$3.55	$3.90	200
JAN96	$2.87	$3.25	$3.35	$3.79	$3.35	$3.79	0	255	255	$3.34	$3.67	200
FEB	$2.53	$2.88	$2.98	$3.38	$2.90	$3.29	52	255	307	$3.01	$3.30	200
MAR	$2.23	$2.54	$2.73	$3.10	$2.60	$2.96	87	255	342	$2.70	$2.96	200
APR96	$2.00	$2.28	$2.62	$2.99	$2.46	$2.81	95	280	375	$2.47	$2.70	200
MAY96	$1.97	$2.25	$2.52	$2.88	$2.52	$2.88	0	430	430	$2.44	$2.67	200
JUN	$2.16	$2.48	$2.70	$3.10	$2.70	$3.10	0	430	430	$2.63	$2.90	200
JUL	$2.22	$2.56	$2.89	$3.33	$2.89	$3.33	0	430	430	$2.69	$2.97	200
AUG	$2.18	$2.52	$2.91	$3.36	$2.91	$3.36	0	430	430	$2.65	$2.94	200
SEP96	$2.17	$2.52	$2.80	$3.24	$2.80	$3.24	0	430	430	$2.64	$2.93	200
OCT96	$2.30	$2.67	$3.01	$3.49	$2.80	$3.25	117	280	397	$2.77	$3.09	200
NOV	$2.72	$3.18	$3.26	$3.80	$3.06	$3.56	157	255	412	$3.20	$3.59	200
DEC	$3.12	$3.65	$3.46	$4.04	$3.35	$3.91	127	255	382	$3.59	$4.06	200

DATE	****************P H A S E I & II & III V O L U M E S****************									SPOT/MARKET GAS @ USGC $/MMBTU	
	*****NON-FIRM**** *****SERVICE*****		******FIRM****** ****SERVICE*****		****SYSTEM***** ***WEIGHTED**** ****AVERAGE****		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY				
	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL
JAN94	$2.52	$2.68	$2.88	$3.06	$2.88	$3.06	0	255	255	$2.01	$2.13
FEB	$2.31	$2.47	$2.68	$2.86	$2.61	$2.79	55	255	310	$1.81	$1.93
MAR	$2.01	$2.15	$2.48	$2.65	$2.35	$2.51	104	255	359	$1.51	$1.62
APR94	$1.82	$1.94	$2.39	$2.56	$2.22	$2.38	116	280	396	$1.32	$1.41
MAY 94	$1.78	$1.91	$2.34	$2.51	$2.34	$2.51	0	430	430	$1.29	$1.39
JUN	$1.96	$2.11	$2.48	$2.67	$2.48	$2.67	0	430	430	$1.46	$1.57
JUL	$2.03	$2.18	$2.62	$2.82	$2.62	$2.82	0	430	430	$1.52	$1.64
AUG	$2.00	$2.16	$2.63	$2.85	$2.63	$2.85	0	430	430	$1.50	$1.62
SEP94	$1.99	$2.15	$2.56	$2.77	$2.56	$2.77	0	430	430	$1.49	$1.61
OCT94	$2.10	$2.28	$2.70	$2.94	$2.50	$2.72	141	280	421	$1.60	$1.74
NOV	$2.48	$2.70	$2.92	$3.18	$2.73	$2.97	197	255	452	$1.97	$2.14
DEC	$2.83	$3.09	$3.09	$3.38	$2.99	$3.27	151	255	406	$2.31	$2.52
JAN95	$2.63	$2.88	$3.10	$3.37	$3.10	$3.37	0	455	455	$2.12	$2.32
FEB	$2.44	$2.67	$2.89	$3.13	$2.85	$3.10	41	455	496	$1.93	$2.11
MAR	$2.16	$2.37	$2.63	$2.86	$2.57	$2.79	75	455	530	$1.66	$1.82
APR95	$1.94	$2.14	$2.49	$2.71	$2.41	$2.62	83	480	563	$1.44	$1.59
MAY	$1.91	$2.11	$2.44	$2.67	$2.44	$2.67	0	630	630	$1.41	$1.56
JUN	$2.10	$2.32	$2.61	$2.86	$2.61	$2.86	0	630	630	$1.59	$1.77
JUL	$2.15	$2.39	$2.75	$3.03	$2.75	$3.03	0	630	630	$1.65	$1.83
AUG	$2.05	$2.29	$2.71	$2.99	$2.71	$2.99	0	630	630	$1.61	$1.80
SEP95	$2.04	$2.29	$2.64	$2.92	$2.64	$2.92	0	630	630	$1.61	$1.80
OCT95	$2.17	$2.43	$2.79	$3.09	$2.68	$2.97	101	480	581	$1.72	$1.93
NOV	$2.57	$2.90	$3.10	$3.44	$2.98	$3.32	142	455	597	$2.12	$2.39
DEC	$3.08	$3.48	$3.45	$3.84	$3.38	$3.77	109	455	564	$2.61	$2.95
JAN96	$2.87	$3.25	$3.35	$3.74	$3.35	$3.74	0	455	455	$2.41	$2.72
FEB	$2.53	$2.88	$2.99	$3.34	$2.94	$3.30	52	455	507	$2.08	$2.36
MAR	$2.23	$2.54	$2.71	$3.04	$2.64	$2.96	87	455	542	$1.78	$2.03
APR96	$2.00	$2.28	$2.55	$2.87	$2.46	$2.77	95	480	575	$1.56	$1.78
MAY96	$1.97	$2.25	$2.49	$2.81	$2.49	$2.81	0	630	630	$1.53	$1.75
JUN	$2.16	$2.48	$2.68	$3.03	$2.68	$3.03	0	630	630	$1.72	$1.97
JUL	$2.22	$2.56	$2.83	$3.21	$2.83	$3.21	0	630	630	$1.78	$2.04
AUG	$2.18	$2.52	$2.83	$3.22	$2.83	$3.22	0	630	630	$1.74	$2.01
SEP96	$2.17	$2.52	$2.75	$3.14	$2.75	$3.14	0	630	630	$1.73	$2.00
OCT96	$2.30	$2.67	$2.91	$3.32	$2.79	$3.20	117	480	597	$1.86	$2.15
NOV	$2.72	$3.18	$3.23	$3.70	$3.10	$3.57	157	455	612	$2.27	$2.64
DEC	$3.12	$3.65	$3.52	$4.05	$3.43	$3.96	127	455	582	$2.65	$3.10

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

D E L I V E R E D 1 9 9 1 D O L L A R & N O M I N A L D O L L A R C O A L P R I C E S I N D O L L A R S P E R T O N &
P E R M M B T U

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	ST. JOHNS RIVER POWER PARK COAL WEIGHTED AVERAGE PRICE NOMINAL $/TON	$/MMBTU	SPOT PRICE NOMINAL $/TON	$/MMBTU	SCHERER UNIT 4 WEIGHTED AVERAGE PRICE NOMINAL $/TON	$/MMBTU	ORIMULSION DELIVERED TO SANFORD NOMINAL $/TON	$/MMBTU
JAN 92	$44.09	$1.80	$38.54	$1.61	$59.65	$2.42	$48.63	$1.90
FEB	$45.05	$1.83	$38.54	$1.61	$53.46	$2.16	$49.36	$1.93
MAR	$45.05	$1.83	$38.54	$1.61	$49.85	$2.01	$49.36	$1.93
APR92	$44.62	$1.82	$39.01	$1.63	$47.32	$1.91	$49.20	$1.92
MAY92	$45.12	$1.83	$39.01	$1.63	$49.36	$1.99	$49.50	$1.93
JUN	$43.70	$1.79	$38.96	$1.62	$49.21	$1.99	$48.22	$1.88
JULY	$42.75	$1.75	$39.43	$1.64	$47.09	$1.90	$47.38	$1.85
AUG	$43.40	$1.78	$38.83	$1.62	$46.84	$1.89	$47.99	$1.87
SEP92	$42.94	$1.75	$38.15	$1.59	$48.88	$1.97	$47.39	$1.85
OCT92	$43.49	$1.78	$37.92	$1.58	$46.86	$1.89	$47.97	$1.87
NOV	$43.71	$1.77	$37.22	$1.55	$55.53	$2.25	$47.89	$1.87
DEC	$40.88	$1.67	$35.96	$1.50	$53.06	$2.14	$45.09	$1.76
JAN93	$42.45	$1.73	$40.50	$1.69	$59.18	$2.40	$46.89	$1.83
FEB	$42.51	$1.73	$40.54	$1.69	$59.18	$2.40	$46.83	$1.83
MAR	$42.59	$1.74	$40.57	$1.69	$56.02	$2.29	$46.92	$1.83
APR93	$42.72	$1.75	$40.61	$1.69	$50.19	$2.07	$47.18	$1.84
MAY 93	$42.76	$1.74	$40.65	$1.69	$51.43	$2.11	$47.10	$1.84
JUN	$42.69	$1.74	$40.53	$1.69	$51.75	$2.13	$47.02	$1.84
JUL	$42.57	$1.74	$40.31	$1.68	$50.80	$2.09	$47.01	$1.84
AUG	$42.31	$1.72	$40.06	$1.67	$50.36	$2.07	$46.61	$1.82
SEP93	$41.69	$1.70	$39.39	$1.64	$51.97	$2.14	$45.92	$1.79
OCT93	$41.13	$1.68	$38.72	$1.61	$49.55	$2.04	$45.43	$1.77
NOV	$40.28	$1.64	$37.88	$1.58	$61.04	$2.48	$44.38	$1.73
DEC	$38.89	$1.58	$36.45	$1.52	$61.04	$2.48	$42.86	$1.67
1992	$43.73	$1.78	$38.34	$1.60	$50.59	$2.04	$48.17	$1.88
1993	$41.88	$1.71	$39.68	$1.65	$54.37	$2.23	$46.18	$1.80
1994	$43.16	$1.76	$41.19	$1.72	$55.26	$2.25	$47.66	$1.86
1995	$44.45	$1.82	$43.51	$1.81	$50.86	$2.10	$49.04	$1.92
1996	$45.48	$1.86	$45.44	$1.89	$51.94	$2.16	$50.25	$1.96

JANUARY 1992 TO DECEMBER 1996 FPL/DRI SHORT-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

DELIVERED 1991 DOLLAR & NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON & PER MMBTU

JANUARY 10, 1992/FEBRUARY 4, 1992

DATE	ST. JOHNS RIVER POWER PARK COAL WEIGHTED AVERAGE PRICE NOMINAL $/TON	$/MMBTU	SPOT PRICE NOMINAL $/TON	$/MMBTU	SCHERER UNIT 4 WEIGHTED AVERAGE PRICE NOMINAL $/TON	$/MMBTU	ORIMULSION DELIVERED TO SANFORD NOMINAL $/TON	$/MMBTU
JAN94	$43.63	$1.79	$41.78	$1.74	$58.05	$2.35	$48.26	$1.89
FEB	$43.71	$1.79	$41.84	$1.74	$58.05	$2.35	$48.23	$1.88
MAR	$43.80	$1.79	$41.90	$1.75	$58.05	$2.35	$48.32	$1.89
APR94	$43.89	$1.80	$41.96	$1.75	$52.36	$2.15	$48.53	$1.90
MAY 94	$43.96	$1.80	$42.02	$1.75	$55.58	$2.27	$48.49	$1.89
JUN	$43.93	$1.79	$41.96	$1.75	$54.22	$2.22	$48.45	$1.89
JUL	$43.78	$1.79	$41.78	$1.74	$52.35	$2.15	$48.41	$1.89
AUG	$43.56	$1.78	$41.56	$1.73	$51.56	$2.12	$48.05	$1.88
SEP94	$43.04	$1.76	$41.02	$1.71	$54.47	$2.22	$47.48	$1.85
OCT94	$42.46	$1.74	$40.38	$1.68	$51.52	$2.12	$46.97	$1.83
NOV	$41.73	$1.70	$39.66	$1.65	$58.45	$2.37	$46.05	$1.80
DEC	$40.46	$1.65	$38.37	$1.60	$58.45	$2.37	$44.67	$1.74
JAN95	$44.80	$1.83	$44.03	$1.83	$55.23	$2.25	$49.51	$1.93
FEB	$44.94	$1.84	$44.10	$1.84	$52.55	$2.16	$49.54	$1.94
MAR	$45.04	$1.84	$44.18	$1.84	$50.92	$2.10	$49.65	$1.94
APR95	$45.11	$1.85	$44.25	$1.84	$52.76	$2.17	$49.84	$1.95
MAY 95	$45.24	$1.85	$44.33	$1.85	$52.41	$2.16	$49.86	$1.95
JUN	$45.22	$1.85	$44.28	$1.85	$49.19	$2.04	$49.84	$1.95
JUL	$45.05	$1.85	$44.11	$1.84	$49.34	$2.05	$49.77	$1.94
AUG	$44.89	$1.83	$43.91	$1.83	$49.44	$2.05	$49.48	$1.93
SEP95	$44.39	$1.81	$43.38	$1.81	$49.58	$2.06	$48.92	$1.91
OCT95	$43.79	$1.79	$42.76	$1.78	$49.49	$2.06	$48.39	$1.89
NOV	$43.11	$1.76	$42.05	$1.75	$49.63	$2.06	$47.53	$1.86
DEC	$41.86	$1.71	$40.78	$1.70	$49.76	$2.07	$46.16	$1.80
JAN96	$45.60	$1.87	$45.81	$1.91	$51.20	$2.13	$50.47	$1.97
FEB	$45.88	$1.88	$45.89	$1.91	$51.32	$2.14	$50.65	$1.98
MAR	$45.99	$1.88	$45.98	$1.92	$51.45	$2.14	$50.77	$1.98
APR96	$45.94	$1.89	$46.06	$1.92	$51.61	$2.15	$50.84	$1.99
MAY96	$46.21	$1.89	$46.15	$1.92	$51.73	$2.15	$51.00	$1.99
JUN	$46.24	$1.89	$46.15	$1.92	$51.86	$2.16	$51.03	$1.99
JUL	$45.96	$1.89	$46.00	$1.92	$52.03	$2.16	$50.85	$1.99
AUG	$45.94	$1.88	$45.81	$1.91	$52.15	$2.17	$50.70	$1.98
SEP96	$45.55	$1.86	$45.40	$1.89	$52.28	$2.18	$50.28	$1.96
OCT96	$44.85	$1.84	$44.81	$1.87	$52.43	$2.18	$49.64	$1.94
NOV	$44.33	$1.81	$44.13	$1.84	$52.56	$2.19	$48.94	$1.91
DEC	$43.29	$1.77	$43.06	$1.79	$52.69	$2.19	$47.80	$1.87

1992 TO 2021 FPL SHORT-TERM/ DRI 4091 BASE CASE LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

C O N S T A N T   1 9 9 1   D O L L A R   &   N O M I N A L   D O L L A R   C R U D E   O I L   &   F U E L   O I L   P R I C E S

FEBRUARY 4, 1992

	CRUDE OIL PRICE								1.0% S RESIDUAL FUEL OIL @ US GULF COAST "PLATT'S" LOW POSTING @ US GULF COAST			
	ARABIAN LIGHT				WEST TEXAS INTERMEDIATE							
	$/BBL		$/MMBTU		$/BBL		$/MMBTU		$/BBL		$/MMBTU	
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL
1992	$16.50	$16.82	$2.84	$2.88	$19.27	$19.82	$3.32	$3.42	$13.30	$13.56	$2.12	$2.13
1993	$17.50	$18.33	$3.02	$3.14	$20.19	$21.33	$3.48	$3.68	$15.57	$16.31	$2.48	$2.56
1994	$19.00	$20.48	$3.28	$3.51	$21.59	$23.48	$3.72	$4.05	$17.42	$18.78	$2.77	$2.95
1995	$20.75	$23.25	$3.58	$4.01	$23.26	$26.06	$4.01	$4.49	$19.58	$21.77	$3.11	$3.42
1996	$21.66	$25.09	$3.73	$4.33	$24.75	$28.67	$4.27	$4.94	$20.38	$23.43	$3.24	$3.68
1997	$23.62	$28.33	$4.07	$4.89	$27.21	$32.64	$4.69	$5.63	$21.11	$25.32	$3.36	$4.03
1998	$24.60	$30.54	$4.24	$5.27	$28.34	$35.18	$4.89	$6.07	$22.02	$27.34	$3.50	$4.35
1999	$25.88	$33.27	$4.46	$5.74	$29.85	$38.37	$5.15	$6.62	$23.23	$29.86	$3.69	$4.75
2000	$27.29	$36.44	$4.71	$6.28	$31.50	$42.06	$5.43	$7.25	$24.49	$32.70	$3.90	$5.20
2001	$28.75	$39.95	$4.96	$6.89	$33.20	$46.13	$5.72	$7.95	$25.77	$35.81	$4.10	$5.70
2002	$30.06	$43.47	$5.18	$7.49	$34.75	$50.25	$5.99	$8.66	$26.99	$39.03	$4.29	$6.21
2003	$31.13	$46.84	$5.37	$8.08	$36.02	$54.20	$6.21	$9.35	$27.99	$42.12	$4.45	$6.70
2004	$31.95	$50.05	$5.51	$8.63	$36.99	$57.94	$6.38	$9.99	$28.76	$45.05	$4.57	$7.17
2005	$32.68	$53.30	$5.63	$9.19	$37.85	$61.73	$6.53	$10.64	$29.53	$48.16	$4.70	$7.66
2006	$33.40	$56.70	$5.76	$9.78	$38.72	$65.74	$6.68	$11.33	$30.29	$51.42	$4.82	$8.18
2007	$34.09	$60.30	$5.88	$10.40	$39.57	$70.00	$6.82	$12.07	$30.98	$54.80	$4.93	$8.72
2008	$34.74	$64.05	$5.99	$11.04	$40.39	$74.47	$6.96	$12.84	$31.68	$58.41	$5.04	$9.29
2009	$35.36	$68.02	$6.10	$11.73	$41.17	$79.20	$7.10	$13.65	$32.35	$62.23	$5.15	$9.90
2010	$35.92	$72.08	$6.19	$12.43	$41.86	$84.00	$7.22	$14.48	$32.89	$66.00	$5.23	$10.50
2011	$36.24	$75.88	$6.25	$13.08	$43.19	$90.44	$7.45	$15.59	$33.24	$69.60	$5.29	$11.07
2012	$36.61	$80.12	$6.31	$13.81	$43.61	$95.44	$7.52	$16.46	$33.57	$73.47	$5.34	$11.69
2013	$36.97	$84.65	$6.37	$14.60	$44.03	$100.82	$7.59	$17.38	$33.89	$77.60	$5.39	$12.34
2014	$37.34	$89.56	$6.44	$15.44	$44.45	$106.61	$7.66	$18.38	$34.23	$82.10	$5.44	$13.06
2015	$37.71	$94.76	$6.50	$16.34	$45.06	$113.23	$7.77	$19.52	$34.74	$87.30	$5.53	$13.89
2016	$38.09	$100.28	$6.57	$17.29	$45.63	$120.13	$7.87	$20.71	$35.23	$92.75	$5.60	$14.75
2017	$38.43	$106.01	$6.63	$18.28	$46.22	$127.49	$7.97	$21.98	$35.73	$98.56	$5.68	$15.68
2018	$38.76	$112.02	$6.68	$19.31	$46.83	$135.34	$8.07	$23.33	$36.25	$104.76	$5.77	$16.66
2019	$39.07	$118.30	$6.74	$20.40	$47.46	$143.71	$8.18	$24.78	$36.79	$111.40	$5.85	$17.72
2020	$39.36	$124.87	$6.79	$21.53	$48.09	$152.56	$8.29	$26.30	$37.33	$118.43	$5.94	$18.84
2021	$39.64	$131.76	$6.83	$22.72	$48.52	$161.27	$8.37	$27.81	$37.70	$125.31	$6.00	$19.93

1992 TO 2021 FPL SHORT TERM/ DRI 4Q91 BASE CASE LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

D E L I V E R E D   C O N S T A N T   1 9 9 1   D O L L A R   &   N O M I N A L   D O L L A R   F U E L   O I L   P R I C E S   I N   D O L L A R S   P E R   B A R R E L   &   P E R   M M B T U

FEBRUARY 4, 1992

YEAR	0.3% SULFUR FUEL OIL $/BBL 1991$	0.3% $/BBL NOMINAL	0.3% $/MMBTU 1991$	0.3% $/MMBTU NOMINAL	0.7% SULFUR FUEL OIL $/BBL 1991$	0.7% $/BBL NOMINAL	0.7% $/MMBTU 1991$	0.7% $/MMBTU NOMINAL	1.0% SULFUR FUEL OIL $/BBL 1991$	1.0% $/BBL NOMINAL	1.0% $/MMBTU 1991$	1.0% $/MMBTU NOMINAL	1.5% SULFUR FUEL OIL $/BBL 1991$	1.5% $/BBL NOMINAL	1.5% $/MMBTU 1991$	1.5% $/MMBTU NOMINAL
1992	$16.16	$16.62	$2.57	$2.64	$15.28	$15.55	$2.43	$2.44	$14.54	$14.80	$2.31	$2.33	$14.03	$14.28	$2.23	$2.25
1993	$17.97	$18.99	$2.86	$3.02	$17.66	$18.44	$2.81	$2.90	$16.81	$17.56	$2.67	$2.76	$16.17	$16.88	$2.57	$2.66
1994	$19.94	$21.68	$3.17	$3.45	$19.59	$21.04	$3.12	$3.30	$18.66	$20.03	$2.97	$3.14	$17.89	$19.21	$2.84	$3.02
1995	$22.11	$24.77	$3.52	$3.94	$21.42	$23.69	$3.41	$3.72	$20.82	$23.02	$3.31	$3.61	$20.16	$22.29	$3.20	$3.50
1996	$23.29	$26.98	$3.70	$4.29	$22.36	$25.55	$3.56	$4.01	$21.62	$24.69	$3.44	$3.88	$20.69	$23.63	$3.28	$3.71
1997	$24.24	$29.08	$3.86	$4.63	$23.16	$27.78	$3.68	$4.42	$22.35	$26.81	$3.56	$4.26	$21.01	$25.20	$3.34	$4.01
1998	$25.52	$31.68	$4.06	$5.04	$24.23	$30.08	$3.85	$4.78	$23.26	$28.87	$3.70	$4.59	$21.65	$26.88	$3.44	$4.27
1999	$27.09	$34.82	$4.31	$5.54	$25.59	$32.89	$4.07	$5.23	$24.47	$31.45	$3.89	$5.00	$22.60	$29.05	$3.59	$4.62
2000	$28.72	$38.35	$4.57	$6.10	$27.01	$36.07	$4.30	$5.74	$25.73	$34.36	$4.09	$5.46	$23.59	$31.50	$3.75	$5.01
2001	$30.00	$41.69	$4.77	$6.63	$28.29	$39.31	$4.50	$6.25	$27.01	$37.53	$4.30	$5.97	$24.87	$34.56	$3.96	$5.50
2002	$31.22	$45.15	$4.97	$7.18	$29.51	$42.67	$4.69	$6.79	$28.23	$40.82	$4.49	$6.49	$26.09	$37.75	$4.15	$6.00
2003	$32.22	$48.48	$5.12	$7.71	$30.51	$45.91	$4.85	$7.30	$29.23	$43.98	$4.65	$7.00	$27.09	$40.76	$4.31	$6.48
2004	$32.99	$51.68	$5.25	$8.22	$31.28	$49.00	$4.98	$7.79	$30.00	$46.99	$4.77	$7.47	$27.86	$43.64	$4.43	$6.94
2005	$33.76	$55.06	$5.37	$8.76	$32.05	$52.27	$5.10	$8.31	$30.77	$50.19	$4.89	$7.98	$28.63	$46.69	$4.55	$7.43
2006	$34.52	$58.61	$5.49	$9.32	$32.81	$55.70	$5.22	$8.86	$31.53	$53.53	$5.02	$8.51	$29.39	$49.90	$4.67	$7.94
2007	$35.22	$62.30	$5.60	$9.91	$33.51	$59.28	$5.33	$9.43	$32.22	$56.99	$5.12	$9.07	$30.09	$53.23	$4.79	$8.47
2008	$35.91	$66.21	$5.71	$10.53	$34.20	$63.06	$5.44	$10.03	$32.92	$60.70	$5.24	$9.65	$30.78	$56.75	$4.90	$9.03
2009	$36.58	$70.37	$5.82	$11.19	$34.87	$67.08	$5.55	$10.67	$33.59	$64.62	$5.34	$10.28	$31.45	$60.50	$5.00	$9.62
2010	$37.13	$74.51	$5.91	$11.85	$35.42	$71.07	$5.63	$11.30	$34.13	$68.49	$5.43	$10.89	$32.00	$64.21	$5.09	$10.21
2011	$37.47	$78.46	$5.96	$12.48	$35.76	$74.88	$5.69	$11.91	$34.48	$72.20	$5.48	$11.48	$32.34	$67.72	$5.14	$10.77
2012	$37.80	$82.73	$6.01	$13.16	$36.09	$78.99	$5.74	$12.56	$34.81	$76.18	$5.54	$12.12	$32.67	$71.50	$5.20	$11.37
2013	$38.13	$87.31	$6.06	$13.89	$36.42	$83.40	$5.79	$13.26	$35.13	$80.44	$5.59	$12.79	$33.00	$75.56	$5.25	$12.02
2014	$38.46	$92.24	$6.12	$14.67	$36.75	$88.14	$5.85	$14.02	$35.47	$85.07	$5.64	$13.53	$33.53	$79.94	$5.30	$12.71
2015	$38.98	$97.95	$6.20	$15.58	$37.27	$93.65	$5.93	$14.90	$35.98	$90.41	$5.72	$14.38	$33.85	$85.06	$5.38	$13.53
2016	$39.46	$103.89	$6.28	$16.52	$37.75	$99.39	$6.00	$15.81	$36.47	$96.02	$5.80	$15.27	$34.33	$90.38	$5.46	$14.38
2017	$39.96	$110.23	$6.36	$17.53	$38.25	$105.51	$6.08	$16.78	$36.97	$101.98	$5.88	$16.22	$34.83	$96.08	$5.54	$15.28
2018	$40.48	$116.99	$6.44	$18.61	$38.77	$112.05	$6.17	$17.82	$37.49	$108.35	$5.96	$17.23	$35.35	$102.16	$5.62	$16.25
2019	$41.02	$124.21	$6.52	$19.76	$39.31	$119.03	$6.25	$18.93	$38.03	$115.15	$6.05	$18.32	$35.89	$108.67	$5.71	$17.29
2020	$41.56	$131.85	$6.61	$20.97	$39.85	$126.42	$6.34	$20.11	$38.57	$122.36	$6.13	$19.46	$36.43	$115.57	$5.79	$18.38
2021	$41.93	$139.37	$6.67	$22.17	$40.22	$133.69	$6.40	$21.26	$38.94	$129.43	$6.19	$20.59	$36.80	$122.32	$5.85	$19.46

1992 TO 2021 FPL SHORT-TERM/ DRI 4Q91 BASE CASE LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED CONSTANT 1991 DOLLAR & NOMINAL DOLLAR FUEL OIL & ORIMULSION PRICES IN DOLLARS PER BARREL, PER MMBTU, & TON

FEBRUARY 4, 1992

	DISTILLATE FUEL OIL				3.0% SULFUR FUEL OIL				ORIMULSION	
	$/BBL		$/MMBTU		$/BBL		$/MMBTU		$/TON	$/MMBTU
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NOMINAL	NOMINAL
1992	$23.15	$23.58	$3.97	$4.04	$11.21	$11.41	$1.78	$1.80	$48.17	$1.88
1993	$24.83	$25.97	$4.26	$4.45	$12.92	$13.48	$2.06	$2.13	$46.18	$1.80
1994	$26.84	$28.86	$4.61	$4.95	$14.30	$15.34	$2.27	$2.41	$47.66	$1.86
1995	$29.12	$32.25	$5.00	$5.53	$17.54	$19.37	$2.79	$3.04	$49.04	$1.92
1996	$30.02	$34.36	$5.15	$5.90	$17.28	$19.70	$2.75	$3.09	$50.25	$1.96
1997	$30.29	$36.34	$5.20	$6.24	$16.97	$20.36	$2.70	$3.24	$52.87	$2.07
1998	$31.52	$39.13	$5.41	$6.72	$16.83	$20.89	$2.68	$3.32	$55.28	$2.16
1999	$33.15	$42.61	$5.69	$7.32	$16.97	$21.81	$2.70	$3.47	$56.50	$2.21
2000	$34.87	$46.56	$5.99	$7.99	$17.18	$22.94	$2.73	$3.65	$59.50	$2.32
2001	$36.62	$50.89	$6.29	$8.74	$18.46	$25.65	$2.94	$4.08	$61.69	$2.41
2002	$38.29	$55.37	$6.57	$9.51	$19.68	$28.46	$3.13	$4.53	$64.77	$2.53
2003	$39.65	$59.66	$6.81	$10.24	$20.68	$31.12	$3.29	$4.95	$67.91	$2.65
2004	$40.71	$63.77	$6.99	$10.95	$21.45	$33.60	$3.41	$5.34	$70.58	$2.76
2005	$41.75	$68.09	$7.17	$11.69	$22.22	$36.24	$3.53	$5.76	$76.49	$2.99
2006	$42.78	$72.63	$7.34	$12.47	$22.98	$39.01	$3.66	$6.21	$79.44	$3.10
2007	$43.73	$77.35	$7.51	$13.28	$23.67	$41.87	$3.76	$6.66	$82.63	$3.23
2008	$44.67	$82.36	$7.67	$14.14	$24.37	$44.93	$3.88	$7.15	$85.98	$3.36
2009	$45.58	$87.68	$7.82	$15.05	$25.04	$48.17	$3.98	$7.66	$89.54	$3.50
2010	$46.32	$92.95	$7.95	$15.96	$25.58	$51.33	$4.07	$8.16	$96.80	$3.78
2011	$46.79	$97.97	$8.03	$16.82	$25.93	$54.30	$4.12	$8.64	$100.77	$3.94
2012	$47.23	$103.37	$8.11	$17.75	$26.26	$57.47	$4.18	$9.14	$105.06	$4.10
2013	$47.68	$109.18	$8.19	$18.74	$26.58	$60.86	$4.23	$9.68	$109.62	$4.28
2014	$48.13	$115.44	$8.26	$19.82	$26.92	$64.57	$4.28	$10.27	$114.47	$4.47
2015	$48.83	$122.70	$8.38	$21.06	$27.43	$68.93	$4.36	$10.96	$122.68	$4.79
2016	$49.49	$130.30	$8.50	$22.37	$27.92	$73.51	$4.44	$11.69	$128.07	$5.00
2017	$50.17	$138.39	$8.61	$23.76	$28.42	$78.39	$4.52	$12.47	$133.74	$5.22
2018	$50.88	$147.05	$8.73	$25.24	$28.94	$83.64	$4.60	$13.30	$139.62	$5.45
2019	$51.61	$156.27	$8.86	$26.83	$29.48	$89.26	$4.69	$14.20	$145.79	$5.69
2020	$52.35	$166.08	$8.99	$28.51	$30.02	$95.24	$4.77	$15.15	$152.25	$5.95
2021	$52.85	$175.67	$9.07	$30.16	$30.39	$101.01	$4.83	$16.07	$159.02	$6.21

1992 TO 2021 FPL SHORT-TERM/ DRI 4091 BASE CASE LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1991 DOLLAR & NOMINAL DOLLAR PRICES

DELIVERED 1991 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU & NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY

FEBRUARY 4, 1992

	PHASE I & II VOLUMES									PHASE III		
	NON-FIRM SERVICE		FIRM SERVICE		SYSTEM WEIGHTED AVERAGE		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY			FIRM PRICE		FIRM NATURAL GAS AVAILABILITY
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL	MMCF/DAY
1992	$1.97	$2.02	$2.15	$2.19	$2.12	$2.16	93	332	425			
1993	$2.14	$2.26	$2.43	$2.54	$2.38	$2.50	61	332	393			
1994	$2.30	$2.49	$2.62	$2.82	$2.57	$2.77	64	332	396			
1995	$2.44	$2.72	$2.82	$3.13	$2.77	$3.08	46	332	378	$2.70	$2.92	200
1996	$2.53	$2.93	$2.90	$3.33	$2.85	$3.27	53	332	385	$2.84	$3.15	200
1997	$2.56	$3.07	$3.07	$3.68	$2.99	$3.58	63	332	395	$3.03	$3.48	200
1998	$2.75	$3.42	$3.21	$3.99	$3.14	$3.89	67	332	399	$3.23	$3.81	200
1999	$3.00	$3.85	$3.41	$4.38	$3.34	$4.29	68	332	400	$3.47	$4.23	200
2000	$3.25	$4.34	$3.61	$4.82	$3.55	$4.74	68	332	400	$3.72	$4.70	200
2001	$3.50	$4.86	$3.81	$5.29	$3.76	$5.22	68	332	400	$3.97	$5.20	200
2002	$3.74	$5.40	$4.00	$5.79	$3.96	$5.72	68	332	400	$4.21	$5.73	200
2003	$3.95	$5.95	$4.16	$6.26	$4.13	$6.21	68	332	400	$4.43	$6.25	200
2004	$4.15	$6.51	$4.29	$6.73	$4.27	$6.69	68	332	400	$4.63	$6.79	200
2005	$4.35	$7.09	$4.42	$7.21	$4.41	$7.19	68	332	400	$4.82	$7.36	200
2006	$4.58	$7.62			$4.58	$7.62	120	280	400	$5.03	$7.97	200
2007	$4.78	$8.28			$4.78	$8.28	120	280	400	$4.87	$8.61	200
2008	$4.98	$9.00			$4.98	$9.00	120	280	400	$4.97	$9.17	200
2009	$5.19	$9.79			$5.19	$9.79	120	280	400	$5.08	$9.76	200
2010	$5.39	$10.59			$5.39	$10.59	120	280	400	$5.16	$10.35	200
2011	$5.51	$11.30			$5.51	$11.30	120	280	400	$5.21	$10.91	200
2012	$5.61	$12.00			$5.61	$12.00	120	280	400	$5.26	$11.51	200
2013	$5.67	$12.69			$5.67	$12.69	120	280	400	$5.31	$12.16	200
2014	$5.72	$13.40			$5.72	$13.40	120	280	400	$5.36	$12.85	200
2015	$5.77	$14.28			$5.77	$14.28	120	280	400			
2016	$5.82	$15.08			$5.82	$15.08	120	280	400			
2017	$5.86	$15.91			$5.86	$15.91	120	280	400			
2018	$5.90	$16.78			$5.90	$16.78	120	280	400			
2019	$5.94	$17.70			$5.94	$17.70	120	280	400			
2020	$6.00	$18.70			$6.00	$18.70	120	280	400			
2021	$6.02	$19.65			$6.02	$19.65	120	280	400			

	PHASE I & II & III VOLUMES									MEMO: SPOT NATURAL GAS DELIVERED TO THE FGT SYSTEM @ USGC $/MMBTU	
	NON-FIRM SERVICE		FIRM SERVICE		SYSTEM WEIGHTED AVERAGE		NATURAL GAS AVAILABILITY MILLION CUBIC FEET PER DAY				
YEAR	1991$	NOMINAL	1991$	NOMINAL	1991$	NOMINAL	NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	1991$	NOMINAL
1992	$1.97	$2.02	$2.15	$2.19	$2.12	$2.16	93	332	425	$1.36	$1.38
1993	$2.14	$2.26	$2.43	$2.54	$?.38	$2.50	61	332	393	$1.50	$1.57
1994	$2.30	$2.49	$2.62	$2.82	$2.57	$2.77	64	332	396	$1.65	$1.78
1995	$2.44	$2.72	$2.78	$3.05	$2.75	$3.02	46	532	578	$1.79	$1.99
1996	$2.53	$2.93	$2.88	$3.26	$2.84	$3.23	53	532	585	$1.93	$2.21
1997	$2.56	$3.07	$3.05	$3.60	$3.00	$3.55	63	532	595	$2.10	$2.52
1998	$2.75	$3.42	$3.22	$3.92	$3.17	$3.87	67	532	599	$2.29	$2.85
1999	$3.00	$3.85	$3.43	$4.33	$3.38	$4.27	68	532	600	$2.53	$3.25
2000	$3.25	$4.34	$3.65	$4.77	$3.61	$4.73	68	532	600	$2.78	$3.71
2001	$3.50	$4.86	$3.87	$5.26	$3.83	$5.21	68	532	600	$3.02	$4.19
2002	$3.74	$5.40	$4.08	$5.76	$4.04	$5.72	68	532	600	$3.25	$4.70
2003	$3.95	$5.95	$4.26	$6.26	$4.23	$6.22	68	532	600	$3.46	$5.21
2004	$4.15	$6.51	$4.42	$6.75	$4.39	$6.72	68	532	600	$3.66	$5.73
2005	$4.35	$7.09	$4.57	$7.26	$4.55	$7.25	68	532	600	$3.85	$6.27
2006	$4.58	$7.62	$5.03	$7.97	$4.94	$7.90	120	480	600	$4.04	$6.86
2007	$4.78	$8.28	$4.87	$8.61	$4.85	$8.55	120	480	600	$4.24	$7.49
2008	$4.98	$9.00	$4.97	$9.17	$4.98	$9.14	120	480	600	$4.44	$8.18
2009	$5.19	$9.79	$5.08	$9.76	$5.10	$9.77	120	480	600	$4.64	$8.92
2010	$5.39	$10.59	$5.16	$10.35	$5.20	$10.40	120	480	600	$4.83	$9.69
2011	$5.51	$11.30	$5.21	$10.91	$5.27	$10.99	120	480	600	$4.95	$10.36
2012	$5.61	$12.00	$5.26	$11.51	$5.33	$11.61	120	480	600	$5.04	$11.03
2013	$5.67	$12.69	$5.31	$12.16	$5.38	$12.26	120	480	600	$5.10	$11.68
2014	$5.72	$13.40	$5.36	$12.85	$5.43	$12.96	120	480	600	$5.15	$12.35
2015	$5.77	$14.28	$5.77	$14.28	$5.77	$14.28	320	280	600	$5.21	$13.09
2016	$5.82	$15.08	$5.82	$15.08	$5.82	$15.08	320	280	600	$5.26	$13.85
2017	$5.86	$15.91	$5.86	$15.91	$5.86	$15.91	320	280	600	$5.30	$14.62
2018	$5.90	$16.78	$5.90	$16.78	$5.90	$16.78	320	280	600	$5.34	$15.43
2019	$5.94	$17.70	$5.94	$17.70	$5.94	$17.70	320	280	600	$5.38	$16.29
2020	$6.00	$18.70	$6.00	$18.70	$6.00	$18.70	320	280	600	$5.43	$17.23
2021	$6.02	$19.65	$6.02	$19.65	$6.02	$19.65	320	280	600	$5.45	$18.11

1992 TO 2021 FPL SHORT TERM/ DRI 4Q91 BASE CASE LONG TERM FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLAR PRICES

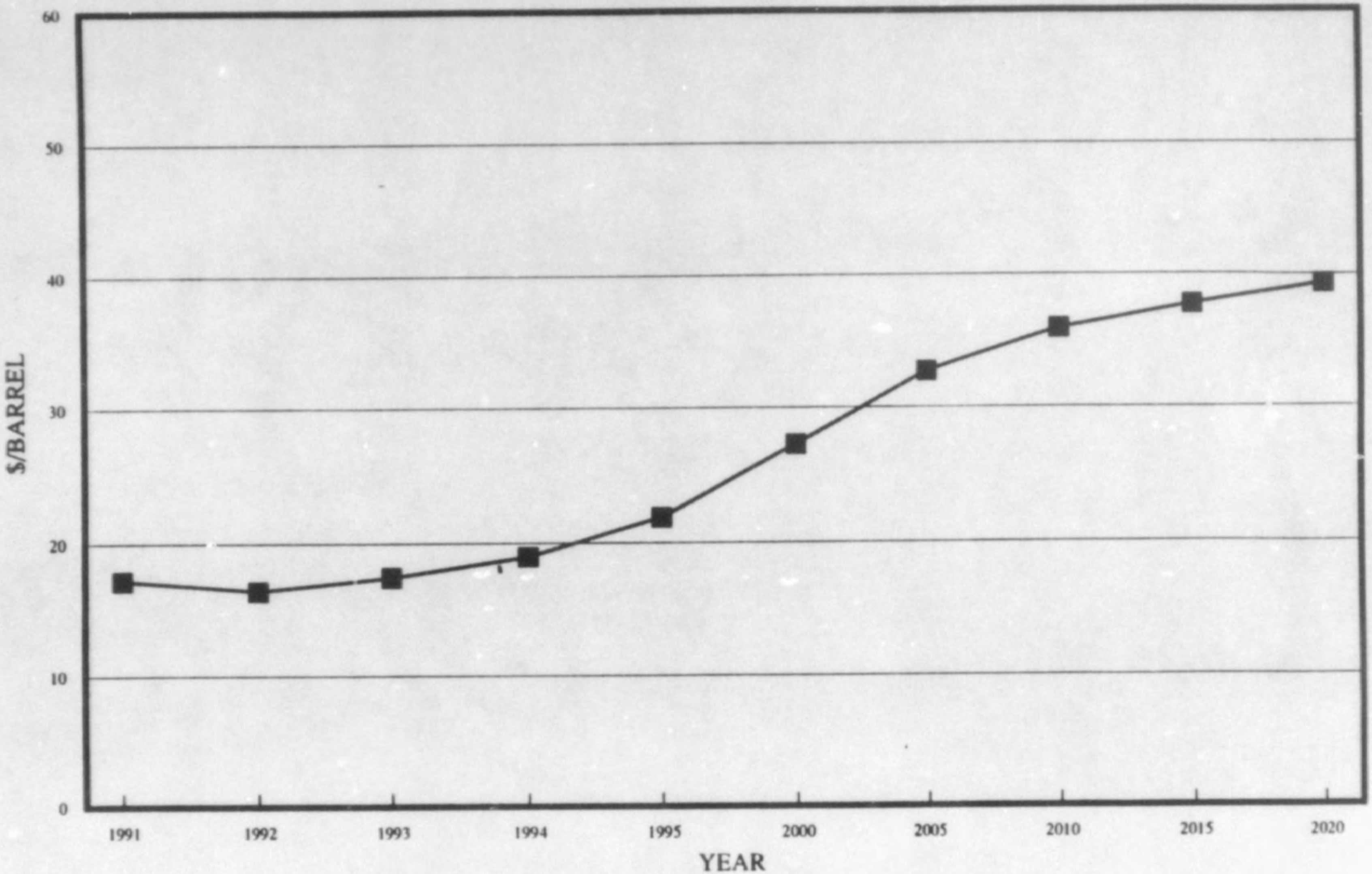
D E L I V E R E D   N O M I N A L   D O L L A R   C O A L   P R I C E S   I N   D O L L A R S   P E R   T O N   &   P E R   M M B T U

FEBRUARY 4, 1992

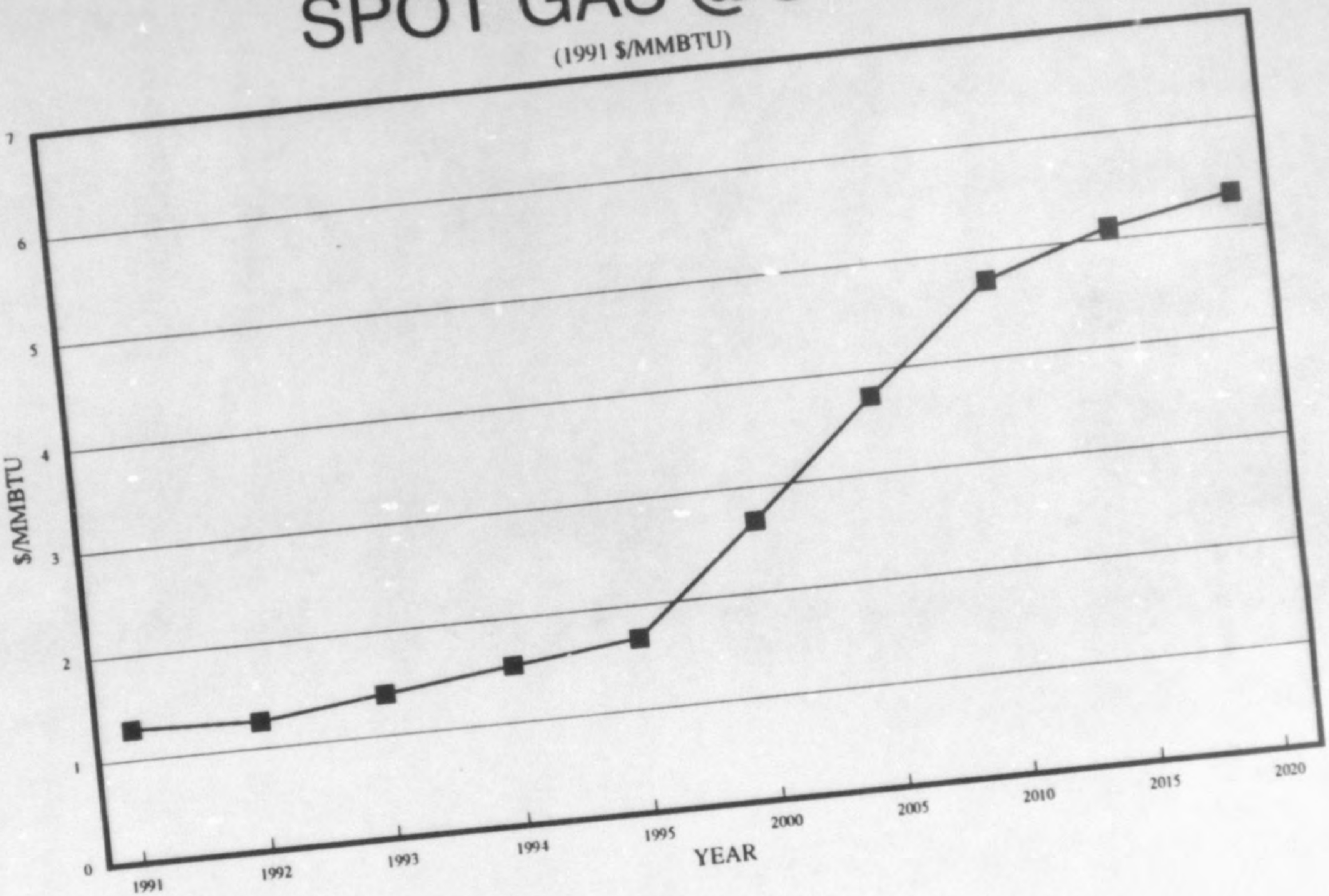
	ST. JOHNS RIVER POWER PARK COAL WEIGHTED AVERAGE NOMINAL		ST. JOHNS RIVER POWER PARK COAL SPOT PRICE NOMINAL		SCHERER UNIT 4 EASTERN COMPLIANCE COAL NOMINAL		MARTIN PLANT SITE HIGH SULFUR COAL NOMINAL		MARTIN PLANT SITE LOW SULFUR COAL NOMINAL	
YEAR	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1992	$43.73	$1.78	$38.34	$1.60	$50.59	$2.04	$44.96	$1.87	$42.87	$1.79
1993	$41.88	$1.71	$39.58	$1.65	$54.37	$2.23	$46.57	$1.94	$44.68	$1.86
1994	$43.16	$1.76	$41.79	$1.72	$55.26	$2.25	$48.43	$2.02	$46.68	$1.94
1995	$44.45	$1.82	$43.51	$1.81	$50.86	$2.10	$50.51	$2.10	$48.89	$2.04
1996	$45.48	$1.86	$45.44	$1.89	$51.94	$2.16	$52.08	$2.17	$50.52	$2.11
1997	$48.01	$1.96	$47.38	$1.97	$54.10	$2.32	$53.77	$2.24	$52.27	$2.18
1998	$50.32	$2.05	$49.71	$2.07	$56.95	$2.45	$55.57	$2.32	$54.12	$2.25
1999	$51.59	$2.10	$52.07	$2.17	$60.38	$2.61	$57.47	$2.39	$56.03	$2.33
2000	$54.39	$2.22	$54.60	$2.28	$63.53	$2.75	$60.62	$2.53	$60.71	$2.53
2001	$56.44	$2.30	$57.33	$2.39	$66.58	$2.88	$62.97	$2.62	$63.11	$2.63
2002	$58.24	$2.42	$60.21	$2.51	$69.65	$3.01	$65.42	$2.73	$65.60	$2.73
2003	$60.88	$2.54	$63.18	$2.63	$72.90	$3.15	$67.97	$2.83	$68.19	$2.84
2004	$63.32	$2.64	$66.29	$2.76	$76.24	$3.30	$70.63	$2.94	$70.91	$2.95
2005	$68.75	$2.86	$69.56	$2.90	$79.74	$3.45	$75.69	$3.15	$76.69	$3.20
2006	$71.45	$2.98	$72.84	$3.03	$83.50	$3.61	$78.66	$3.28	$79.69	$3.32
2007	$74.37	$3.10	$76.46	$3.19	$87.60	$3.79	$81.82	$3.41	$82.93	$3.46
2008	$77.45	$3.23	$80.31	$3.35	$91.73	$3.97	$85.13	$3.55	$86.34	$3.60
2009	$80.71	$3.36	$84.32	$3.51	$95.79	$4.17	$88.64	$3.6[illegible]	$89.96	$3.75
2010	$87.36	$3.64	$88.52	$3.69	$100.63	$4.38	$95.03	$3.96	$97.07	$4.04
2011	$91.00	$3.79	$92.83	$3.87	$105.65	$4.60	$98.94	$4.12	$101.10	$4.21
2012	$94.93	$3.96	$97.44	$4.06	$111.05	$4.83	$103.15	$4.30	$105.45	$4.39
2013	$99.11	$4.13	$102.27	$4.26	$116.36	$5.06	$107.64	$4.49	$110.09	$4.59
2014	$103.56	$4.32	$107.30	$4.47	$121.94	$5.31	$112.42	$4.68	$115.02	$4.79
2015	$111.09	$4.63	$112.51	$4.69	$127.80	$5.56	$119.47	$4.98	$123.12	$5.13
2016	$116.03	$4.83	$117.89	$4.91	$133.85	$5.83	$124.72	$5.20	$128.58	$5.36
2017	$121.22	$5.05	$123.58	$5.15	$140.32	$6.11	$130.24	$5.43	$134.32	$5.60
2018	$126.61	$5.28	$129.36	$5.39	$147.10	$6.40	$136.01	$5.67	$140.29	$5.85
2019	$132.27	$5.51	$135.44	$5.64	$154.14	$6.71	$142.06	$5.92	$146.54	$6.11
2020	$138.19	$5.76	$141.78	$5.91	$161.39	$7.02	$148.41	$6.18	$153.09	$6.38
2021	$144.39	$6.02	$148.44	$6.19	$169.01	$7.36	$155.07	$6.46	$159.95	$6.66

INTERNATIONALLY TRADED CRUDE OIL

(1991 $/BARREL)

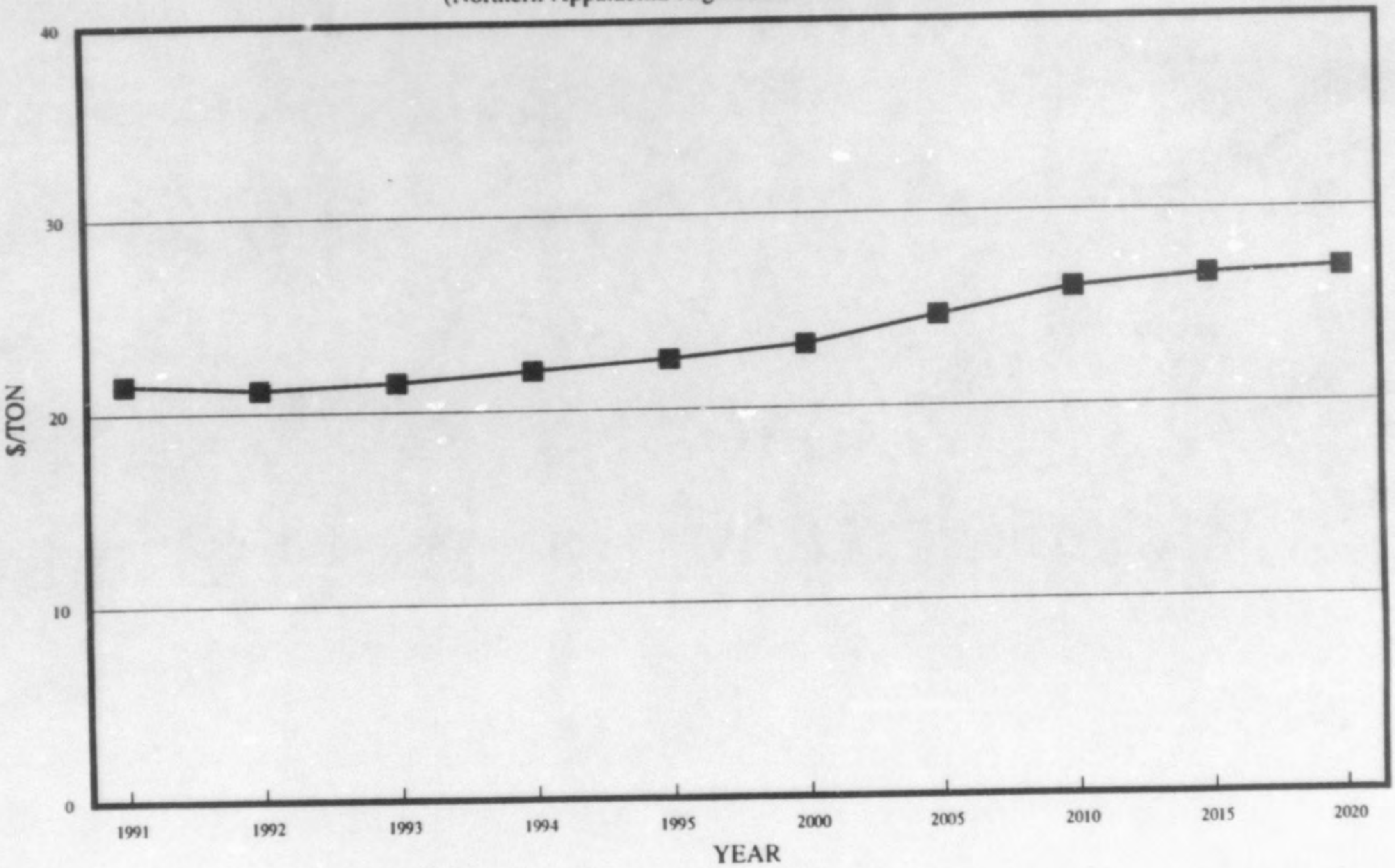


SPOT GAS @USGC

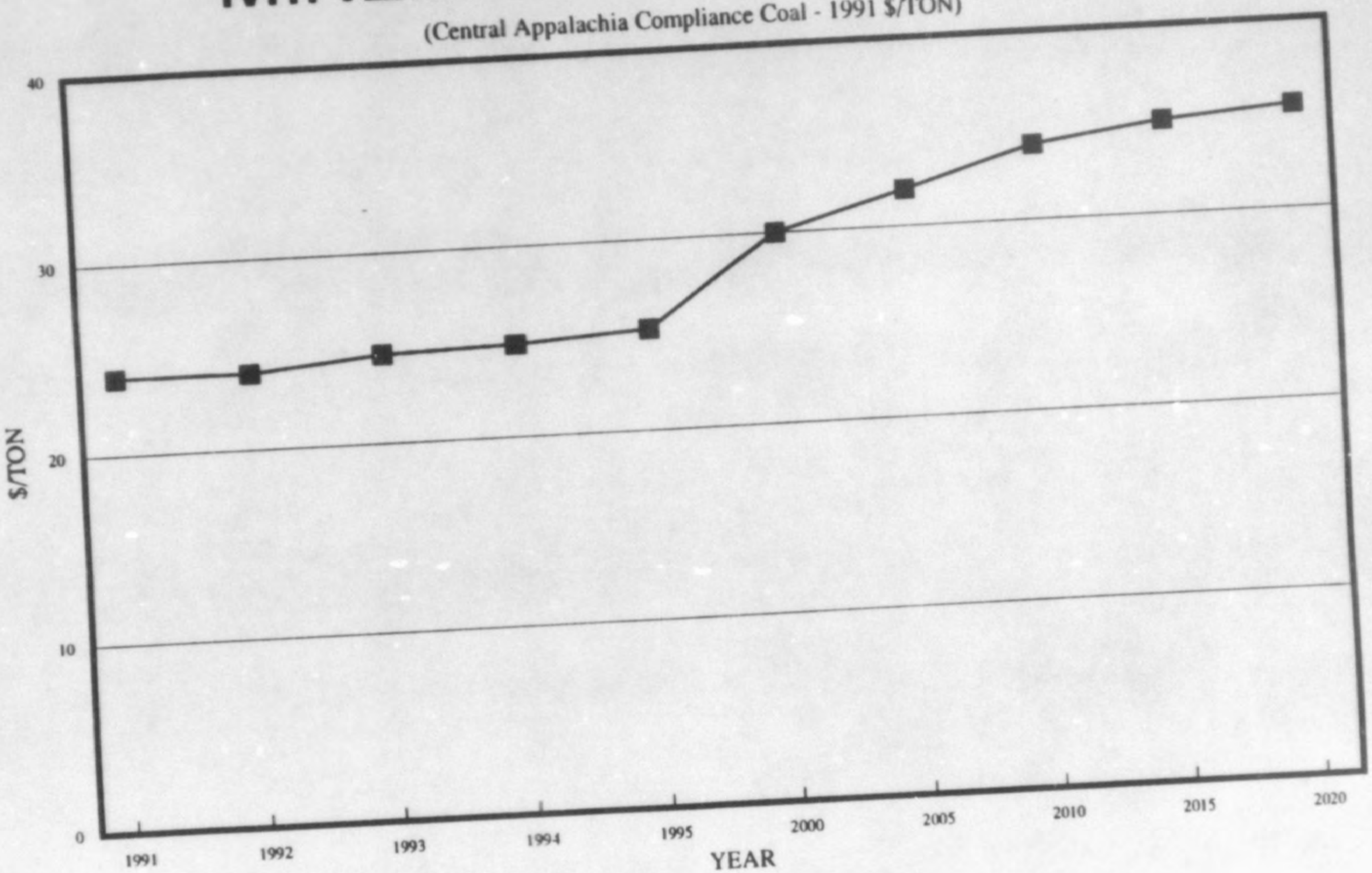


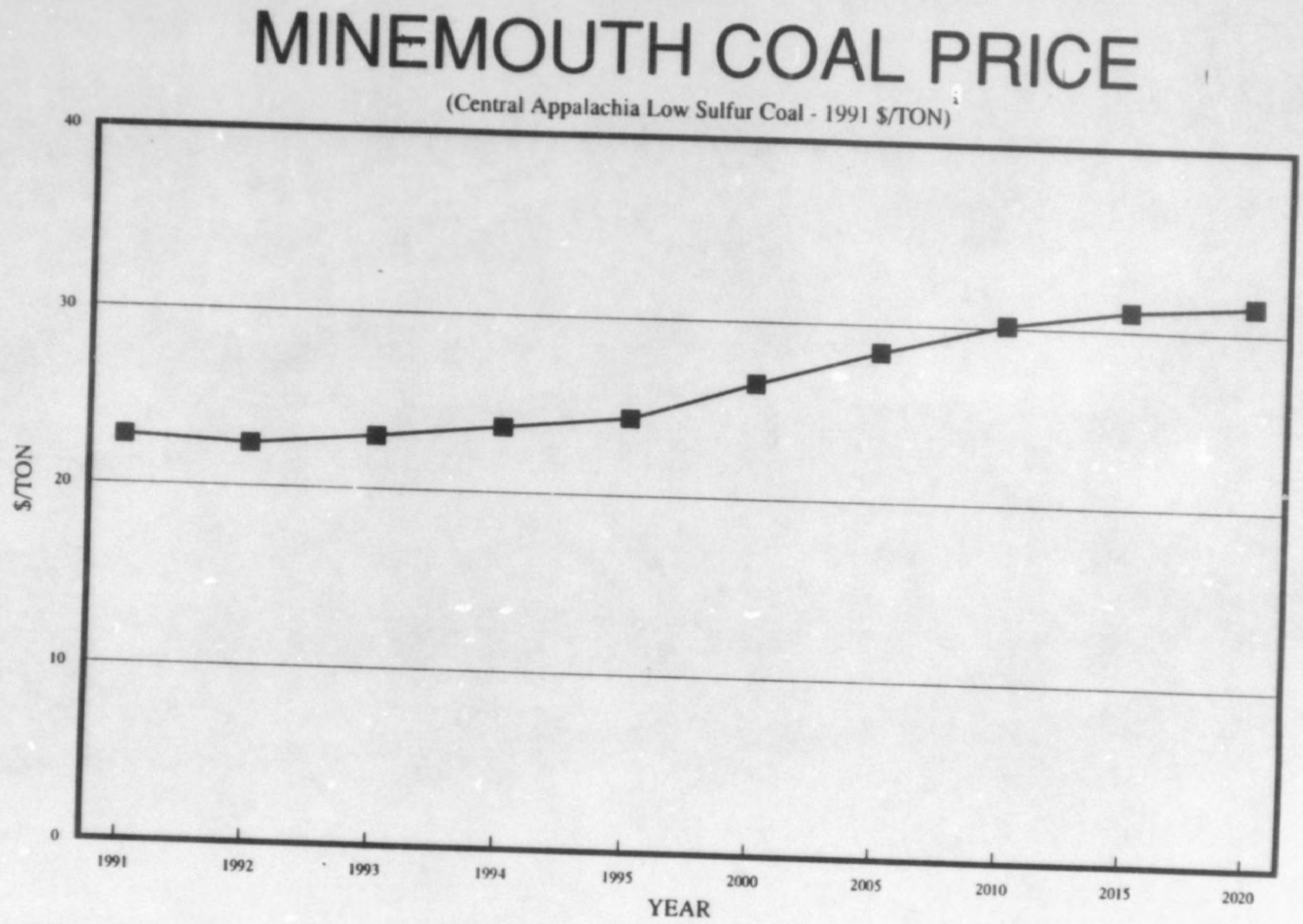
MINEMOUTH COAL PRICE

(Northern Appalachia High Sulfur Coal - 1991 $/TON)



MINEMOUTH COAL PRICE




MINEMOUTH COAL PRICE
(Central Appalachia Low Sulfur Coal - 1991 $/TON)
40
30
20
10
0
$/TON
1991
1992
1993
1994
1995
2000
2005
2010
2015
2020
YEAR

Inter-Office Correspondence

FPL

To: Distribution

Date: March 3, 1993

From: A. J. Olivera
C. O. Woody

Department: Executive

Subject: **FPL Short-Term/Data Resources, Inc. (DRI) Long-Term Base Case Fossil Fuel Price and Natural Gas Availability Forecast**

Attached is the current annual Short and Long-Term Base Case Fossil Fuel Price Forecast for crude oil, residual and distillate fuel oil, natural gas, coal and Orimulsion, as well as the current projection for natural gas availability. This forecast represents the combination of the current October 8, 1992 monthly FPL Short-Term Fossil Fuel Price Forecast through 1996, and the DRI August, 1992 annual Long-Term Forecast for 1997 and beyond. For planning purposes, this forecast supersedes the February 20, 1992 annual FPL Short-Term/DRI Long-Term Base Case Fossil Fuel Price and Natural Gas Availability Forecast.

The most significant changes in assumptions and forecast results between the current forecast and last year's forecast are:

- A 15% decline by 2020 in the 1% sulfur residual fuel oil price (1992 $) due primarily to: 1) greater optimism concerning cost of crude oil production; and 2) improved foreign investment climate for exploration and development.

- A 30% decline by 2020 in the natural gas price (1992 $) due primarily to: 1) greater optimism concerning domestic exploration and development technological improvements; and 2) competition from lower priced residual fuel oil and coal.

- A 14% decline by 2020 in the high sulfur coal price (1992 $) to the Martin site due primarily to: 1) significant improvement in coal mining productivity growth; and 2) the assumed change in high sulfur coal origin (Western Kentucky rather than Northern West Virginia).

- A 53% decline by 2020 in the compliance coal price (1992 $) to Plant Scherer due primarily to the assumed change in compliance coal origin (Wyoming Powder River Basin rather than Central Appalachian Compliance Coal).

If you have any questions concerning the underlying assumptions supporting the current Long-Term Fossil Fuel Price and Natural Gas Availability Forecast, or the resulting forecast values, please contact Eugene Ungar at 552-3412 or John Wehner at 694-3411. A comparison of the major assumptions supporting the current Long-Term Fuel Price Forecast with the February 20, 1992 forecast is available upon request.

A. J. Olivera
Vice President,
Planning & Resource Allocation

C. O. Woody
Senior Vice President,
Power Generation

Attachments
/cd

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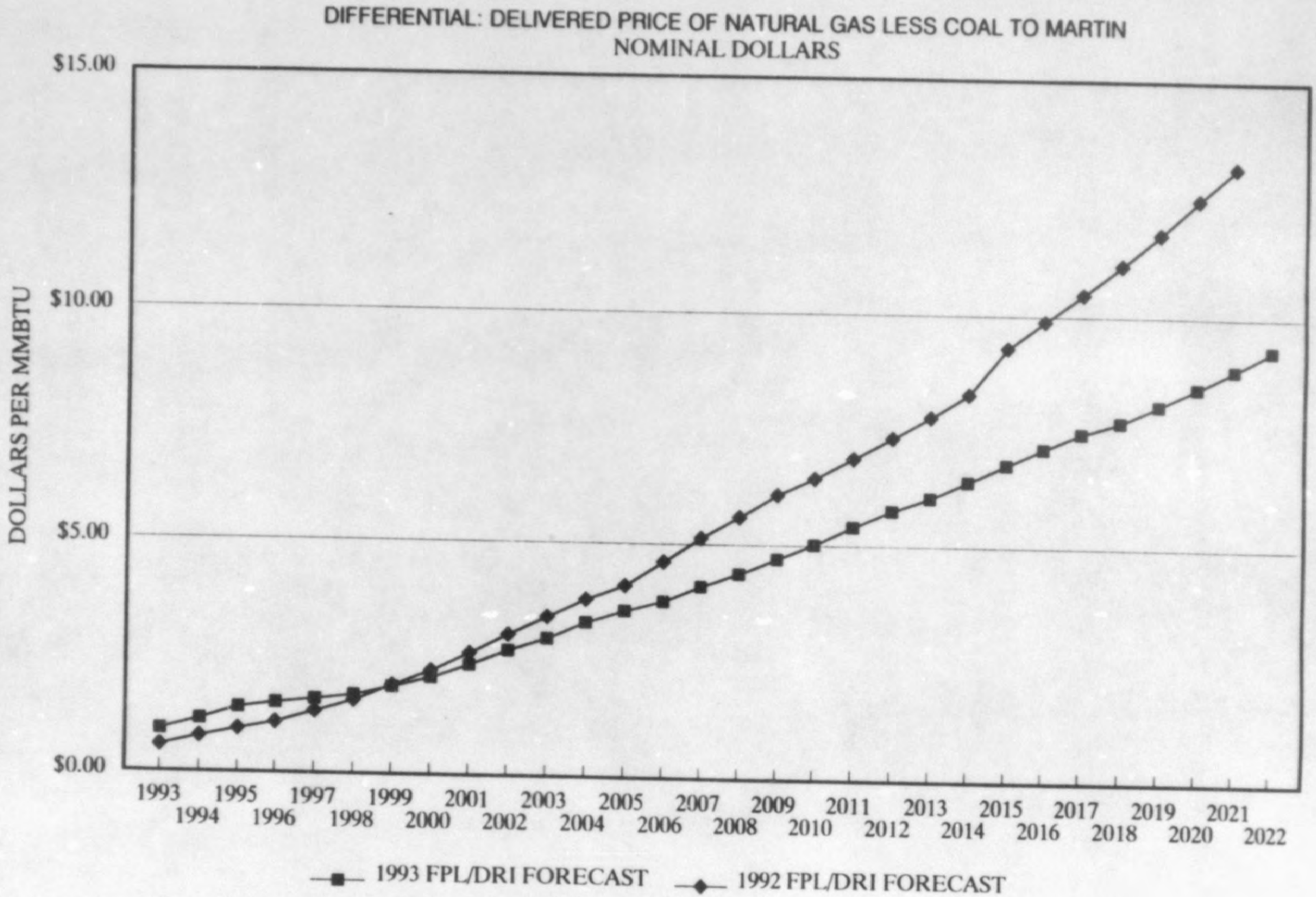
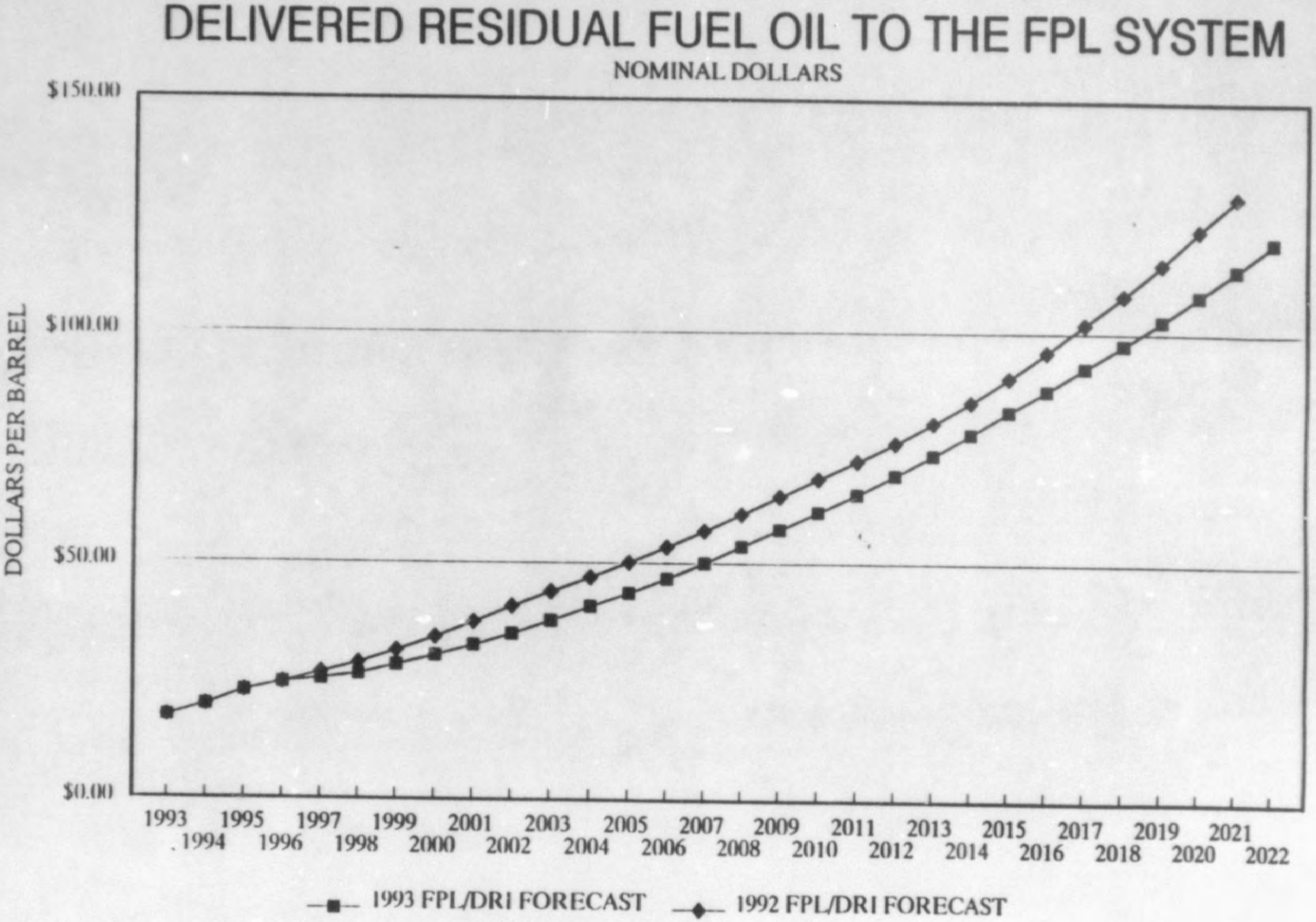
1993 TO 2022 FPL SHORT-TERM/DRI LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

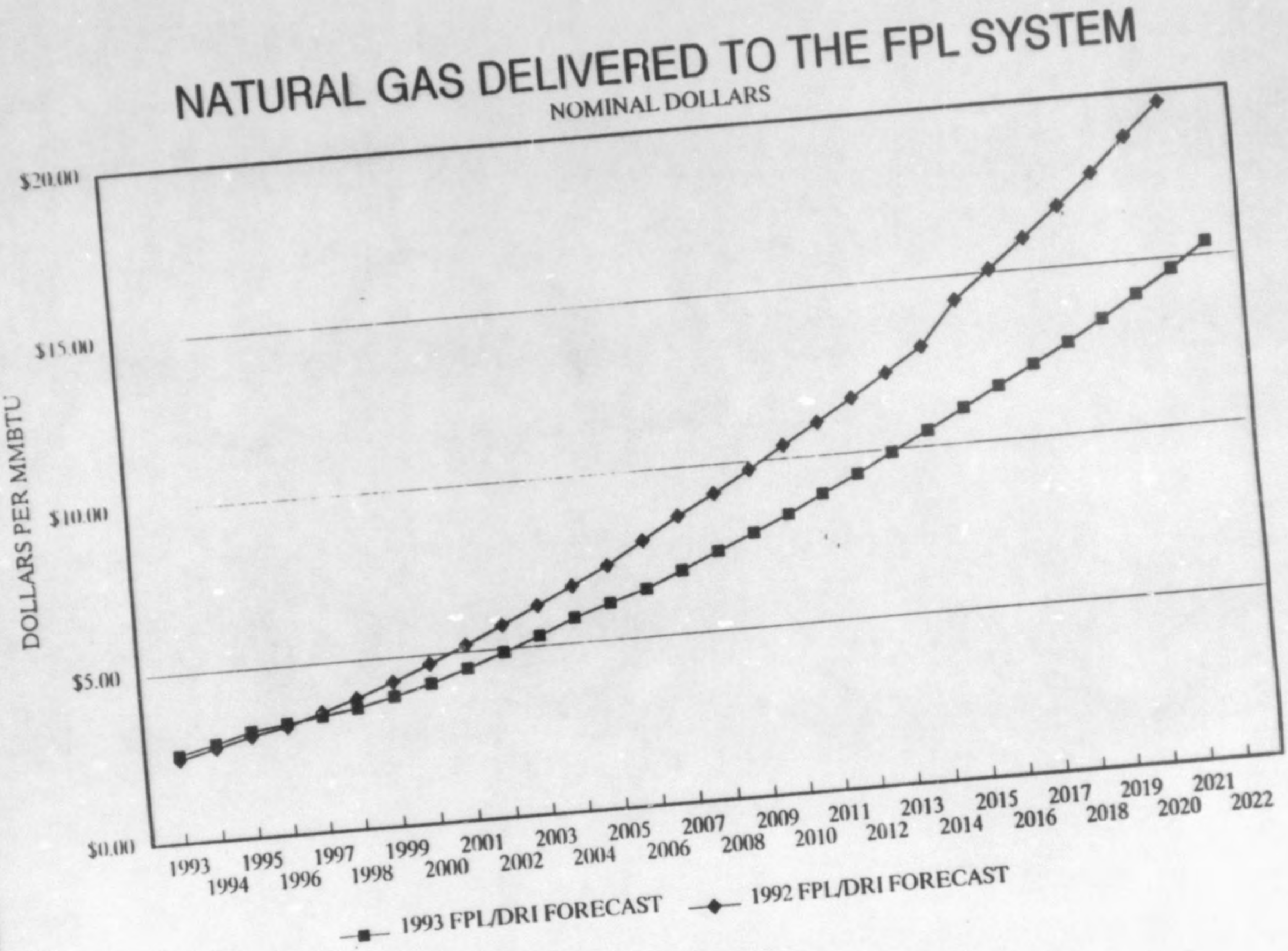
DELIVERED NOMINAL DOLLAR COAL & ORIMULSION PRICES IN DOLLARS PER TON & PER MMBTU
FPL SHORT - TERM/DRI AUGUST, 1992 LONG - TERM BASE CASE FORECAST

MARCH 1993

	ST. JOHNS RIVER POWER PARK COAL				ORIMULSION ASSUMING A 1998 PLANT STARTUP			
	WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		CONTRACT PRICE NOMINAL		SPOT PRICE NOMINAL	
YEAR	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1993	$38.34	$1.56	$31.12	$1.26	$40.08	$1.57	$31.99	$1.26
1994	$38.63	$1.57	$31.47	$1.26	$40.91	$1.61	$32.10	$1.26
1995	$39.37	$1.60	$32.61	$1.31	$42.02	$1.65	$33.29	$1.31
1996	$40.48	$1.65	$34.27	$1.39	$42.97	$1.69	$35.42	$1.39
1997	$37.76	$1.56	$35.75	$1.51	$42.25	$1.66	$38.59	$1.51
1998	$38.86	$1.62	$36.54	$1.59	$43.56	$1.71	$40.47	$1.59
1999	$39.80	$1.66	$36.68	$1.59	$45.17	$1.77	$40.63	$1.59
2000	$40.37	$1.69	$37.39	$1.63	$45.85	$1.80	$41.42	$1.63
2001	$41.71	$1.74	$38.11	$1.66	$47.60	$1.87	$42.22	$1.66
2002	$41.69	$1.79	$40.86	$1.78	$48.04	$1.89	$45.27	$1.78
2003	$41.57	$1.81	$42.78	$1.86	$47.75	$1.87	$47.39	$1.86
2004	$43.21	$1.88	$44.77	$1.95	$47.13	$1.85	$49.60	$1.95
2005	$46.49	$2.02	$46.91	$2.04	$51.30	$2.01	$51.97	$2.04
2006	$48.49	$2.11	$49.26	$2.14	$53.35	$2.09	$54.57	$2.14
2007	$50.60	$2.20	$51.73	$2.25	$55.52	$2.18	$57.31	$2.25
2008	$53.88	$2.30	$57.69	$2.36	$57.89	$2.27	$60.24	$2.36
2009	$56.27	$2.40	$60.36	$2.47	$60.40	$2.37	$63.03	$2.47
2010	$63.19	$2.70	$63.26	$2.59	$69.97	$2.75	$66.06	$2.59
2011	$66.14	$2.83	$66.47	$2.72	$73.11	$2.87	$69.41	$2.72
2012	$69.35	$2.96	$70.12	$2.87	$76.46	$3.00	$73.22	$2.87
2013	$72.82	$3.11	$74.25	$3.04	$80.00	$3.14	$77.54	$3.04
2014	$75.15	$3.27	$74.23	$3.23	$83.69	$3.28	$82.23	$3.23
2015	$77.49	$3.37	$78.20	$3.40	$85.51	$3.36	$86.64	$3.40
2016	$81.23	$3.53	$82.41	$3.58	$89.42	$3.51	$91.30	$3.58
2017	$85.19	$3.70	$86.90	$3.78	$93.56	$3.67	$96.27	$3.78
2018	$89.33	$3.88	$91.61	$3.98	$97.88	$3.84	$101.49	$3.98
2019	$93.70	$4.07	$96.59	$4.20	$102.43	$4.02	$107.01	$4.20
2020	$100.98	$4.39	$101.90	$4.43	$111.43	$4.37	$112.89	$4.43
2021	$105.87	$4.60	$107.43	$4.67	$116.55	$4.57	$119.02	$4.67
2022	$111.03	$4.83	$113.30	$4.93	$121.93	$4.79	$125.51	$4.93


DIFFERENTIAL: DELIVERED PRICE OF NATURAL GAS LESS COAL TO MARTIN
NOMINAL DOLLARS
DOLLARS PER MMBTU
$15.00
$10.00
$5.00
$0.00
1993
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
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST


DELIVERED RESIDUAL FUEL OIL TO THE FPL SYSTEM
NOMINAL DOLLARS
DOLLARS PER BARREL
$150.00
$100.00
$50.00
$0.00
1993
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
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST


NATURAL GAS DELIVERED TO THE FPL SYSTEM
NOMINAL DOLLARS
DOLLARS PER MMBTU
$20.00
$15.00
$10.00
$5.00
$0.00
1993
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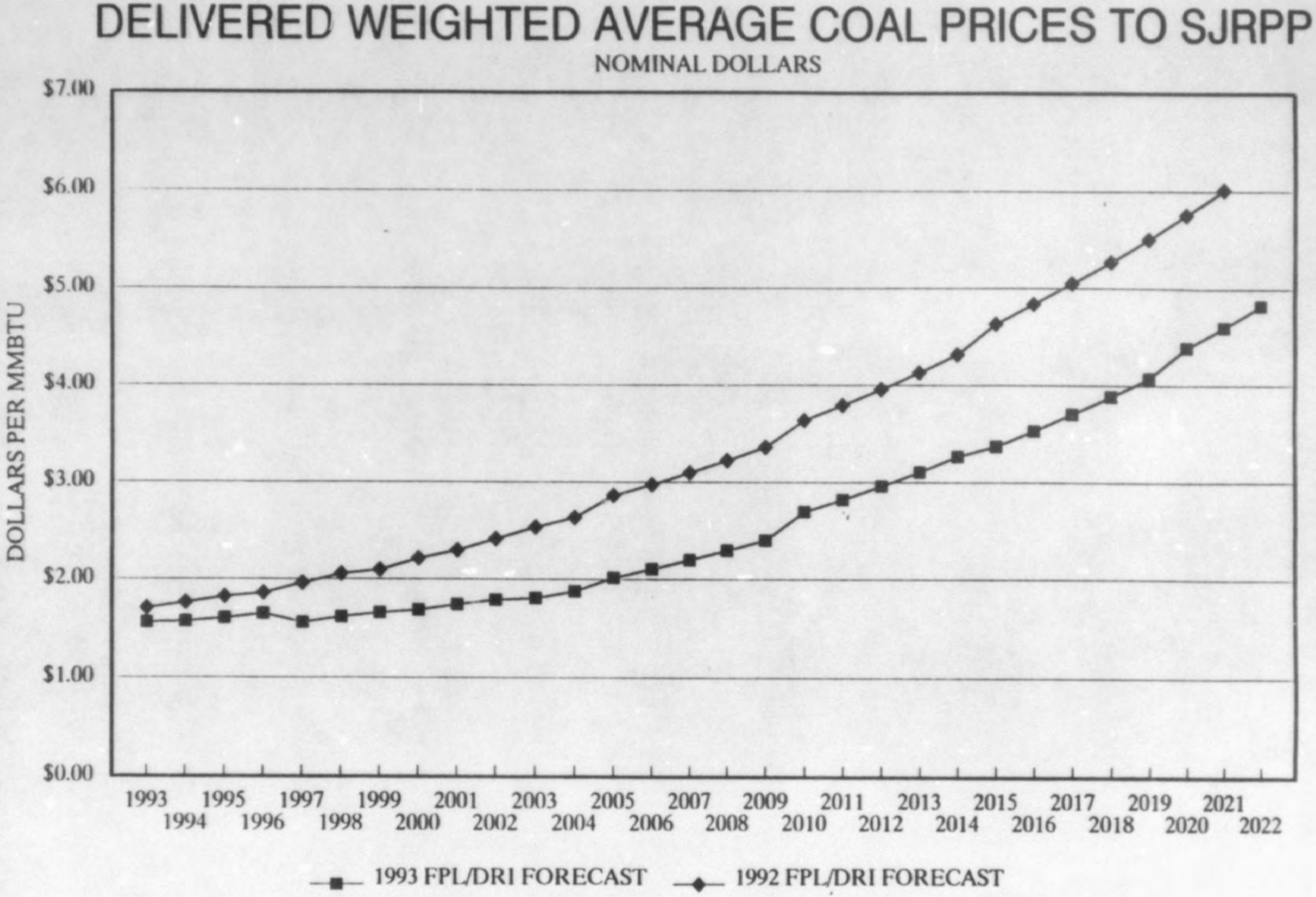
2021
2022
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST


DELIVERED WEIGHTED AVERAGE COAL PRICES TO SJRPP
NOMINAL DOLLARS
DOLLARS PER MMBTU
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1993
1994
1995
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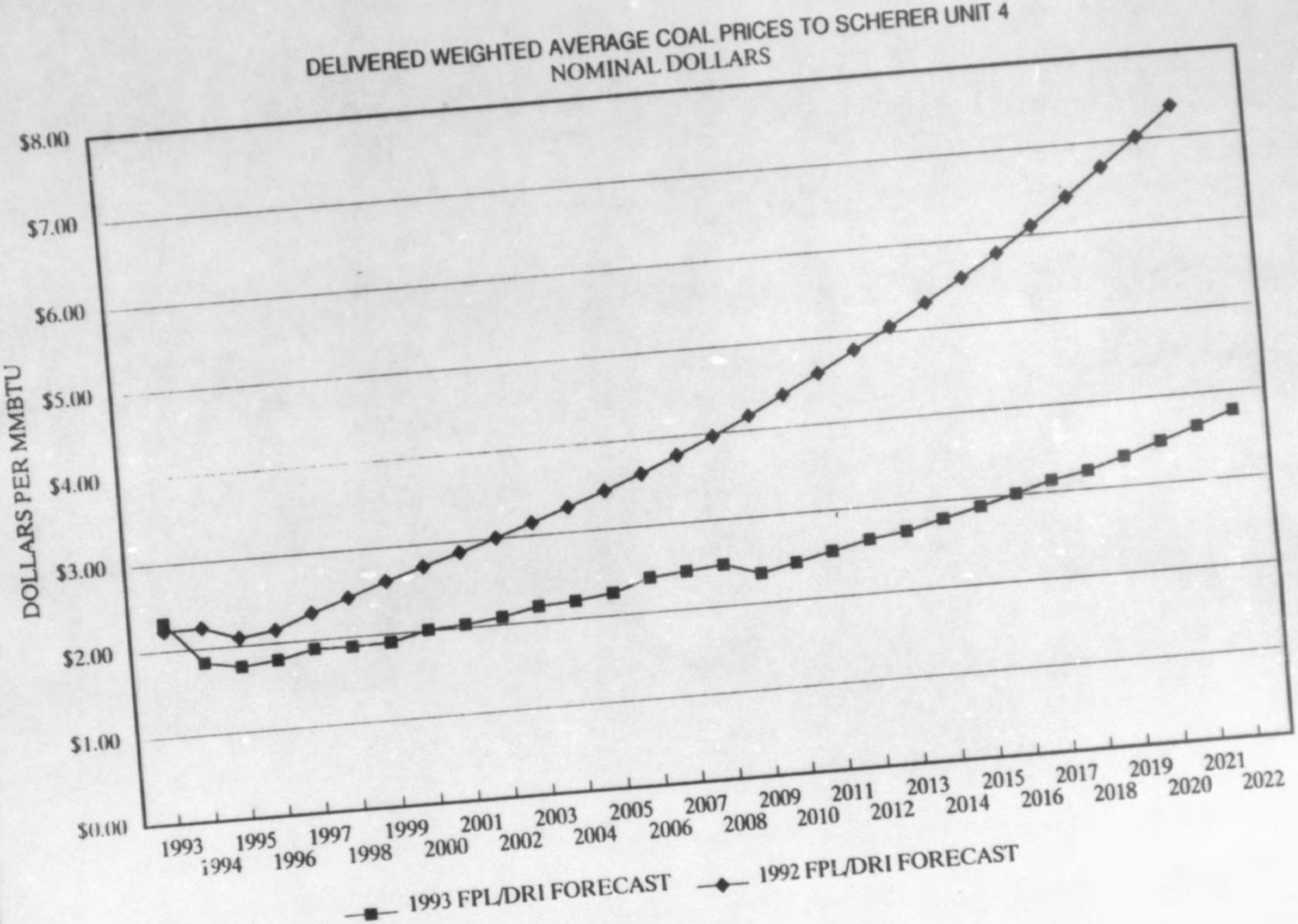
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST


DELIVERED WEIGHTED AVERAGE COAL PRICES TO SCHERER UNIT 4
NOMINAL DOLLARS
DOLLARS PER MMBTU
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1993
1994
1995
1996
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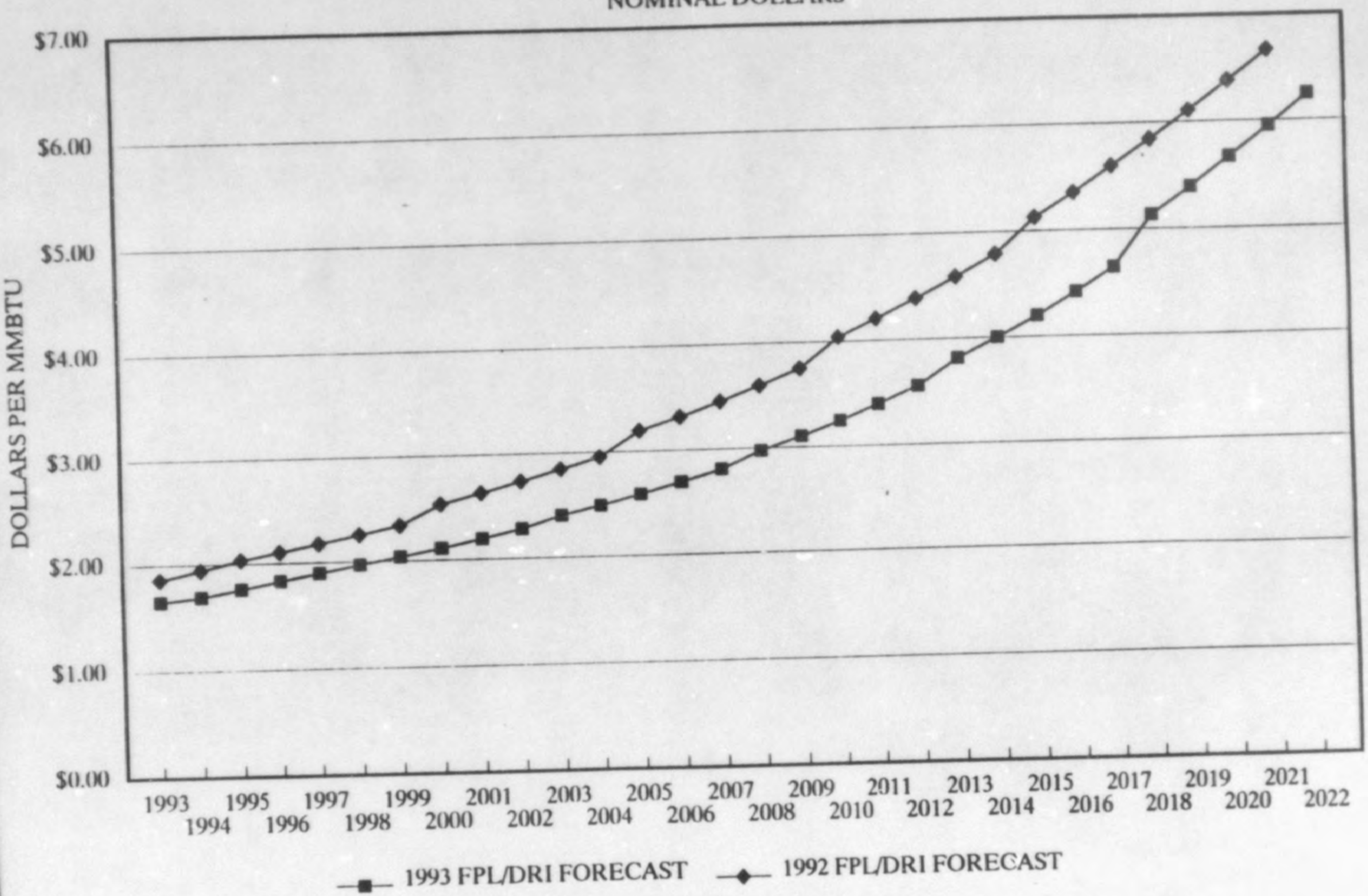
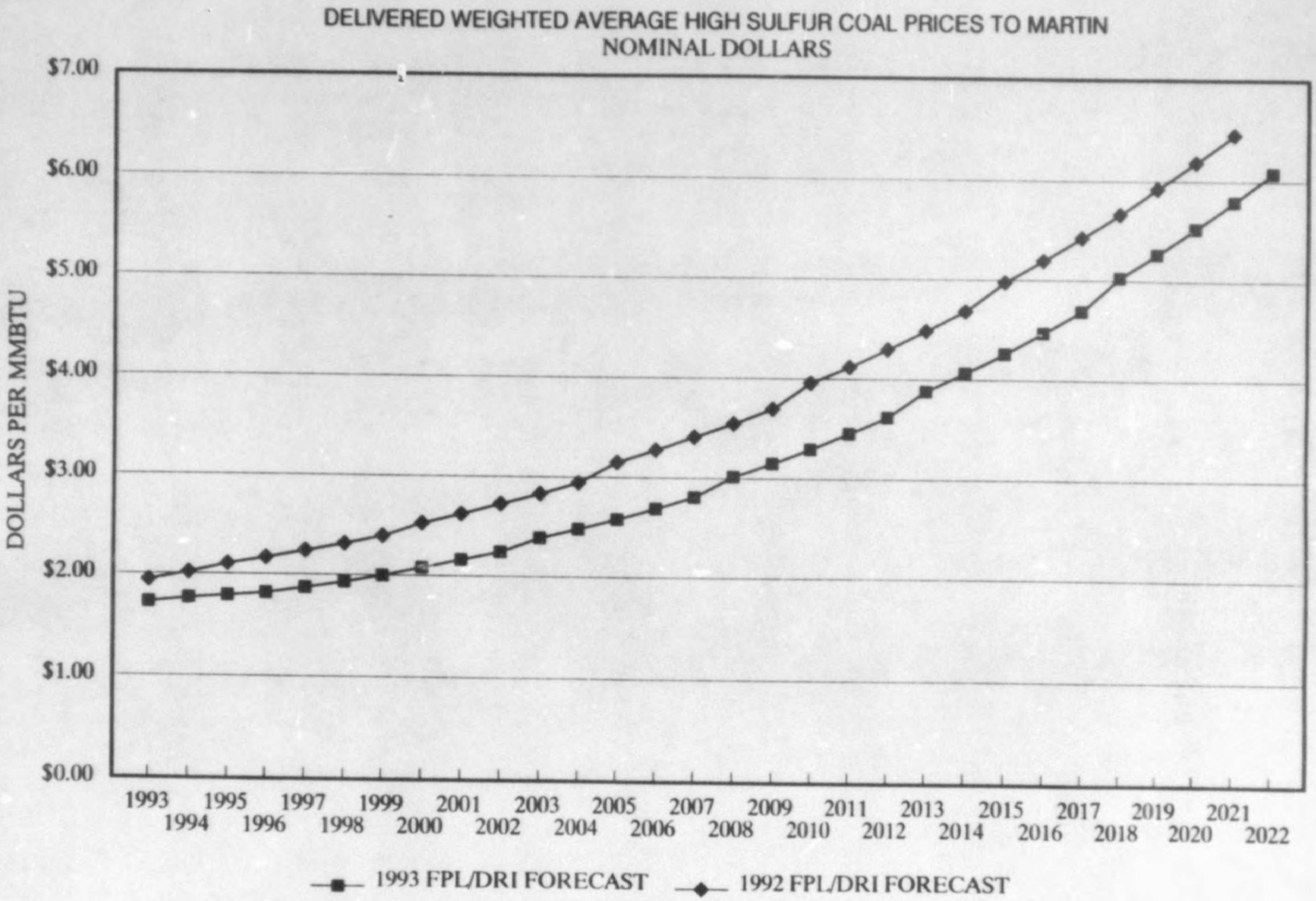
2021
2022
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST

DELIVERED WEIGHTED AVERAGE LOW SULFUR COAL PRICES TO MARTIN
NOMINAL DOLLARS




DELIVERED WEIGHTED AVERAGE HIGH SULFUR COAL PRICES TO MARTIN
NOMINAL DOLLARS
DOLLARS PER MMBTU
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1993
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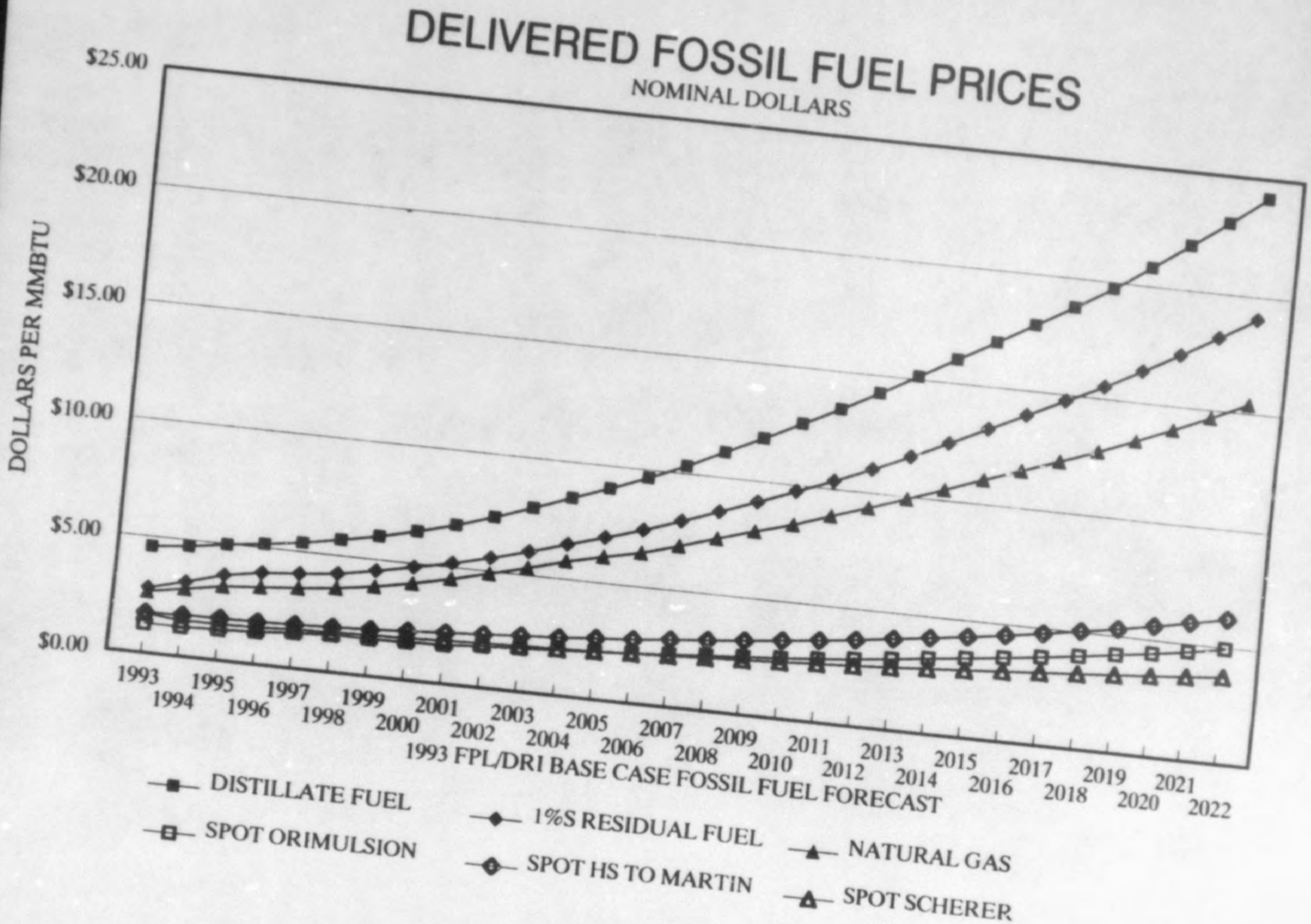
2022
1993 FPL/DRI FORECAST
1992 FPL/DRI FORECAST


DELIVERED FOSSIL FUEL PRICES
NOMINAL DOLLARS
DOLLARS PER MMBTU
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
1993
1994
1995
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2021
2022
1993 FPL/DRI BASE CASE FOSSIL FUEL FORECAST
DISTILLATE FUEL
1%S RESIDUAL FUEL
NATURAL GAS
SPOT ORIMULSION
SPOT HS TO MARTIN
SPOT SCHERER

1993 TO 2022 FPL SHORT-TERM/DRI LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

CONSTANT 1992 DOLLAR & NOMINAL DOLLAR CRUDE OIL & FUEL OIL PRICES

FPL SHORT-TERM/DRI AUGUST, 1992 LONG-TERM BASE CASE FORECAST

MARCH 1993

YEAR	CRUDE OIL PRICE: ARABIAN LIGHT $/BBL		ARABIAN LIGHT $/MMBTU		WEST TEXAS INTERMEDIATE $/BBL		WEST TEXAS INTERMEDIATE $/MMBTU		1.0% S RESIDUAL FUEL OIL @ US GULF COAST "PLATT'S" LOW POSTING @ US GULF COAST $/BBL		$/MMBTU	
	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL
1993	$17.86	$18.33	$3.08	$3.16	$20.78	$21.33	$3.58	$3.68	$15.89	$16.31	$2.53	$2.59
1994	$19.37	$20.48	$3.34	$3.53	$22.21	$23.48	$3.83	$4.05	$17.77	$18.79	$2.83	$2.99
1995	$21.18	$23.06	$3.65	$3.98	$23.94	$26.06	$4.13	$4.49	$20.00	$21.77	$3.18	$3.46
1996	$21.33	$23.85	$3.68	$4.11	$24.21	$27.08	$4.17	$4.67	$20.95	$23.43	$3.33	$3.73
1997	$21.48	$24.75	$3.70	$4.27	$24.48	$28.21	$4.22	$4.86	$21.05	$24.26	$3.35	$3.86
1998	$21.62	$25.81	$3.73	$4.45	$24.76	$29.56	$4.27	$5.10	$21.15	$25.25	$3.36	$4.02
1999	$22.17	$27.49	$3.82	$4.74	$25.41	$31.51	$4.38	$5.43	$21.85	$27.10	$3.48	$4.31
2000	$22.72	$29.34	$3.92	$5.06	$26.07	$33.67	$4.49	$5.80	$22.43	$28.97	$3.57	$4.61
2001	$23.40	$31.48	$4.03	$5.43	$26.86	$36.13	$4.63	$6.23	$23.14	$31.13	$3.68	$4.95
2002	$24.17	$33.83	$4.17	$5.83	$27.77	$38.87	$4.79	$6.70	$23.96	$33.54	$3.81	$5.33
2003	$25.04	$36.46	$4.32	$6.29	$28.77	$41.89	$4.96	$7.22	$24.86	$36.20	$3.95	$5.76
2004	$25.97	$39.34	$4.48	$6.78	$29.85	$45.22	$5.15	$7.80	$25.84	$39.15	$4.11	$6.23
2005	$26.65	$42.07	$4.59	$7.25	$30.65	$48.39	$5.28	$8.34	$26.57	$41.94	$4.23	$6.67
2006	$27.28	$44.98	$4.70	$7.76	$31.39	$51.76	$5.41	$8.92	$27.25	$44.94	$4.33	$7.15
2007	$27.95	$48.17	$4.82	$8.31	$32.18	$55.46	$5.55	$9.56	$27.98	$48.22	$4.45	$7.67
2008	$28.57	$51.56	$4.93	$8.89	$32.90	$59.37	$5.67	$10.24	$28.65	$51.70	$4.56	$8.22
2009	$29.10	$55.02	$5.02	$9.49	$33.54	$63.42	$5.78	$10.93	$29.24	$55.28	$4.65	$8.79
2010	$29.58	$58.67	$5.10	$10.12	$34.11	$67.66	$5.88	$11.66	$29.78	$59.07	$4.74	$9.40
2011	$29.98	$62.42	$5.17	$10.76	$34.57	$71.97	$5.96	$12.41	$30.16	$62.79	$4.80	$9.99
2012	$30.34	$66.36	$5.23	$11.44	$34.98	$76.50	$6.03	$13.19	$30.54	$66.79	$4.86	$10.62
2013	$30.65	$70.43	$5.28	$12.14	$35.34	$81.21	$6.09	$14.00	$30.92	$71.05	$4.92	$11.30
2014	$30.92	$74.64	$5.33	$12.87	$35.65	$86.06	$6.15	$14.84	$31.29	$75.53	$4.98	$12.01
2015	$31.10	$78.83	$5.36	$13.59	$35.86	$90.90	$6.18	$15.67	$31.67	$80.28	$5.04	$12.77
2016	$31.26	$83.22	$5.39	$14.35	$35.95	$95.71	$6.20	$16.50	$31.84	$84.77	$5.06	$13.48
2017	$31.44	$87.94	$5.42	$15.16	$36.03	$100.78	$6.21	$17.38	$32.04	$89.62	$5.10	$14.26
2018	$31.49	$92.51	$5.43	$15.95	$36.09	$106.03	$6.22	$18.28	$32.12	$94.37	$5.11	$15.01
2019	$31.58	$97.46	$5.44	$16.80	$36.19	$111.69	$6.24	$19.26	$32.22	$99.43	$5.12	$15.82
2020	$31.65	$102.63	$5.46	$17.69	$36.27	$117.61	$6.25	$20.28	$32.31	$104.77	$5.14	$16.66
2021	$31.67	$107.86	$5.46	$18.60	$36.30	$123.62	$6.26	$21.31	$32.35	$110.17	$5.15	$17.52
2022	$31.69	$113.35	$5.46	$19.54	$36.32	$129.91	$6.26	$22.40	$32.38	$115.32	$5.15	$18.42

1993 TO 2022 FPL SHORT–TERM/DRI LONG–TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED CONSTANT 1992 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES IN DOLLARS PER BARREL & PER MMBTU
FPL SHORT – TERM/DRI AUGUST, 1992 LONG – TERM BASE CASE FORECAST

MARCH 1993

YEAR	***********0.3%SULFUR FUEL OIL**********			
	----$/BBL----		---$/MMBTU---	
	1992$	NOMINAL	1992$	NOMINAL
1993	$19.64	$20.13	$3.12	$3.20
1994	$21.59	$22.76	$3.43	$3.62
1995	$22.10	$23.96	$3.51	$3.81
1996	$23.14	$25.75	$3.68	$4.10
1997	$23.31	$26.73	$3.71	$4.25
1998	$23.48	$27.89	$3.73	$4.44
1999	$24.33	$30.03	$3.87	$4.78
2000	$25.06	$32.21	$3.99	$5.12
2001	$25.77	$34.51	$4.10	$5.49
2002	$26.59	$37.06	$4.23	$5.89
2003	$27.49	$39.86	$4.37	$6.34
2004	$28.47	$42.96	$4.53	$6.83
2005	$29.20	$45.92	$4.64	$7.30
2006	$29.88	$49.08	$4.75	$7.81
2007	$30.60	$52.54	$4.87	$8.36
2008	$31.28	$56.24	$4.97	$8.95
2009	$31.87	$60.04	$5.07	$9.55
2010	$32.41	$64.06	$5.15	$10.19
2011	$32.79	$68.03	$5.21	$10.82
2012	$33.17	$72.29	$5.28	$11.50
2013	$33.54	$76.81	$5.33	$12.22
2014	$33.92	$81.60	$5.39	$12.98
2015	$34.30	$86.65	$5.45	$13.78
2016	$34.47	$91.46	$5.48	$14.55
2017	$34.67	$96.66	$5.51	$15.37
2018	$34.74	$101.73	$5.52	$16.18
2019	$34.84	$107.17	$5.54	$17.05
2020	$34.94	$112.92	$5.56	$17.96
2021	$34.98	$118.74	$5.56	$18.89
2022	$35.01	$124.82	$5.57	$19.85

YEAR	***********0.7%SULFUR FUEL OIL**********			
	----$/BBL----		---$/MMBTU---	
	1992$	NOMINAL	1992$	NOMINAL
1993	$18.93	$19.40	$3.01	$3.09
1994	$21.17	$22.31	$3.37	$3.55
1995	$21.72	$23.55	$3.45	$3.75
1996	$22.67	$25.23	$3.61	$4.01
1997	$22.77	$26.11	$3.62	$4.15
1998	$22.85	$27.14	$3.63	$4.32
1999	$23.61	$29.14	$3.75	$4.63
2000	$24.26	$31.18	$3.86	$4.96
2001	$24.97	$33.44	$3.97	$5.32
2002	$25.78	$35.93	$4.10	$5.71
2003	$26.68	$38.68	$4.24	$6.15
2004	$27.67	$41.74	$4.40	$6.64
2005	$28.39	$44.64	$4.51	$7.10
2006	$29.07	$47.75	$4.62	$7.59
2007	$29.80	$51.16	$4.74	$8.14
2008	$30.47	$54.78	$4.85	$8.71
2009	$31.07	$58.53	$4.94	$9.31
2010	$31.61	$62.47	$5.03	$9.94
2011	$31.98	$66.34	$5.09	$10.55
2012	$32.36	$70.52	$5.15	$11.22
2013	$32.74	$74.97	$5.21	$11.93
2014	$33.12	$79.67	$5.27	$12.67
2015	$33.49	$84.60	$5.33	$13.46
2016	$33.66	$89.31	$5.35	$14.20
2017	$33.87	$94.42	$5.39	$15.02
2018	$33.94	$99.38	$5.40	$15.81
2019	$34.04	$104.70	$5.41	$16.65
2020	$34.13	$110.30	$5.43	$17.54
2021	$34.17	$115.98	$5.43	$18.45
2022	$34.20	$121.92	$5.44	$19.39

YEAR	***********1.0%SULFUR FUEL OIL**********			
	----$/BBL----		---$/MMBTU---	
	1992$	NOMINAL	1992$	NOMINAL
1993	$17.11	$17.56	$2.72	$2.79
1994	$18.99	$20.04	$3.02	$3.19
1995	$21.22	$23.03	$3.37	$3.66
1996	$22.17	$24.69	$3.53	$3.93
1997	$22.27	$25.53	$3.54	$4.06
1998	$22.37	$26.57	$3.56	$4.23
1999	$23.07	$28.47	$3.67	$4.53
2000	$23.65	$30.39	$3.76	$4.83
2001	$24.36	$32.61	$3.87	$5.19
2002	$25.18	$35.09	$4.00	$5.58
2003	$26.08	$37.81	$4.15	$6.01
2004	$27.06	$40.82	$4.30	$6.49
2005	$27.79	$43.69	$4.42	$6.95
2006	$28.47	$46.76	$4.53	$7.44
2007	$29.20	$50.13	$4.64	$7.97
2008	$29.87	$53.70	$4.75	$8.54
2009	$30.46	$57.37	$4.84	$9.13
2010	$31.00	$61.26	$4.93	$9.74
2011	$31.38	$65.09	$4.99	$10.35
2012	$31.76	$69.21	$5.05	$11.01
2013	$32.14	$73.59	$5.11	$11.71
2014	$32.51	$78.20	$5.17	$12.44
2015	$32.89	$83.08	$5.23	$13.21
2016	$33.06	$87.71	$5.26	$13.95
2017	$33.26	$92.71	$5.29	$14.75
2018	$33.34	$97.61	$5.30	$15.53
2019	$33.44	$102.84	$5.32	$16.36
2020	$33.53	$108.35	$5.33	$17.23
2021	$33.57	$113.94	$5.34	$18.12
2022	$33.60	$119.77	$5.34	$19.05

1993 TO 2022 FPL SHORT–TERM/DRI LONG–TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED CONSTANT 1992 DOLLAR & NOMINAL DOLLAR FUEL OIL PRICES

FPL SHORT – TERM/DRI AUGUST, 1992 LONG – TERM BASE CASE FORECAST

MARCH 1993

YEAR	***********DISTILLATE FUEL OIL***********				***********2.5% SULFUR FUEL OIL*********				***********1.5% SULFUR FUEL OIL*********			
	----$/BBL----		---$/MMBTU---		----$/BBL----		---$/MMBTU---		----$/BBL----		---$/MMBTU---	
	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL	1992$	NOMINAL
1993	$26.00	$26.66	$4.46	$4.58	$14.41	$14.76	$2.29	$2.35	$16.12	$16.51	$2.56	$2.63
1994	$26.14	$27.58	$4.49	$4.73	$15.79	$16.63	$2.51	$2.64	$17.83	$18.78	$2.84	$2.99
1995	$26.73	$29.01	$4.59	$4.98	$17.21	$18.64	$2.74	$2.96	$19.81	$21.47	$3.15	$3.41
1996	$27.03	$30.10	$4.64	$5.17	$17.77	$19.75	$2.83	$3.14	$20.65	$22.97	$3.28	$3.65
1997	$27.37	$31.41	$4.70	$5.39	$18.89	$21.63	$3.00	$3.44	$21.11	$24.19	$3.36	$3.85
1998	$27.83	$33.09	$4.78	$5.68	$20.00	$23.74	$3.18	$3.78	$21.58	$25.62	$3.43	$4.08
1999	$28.31	$34.97	$4.86	$6.00	$20.37	$25.12	$3.24	$4.00	$22.17	$27.35	$3.53	$4.35
2000	$28.88	$37.15	$4.96	$6.38	$20.63	$26.49	$3.28	$4.21	$22.65	$29.10	$3.60	$4.63
2001	$29.63	$39.71	$5.09	$6.82	$21.35	$28.57	$3.40	$4.54	$23.36	$31.27	$3.71	$4.97
2002	$30.60	$42.68	$5.25	$7.33	$22.16	$30.86	$3.52	$4.91	$24.17	$33.67	$3.84	$5.36
2003	$31.66	$45.94	$5.43	$7.89	$23.06	$33.41	$3.67	$5.31	$25.08	$36.35	$3.99	$5.78
2004	$32.73	$49.42	$5.62	$8.48	$24.05	$36.26	$3.82	$5.77	$26.06	$39.30	$4.14	$6.25
2005	$33.52	$52.74	$5.75	$9.05	$24.77	$38.92	$3.94	$6.19	$26.78	$42.09	$4.26	$6.70
2006	$34.26	$56.31	$5.88	$9.67	$25.54	$41.93	$4.06	$6.67	$27.46	$45.09	$4.37	$7.17
2007	$35.05	$60.21	$6.02	$10.34	$26.18	$44.92	$4.16	$7.15	$28.19	$48.39	$4.48	$7.70
2008	$35.89	$64.58	$6.16	$11.09	$26.85	$48.25	$4.27	$7.67	$28.86	$51.87	$4.59	$8.25
2009	$36.57	$68.94	$6.28	$11.83	$27.44	$51.66	$4.36	$8.22	$29.46	$55.48	$4.69	$8.83
2010	$37.18	$73.52	$6.38	$12.62	$27.98	$55.27	$4.45	$8.79	$30.00	$59.28	$4.77	$9.43
2011	$37.66	$78.17	$6.47	$13.42	$28.36	$58.81	$4.51	$9.35	$30.37	$62.99	$4.83	$10.02
2012	$38.10	$83.08	$6.54	$14.26	$28.74	$62.61	$4.57	$9.96	$30.75	$67.00	$4.89	$10.66
2013	$38.48	$88.17	$6.61	$15.14	$29.12	$66.65	$4.63	$10.60	$31.13	$71.27	$4.95	$11.34
2014	$38.80	$93.40	$6.66	$16.03	$29.49	$70.91	$4.69	$11.28	$31.51	$75.78	$5.01	$12.05
2015	$39.02	$98.64	$6.70	$16.93	$29.87	$75.42	$4.75	$12.00	$31.88	$80.52	$5.07	$12.81
2016	$39.12	$103.85	$6.72	$17.83	$30.04	$79.67	$4.78	$12.67	$32.05	$85.02	$5.10	$13.52
2017	$39.20	$109.35	$6.73	$18.77	$30.25	$84.29	$4.81	$13.41	$32.26	$89.92	$5.13	$14.30
2018	$39.27	$115.05	$6.74	$19.75	$30.32	$88.74	$4.82	$14.11	$32.33	$94.65	$5.14	$15.05
2019	$39.37	$121.15	$6.76	$20.80	$30.42	$93.52	$4.84	$14.88	$32.43	$99.73	$5.16	$15.86
2020	$39.46	$127.58	$6.77	$21.90	$30.51	$98.56	$4.85	$15.68	$32.52	$105.08	$5.17	$16.71
2021	$39.49	$134.10	$6.78	$23.02	$30.55	$103.65	$4.86	$16.49	$32.56	$110.50	$5.18	$17.58
2022	$39.51	$140.92	$6.78	$24.19	$30.58	$108.97	$4.86	$17.33	$32.60	$116.20	$5.18	$18.48

1993 TO 2022 FPL SHORT-TERM/DRI LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES

DELIVERED 1992 DOLLAR & NOMINAL DOLLAR NATURAL GAS PRICES IN DOLLARS PER MMBTU & NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY
FPL SHORT-TERM/DRI AUGUST, 1992 LONG-TERM BASE CASE FORECAST

MARCH 1993

YEAR	TOTAL DELIVERED NATURAL GAS PRICE (SEE NOTE 1) ******NON-FIRM**** ******SERVICE****** ******$/MMBTU****** 1992$	NOMINAL	WEIGHTED AVERAGE ***PHASE II AND III*** ***FIRM SERVICE**** ******$/MMBTU****** 1992$	NOMINAL	WEIGHTED AVERAGE ***FIRM/NON-FIRM*** ********PRICE******** ********$/MMBTU****** 1992$	NOMINAL	*NATURAL GAS AVAILABILITY** (SEE NOTE 2) **MILLION CUBIC FEET PER DAY** NON-FIRM SERVICE	FIRM SERVICE	TOTAL SYSTEM	SPOT NATURAL GAS DELIVERED TO THE FGT SYSTEM @ USGC *******$/MMBTU****** 1992$	NOMINAL	*NATURAL GAS TRANSPORTATION DEMAND CHARGE* (SEE NOTE 3) PHASE II $/MMBTU NOMINAL	PHASE II MILLIONS OF CUBIC FEET/DAY	PHASE II MILLIONS OF DOLLARS PER YEAR	PHASE III $/MMBTU NOMINAL	PHASE III MILLIONS OF CUBIC FEET/DAY	PHASE III MILLIONS OF DOLLARS PER YEAR
1993	$2.42	$2.49	$2.58	$2.64	$2.56	$2.63	42	332	374	$1.92	$1.97	$0.32	332	$38.3	$0.75	4	$1.0
1994	$2.48	$2.63	$2.78	$2.92	$2.73	$2.89	40	336	378	$1.98	$2.09	$0.32	332	$38.3	$0.75	97	$26.4
1995	$2.54	$2.76	$2.94	$3.20	$2.90	$3.18	37	429	466	$2.06	$2.24	$0.32	332	$38.3	$0.75	200	$54.8
1996	$2.61	$2.92	$3.02	$3.38	$2.95	$3.30	105	532	637	$2.13	$2.38	$0.32	332	$38.4	$0.75	200	$54.7
1997	$2.66	$3.06	$3.04	$3.51	$2.98	$3.44	93	532	625	$2.18	$2.51	$0.32	332	$38.3	$0.75	200	$54.7
1998	$2.70	$3.22	$3.06	$3.65	$3.01	$3.60	81	532	613	$2.22	$2.65	$0.32	332	$38.2	$0.75	200	$54.7
1999	$2.80	$3.48	$3.14	$3.90	$3.10	$3.85	69	532	601	$2.35	$2.91	$0.32	332	$38.3	$0.75	200	$54.8
2000	$2.93	$3.78	$3.24	$4.18	$3.20	$4.14	58	532	590	$2.47	$3.19	$0.32	332	$38.4	$0.75	200	$54.7
2001	$3.10	$4.17	$3.37	$4.53	$3.34	$4.50	48	532	580	$2.64	$3.55	$0.32	332	$38.3	$0.75	200	$54.7
2002	$3.30	$4.62	$3.51	$4.92	$3.50	$4.90	43	532	575	$2.83	$3.96	$0.32	332	$38.3	$0.75	200	$54.7
2003	$3.48	$5.07	$3.66	$5.34	$3.65	$5.32	38	532	570	$3.01	$4.38	$0.32	332	$38.3	$0.75	200	$54.8
2004	$3.67	$5.56	$3.82	$5.78	$3.81	$5.77	33	532	565	$3.19	[illegible]	$0.32	332	$38.4	$0.75	200	$54.7
2005	$3.79	$5.98	$3.89	$6.14	$3.88	$6.13	49	511	560	$3.31	$5.23	$0.32	311	$35.9	$0.75	200	$54.7
2006	$3.89	$6.42	$3.92	$6.46	$3.91	$6.46	80	480	560	$3.41	$5.62	$0.32	280	$32.3	$0.75	200	$54.7
2007	$4.00	$6.89	$4.01	$6.91	$4.01	$6.90	79	480	558	$3.51	$6.05	$0.32	280	$32.3	$0.75	200	$54.8
2008	$4.10	$7.39	$4.10	$7.39	$4.10	$7.39	76	480	556	$3.61	$6.51	$0.32	280	$32.4	$0.75	200	$54.7
2009	$4.17	$7.86	$4.15	$7.85	$4.16	$7.86	74	480	554	$3.68	$6.96	$0.32	280	$32.3	$0.75	200	$54.7
2010	$4.23	$8.39	$4.19	$8.31	$4.19	$8.32	72	480	552	$3.74	$7.42	$0.32	280	$32.3	$0.75	200	$54.7
2011	$4.30	$8.96	$4.25	$8.84	$4.25	$8.86	70	480	550	$3.81	$7.93	$0.32	280	$32.3	$0.75	200	$54.8
2012	$4.34	$9.50	$4.28	$9.35	$4.29	$9.37	70	480	550	$3.85	$8.42	$0.32	280	$32.4	$0.75	200	$54.7
2013	$4.37	$10.05	$4.31	$9.90	$4.32	$9.92	70	480	550	$3.89	$8.94	$0.32	280	$32.3	$0.75	200	$54.7
2014	$4.39	$10.59	$4.33	$10.44	$4.33	$10.46	70	480	550	$3.92	$9.46	$0.32	280	$32.3	$0.75	200	$54.7
2015	$4.40	$11.16	$4.35	$11.02	$4.35	$11.04	70	480	550	$3.95	$10.01	$0.32	280	$32.3	$0.75	200	$54.8
2016	$4.40	$11.72	$4.35	$11.58	$4.35	$11.59	70	480	550	$3.96	$10.54	$0.32	280	$32.4	$0.75	200	$54.7
2017	$4.39	$12.27	$4.34	$12.14	$4.34	$12.15	70	480	550	$3.96	$11.08	$0.32	280	$32.3	$0.75	200	$54.7
2018	$4.37	$12.85	$4.33	$12.72	$4.34	$12.74	70	480	550	$3.96	$11.63	$0.32	280	$32.3	$0.75	200	$54.7
2019	$4.36	$13.46	$4.32	$13.34	$4.33	$13.35	70	480	550	$3.96	$12.22	$0.32	280	$32.3	$0.75	200	$54.8
2020	$4.35	$14.10	$4.31	$13.99	$4.32	$14.00	70	480	550	$3.96	$12.84	$0.32	280	$32.4	$0.75	200	$54.7
2021	$4.34	$14.77	$4.31	$14.66	$4.31	$14.66	70	480	550	$3.96	$13.49	$0.32	280	$32.3	$0.75	200	$54.7
2022	$4.33	$15.48	$4.30	$15.38	$4.30	$15.38	70	480	550	$3.96	$14.16	$0.32	280	$32.3			

NOTE 1: DELIVERED NATURAL GAS PRICES ASSUME THAT 100% OF THE PROJECTED FIRM AND NON-FIRM NATURAL GAS AVAILABILITY IS PURCHASED AND FULL TRANSPORTATION COSTS ARE INCLUDED
NOTE 2: THESE FIRM AND NON-FIRM VOLUMES REPRESENT AN ARITHMATIC AVERAGE OF THE TWELVE MONTHLY FIRM AND NON-FIRM AVAILABILITIES, RESPECTIVELY, WHICH CAN RANGE SIGNIFICANTLY DURING THE YEAR
SHOULD MONTHLY AVAILABILITIES BE REQUIRED, PLEASE CONTACT FUEL MANAGEMENT.
NOTE 3: THE MILLIONS OF DOLLARS PER YEAR FOR THE PHASE II AND PHASE III NATURAL GAS TRANSPORTATION DEMAND CHARGES ARE ADDITIVE

1993 TO 2022 FPL SHORT-TERM/DRI LONG-TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED NOMINAL DOLLAR COAL PRICES IN DOLLARS PER TON & PER MMBTU

FPL SHORT-TERM/DRI AUGUST, 1992 LONG-TERM BASE CASE FORECAST

MARCH 1993

FORECAST ASSUMES THAT THE MARTIN COAL PLANT WILL STARTUP IN 2000

	PLANT SCHERER UNIT 4				MARTIN PLANT: LOW SULFUR COAL				MARTIN PLANT: HIGH SULFUR COAL			
	WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL	
YEAR	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1993	$55.92	$2.33	$38.94	$1.68	$40.34	$1.65	$40.34	$1.65	$39.65	$1.72	$39.65	$1.72
1994	$38.41	$1.84	$25.75	$1.51	$41.31	$1.69	$41.31	$1.69	$40.56	$1.76	$40.56	$1.76
1995	$35.09	$1.77	$26.27	$1.55	$43.01	$1.76	$43.01	$1.76	$41.20	$1.79	$41.20	$1.79
1996	$35.49	$1.81	$26.85	$1.58	$44.74	$1.83	$44.74	$1.83	$41.87	$1.82	$41.87	$1.82
1997	$37.77	$1.90	$28.20	$1.66	$46.35	$1.90	$46.35	$1.90	$43.06	$1.87	$43.06	$1.87
1998	$35.67	$1.89	$29.09	$1.71	$48.11	$1.97	$48.11	$1.97	$44.51	$1.94	$44.51	$1.94
1999	$35.04	$1.91	$29.88	$1.76	$49.77	$2.04	$49.82	$2.04	$46.05	$2.00	$46.13	$2.01
2000	$37.79	$2.02	$30.69	$1.81	$51.63	$2.12	$51.78	$2.12	$47.86	$2.08	$48.22	$2.10
2001	$37.60	$2.04	$31.52	$1.85	$53.62	$2.20	$53.95	$2.21	$49.74	$2.16	$50.40	$2.19
2002	$38.40	$2.09	$32.39	$1.91	$55.66	$2.28	$56.23	$2.30	$51.66	$2.25	$52.62	$2.29
2003	$40.76	$2.18	$33.27	$1.96	$58.50	$2.40	$58.56	$2.40	$54.94	$2.39	$55.01	$2.39
2004	$40.68	$2.21	$34.18	$2.01	$60.70	$2.49	$61.02	$2.50	$57.06	$2.48	$57.50	$2.50
2005	$41.54	$2.27	$35.15	$2.07	$63.09	$2.59	$63.67	$2.61	$59.36	$2.58	$60.17	$2.62
2006	$44.89	$2.40	$36.20	$2.13	$65.71	$2.69	$66.52	$2.73	$61.89	$2.69	$63.09	$2.74
2007	$45.02	$2.44	$37.31	$2.19	$68.47	$2.81	$69.51	$2.85	$64.56	$2.81	$66.18	$2.88
2008	$45.54	$2.48	$38.49	$2.26	$72.58	$2.97	$72.74	$2.98	$69.36	$3.02	$69.51	$3.02
2009	$39.89	$2.35	$39.76	$2.34	$75.76	$3.11	$76.08	$3.12	$72.49	$3.15	$73.02	$3.17
2010	$41.39	$2.43	$41.10	$2.42	$79.19	$3.25	$79.71	$3.27	$75.86	$3.30	$76.81	$3.34
2011	$42.99	$2.53	$42.54	$2.50	$82.88	$3.40	$83.70	$3.43	$79.44	$3.45	$80.82	$3.51
2012	$44.69	$2.63	$44.06	$2.59	$86.89	$3.56	$88.21	$3.62	$83.26	$3.62	$85.10	$3.70
2013	$45.68	$2.69	$45.68	$2.69	$93.02	$3.81	$93.29	$3.82	$89.31	$3.88	$89.60	$3.90
2014	$47.52	$2.80	$47.38	$2.79	$97.69	$4.00	$98.95	$4.06	$93.59	$4.07	$94.34	$4.10
2015	$49.37	$2.90	$49.09	$2.89	$102.57	$4.20	$104.92	$4.30	$98.06	$4.26	$99.31	$4.32
2016	$51.32	$3.02	$50.88	$2.99	$107.83	$4.42	$111.53	$4.57	$102.78	$4.47	$104.57	$4.55
2017	$53.37	$3.14	$52.78	$3.10	$113.36	$4.65	$118.45	$4.85	$107.78	$4.69	$110.18	$4.79
2018	$54.74	$3.22	$54.74	$3.22	$125.28	$5.13	$125.72	$5.15	$115.61	$5.03	$116.06	$5.05
2019	$56.94	$3.35	$56.82	$3.34	$131.59	$5.39	$133.32	$5.46	$121.19	$5.27	$122.27	$5.32
2020	$59.26	$3.49	$58.99	$3.47	$138.27	$5.67	$141.40	$5.80	$127.11	$5.53	$128.89	$5.60
2021	$61.68	$3.63	$61.25	$3.60	$145.20	$5.95	$149.75	$6.14	$133.27	$5.79	$135.78	$5.90
2022	$64.20	$3.78	$63.61	$3.74	$152.45	$6.25	$158.40	$6.49	$139.77	$6.08	$143.08	$6.22

1993 TO 2022 FPL SHORT–TERM/DRI LONG–TERM FOSSIL FUEL PRICE FORECAST
CONSTANT 1992 DOLLAR AND NOMINAL DOLLAR PRICES.

DELIVERED NOMINAL DOLLAR COAL & ORIMULSION PRICES IN DOLLARS PER TON & PER MMBTU
FPL SHORT – TERM/DRI AUGUST, 1992 LONG – TERM BASE CASE FORECAST

MARCH 1993

YEAR	ST. JOHNS RIVER POWER PARK COAL WEIGHTED AVERAGE NOMINAL $/TON	$/MMBTU	SPOT PRICE NOMINAL $/TON	$/MMBTU	ORIMULSION ASSUMING A 1998 PLANT STARTUP CONTRACT PRICE NOMINAL $/TON	$/MMBTU	SPOT PRICE NOMINAL $/TON	$/MMBTU
1993	$38.34	$1.56	$31.12	$1.26	$40.08	$1.57	$31.99	$1.26
1994	$38.63	$1.57	$31.47	$1.26	$40.91	$1.61	$32.10	$1.26
1995	$39.37	$1.60	$32.61	$1.31	$42.02	$1.65	$33.29	$1.31
1996	$40.48	$1.65	$34.27	$1.39	$42.97	$1.69	$35.42	$1.39
1997	$37.76	$1.56	$35.75	$1.51	$42.25	$1.66	$38.59	$1.51
1998	$38.86	$1.62	$36.54	$1.59	$43.56	$1.71	$40.47	$1.59
1999	$39.80	$1.66	$36.68	$1.59	$45.17	$1.77	$40.63	$1.59
2000	$40.37	$1.69	$37.39	$1.63	$45.85	$1.80	$41.42	$1.63
2001	$41.71	$1.74	$38.11	$1.66	$47.60	$1.87	$42.22	$1.66
2002	$41.69	$1.79	$40.86	$1.78	$48.04	$1.89	$45.27	$1.78
2003	$41.57	$1.81	$42.78	$1.86	$47.75	$1.87	$47.39	$1.86
2004	$43.21	$1.88	$44.77	$1.95	$47.13	$1.85	$49.60	$1.95
2005	$46.49	$2.02	$46.91	$2.04	$51.30	$2.01	$51.97	$2.04
2006	$48.49	$2.11	$49.26	$2.14	$53.35	$2.09	$54.57	$2.14
2007	$50.60	$2.20	$51.73	$2.25	$55.52	$2.18	$57.31	$2.25
2008	$53.88	$2.30	$57.69	$2.36	$57.89	$2.27	$60.24	$2.36
2009	$56.27	$2.40	$60.36	$2.47	$60.40	$2.37	$63.03	$2.47
2010	$63.19	$2.70	$63.26	$2.59	$69.97	$2.75	$66.06	$2.59
2011	$66.14	$2.83	$66.47	$2.72	$73.11	$2.87	$69.41	$2.72
2012	$69.35	$2.96	$70.12	$2.87	$76.46	$3.00	$73.22	$2.87
2013	$72.82	$3.11	$74.25	$3.04	$80.00	$3.14	$77.54	$3.04
2014	$75.15	$3.27	$74.23	$3.23	$83.69	$3.28	$82.23	$3.23
2015	$77.49	$3.37	$78.20	$3.40	$85.51	$3.36	$86.64	$3.40
2016	$81.23	$3.53	$82.41	$3.58	$89.42	$3.51	$91.30	$3.58
2017	$85.19	$3.70	$86.90	$3.78	$93.56	$3.67	$96.27	$3.78
2018	$89.33	$3.88	$91.61	$3.98	$97.88	$3.84	$101.49	$3.98
2019	$93.70	$4.07	$96.59	$4.20	$102.43	$4.02	$107.01	$4.20
2020	$100.98	$4.39	$101.90	$4.43	$111.43	$4.37	$112.89	$4.43
2021	$105.87	$4.60	$107.43	$4.67	$116.55	$4.57	$119.02	$4.67
2022	$111.03	$4.83	$113.30	$4.93	$121.93	$4.79	$125.51	$4.93

FPL

Inter-Office Correspondence

To: R. J. Pawlyk | Date: March 28, 1994

From: E. Ungar | Department: PGBU Business Systems

Subject: **FPL BASE CASE FOSSIL FUEL PRICE FORECAST (1994-2023)**

In response to your request, attached is an updated FPL Base Case Fossil Fuel Price Forecast. The forecast includes future prices for crude oil, residual and distillate fuel oil, natural gas, coal, Orimulsion, and petroleum coke as well as future quantities of natural gas to be made available to FPL. This forecast represents the combination of the November, 3 1993 FPL Short-Term Fossil Fuel Price Forecast and the March, 1994 DRI Long-Term Forecast.

The following comparisons illustrate the most significant changes between this update and last year's (March, 1993) forecast:

- The delivered nominal dollar price of 1% sulfur residual fuel oil in the year 2000 is 27% lower than last year's forecast primarily due to: (1) lower crude oil prices; (2) significantly lower residual fuel oil demand, mainly in the electric utility and industrial sectors; and (3) the cumulative impact of a reduction in DRI's projected inflation rate.

- The delivered nominal price of natural gas in the year 2000 is 13% lower than last year's forecast mainly due to: (1) a more optimistic assessment of the level of long-term natural gas deliverability; (2) competition from lower priced residual fuel oil and coal; and (3) the cumulative impact of a reduction in DRI's projected inflation rate.

If you have any questions concerning the underlying assumptions supporting the updated Fossil Fuel Price Forecast, or the resulting forecasted values, please contact Eugene Ungar at 552-3412.

E. Ungar

E. Ungar

R. Silva

EU:
Attachments

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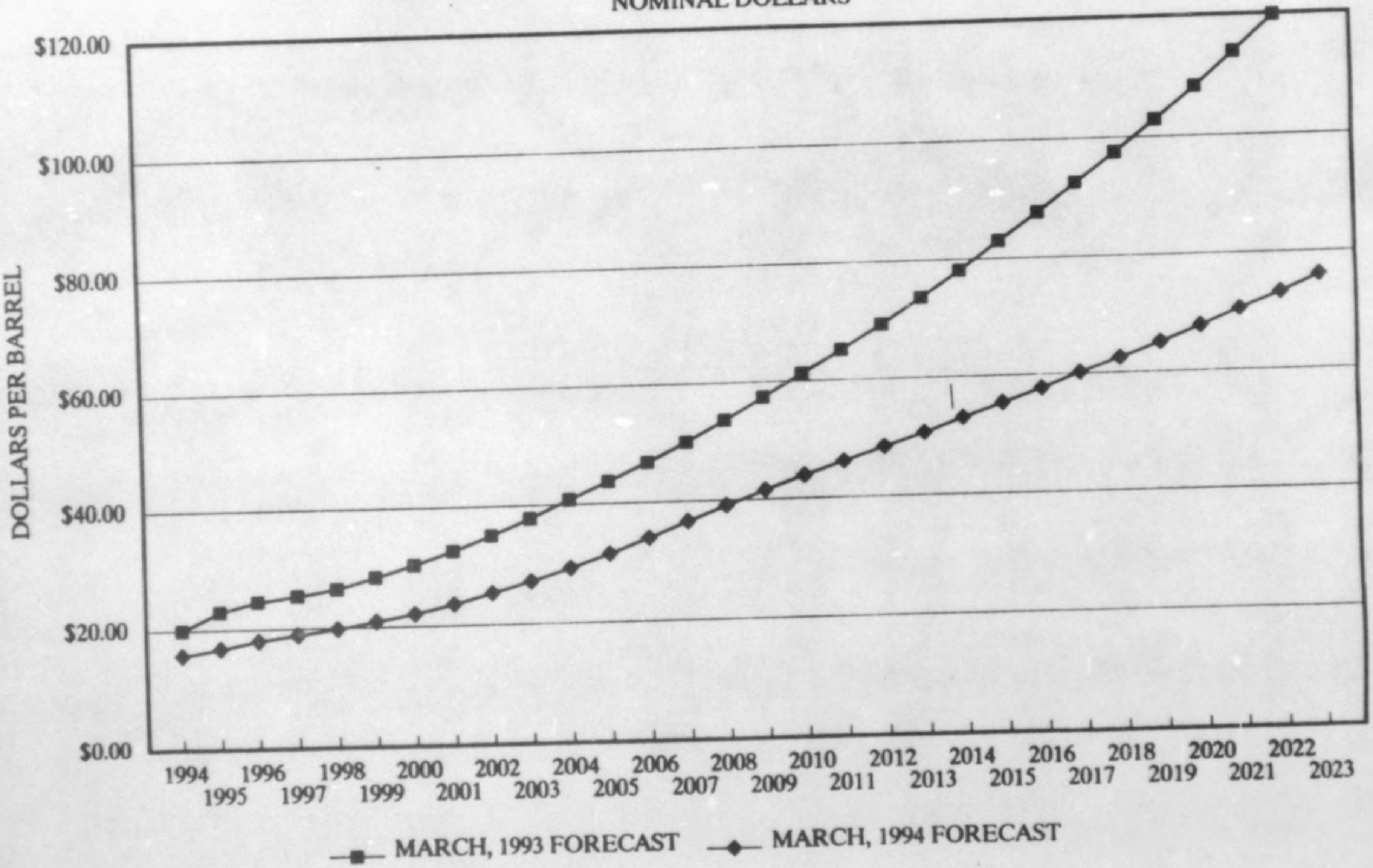
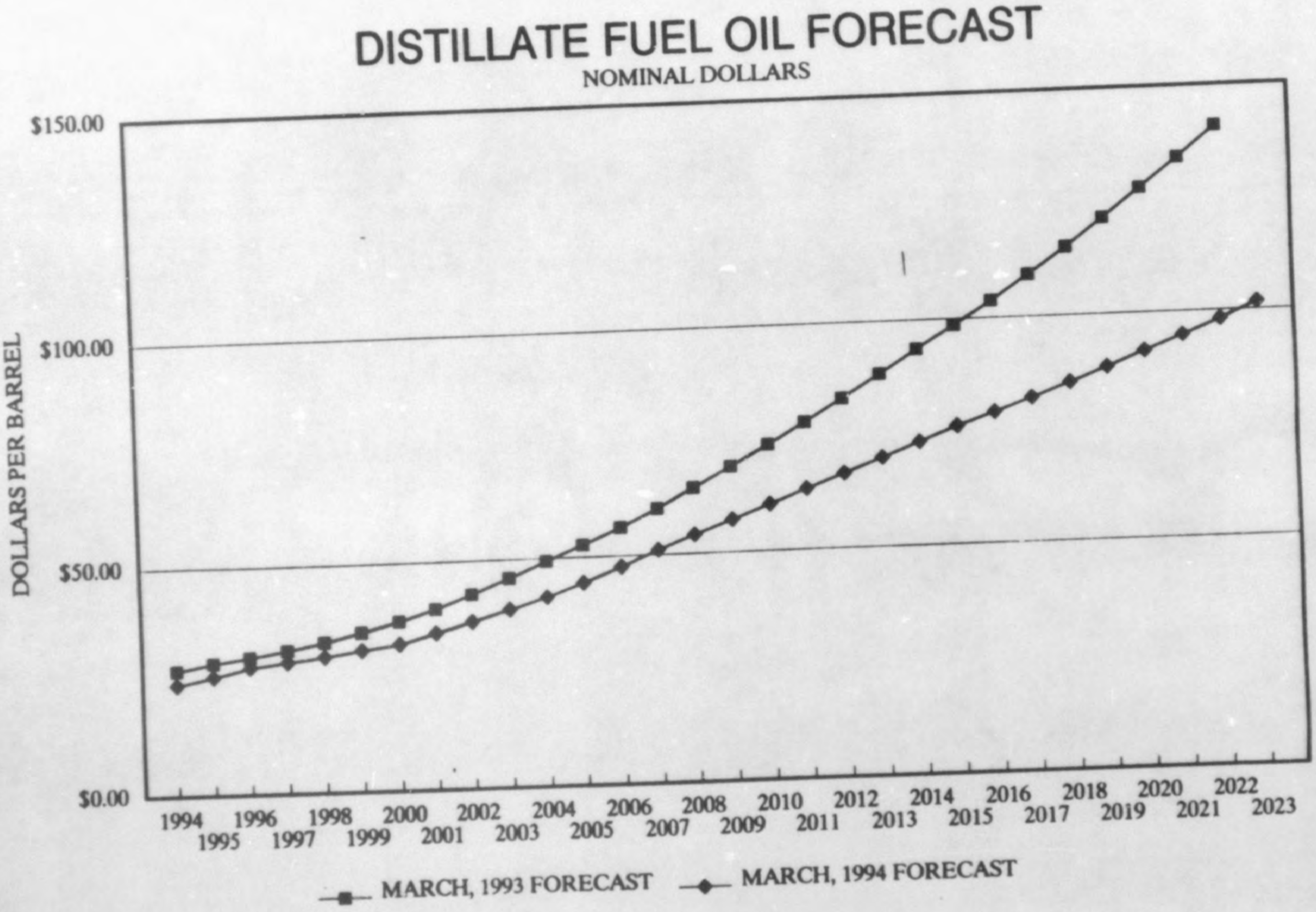
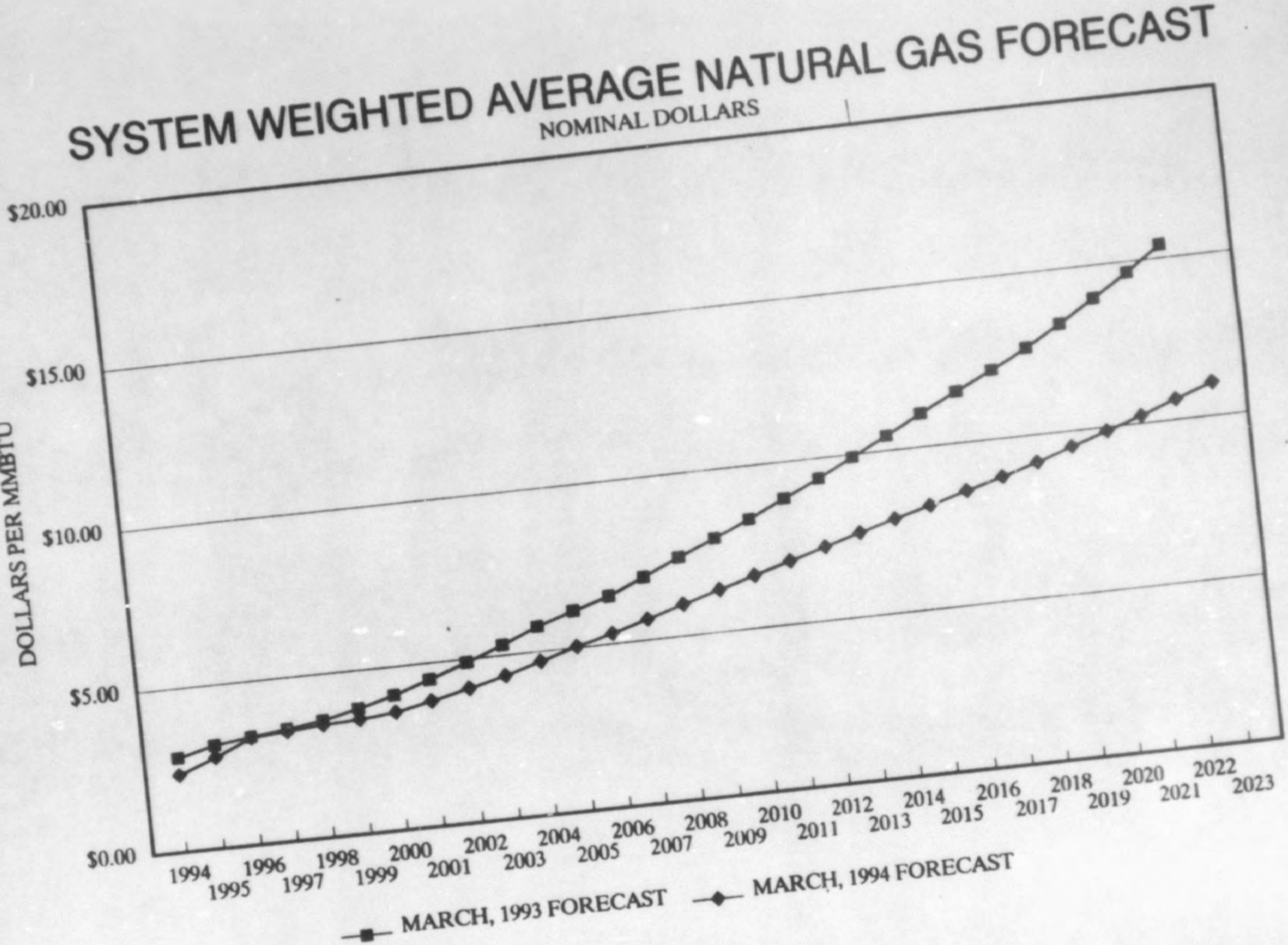
1% SULFUR RESIDUAL FUEL OIL FORECAST

NOMINAL DOLLARS




DISTILLATE FUEL OIL FORECAST
NOMINAL DOLLARS
DOLLARS PER BARREL
$150.00
$100.00
$50.00
$0.00
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
MARCH, 1993 FORECAST
MARCH, 1994 FORECAST


SYSTEM WEIGHTED AVERAGE NATURAL GAS FORECAST
NOMINAL DOLLARS
DOLLARS PER MMBTU
$20.00
$15.00
$10.00
$5.00
$0.00
1994
1995
1996
1997
1998
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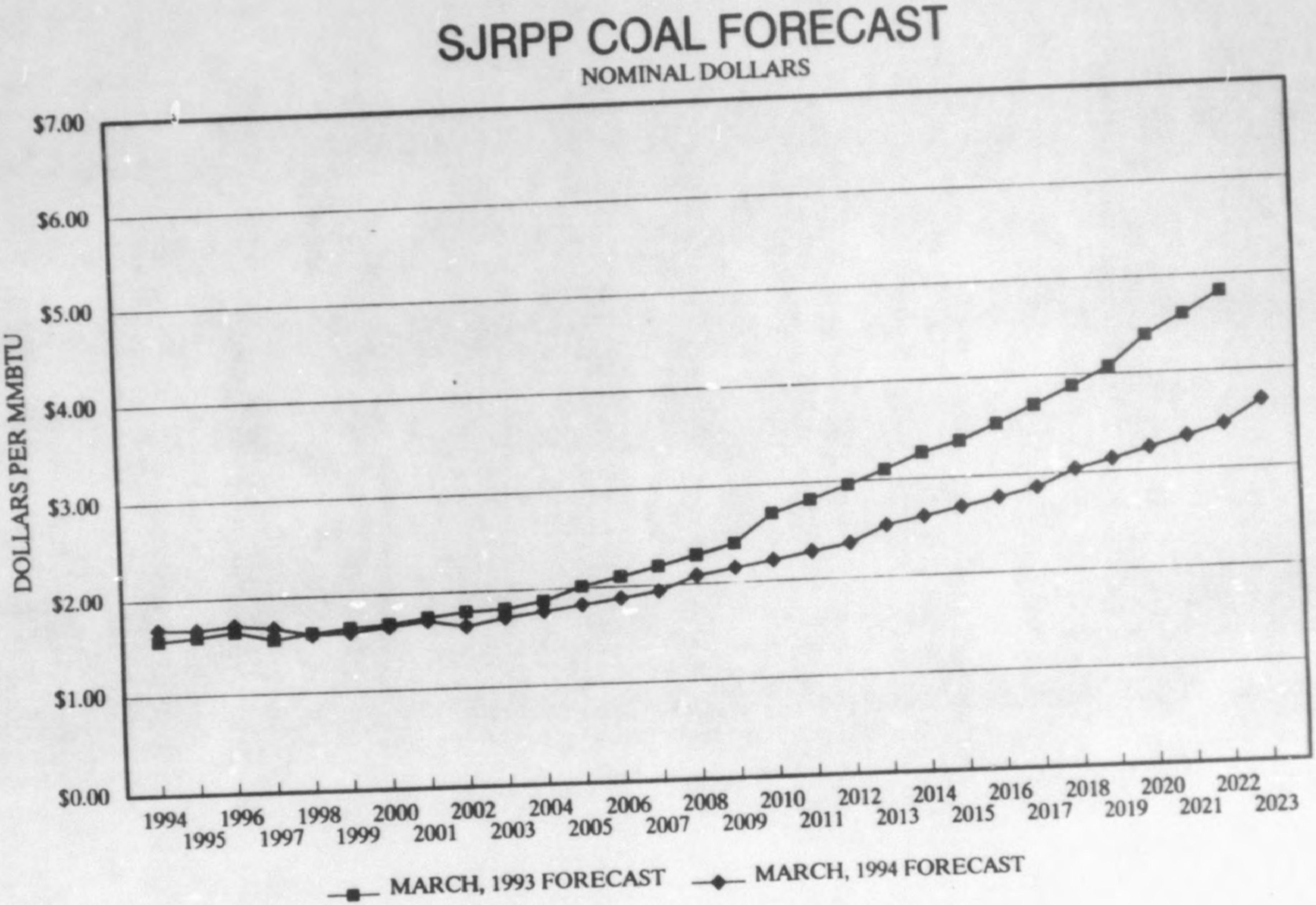
2023
MARCH, 1993 FORECAST
MARCH, 1994 FORECAST


SJRPP COAL FORECAST
NOMINAL DOLLARS
DOLLARS PER MMBTU
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1994
1995
1996
1997
1998
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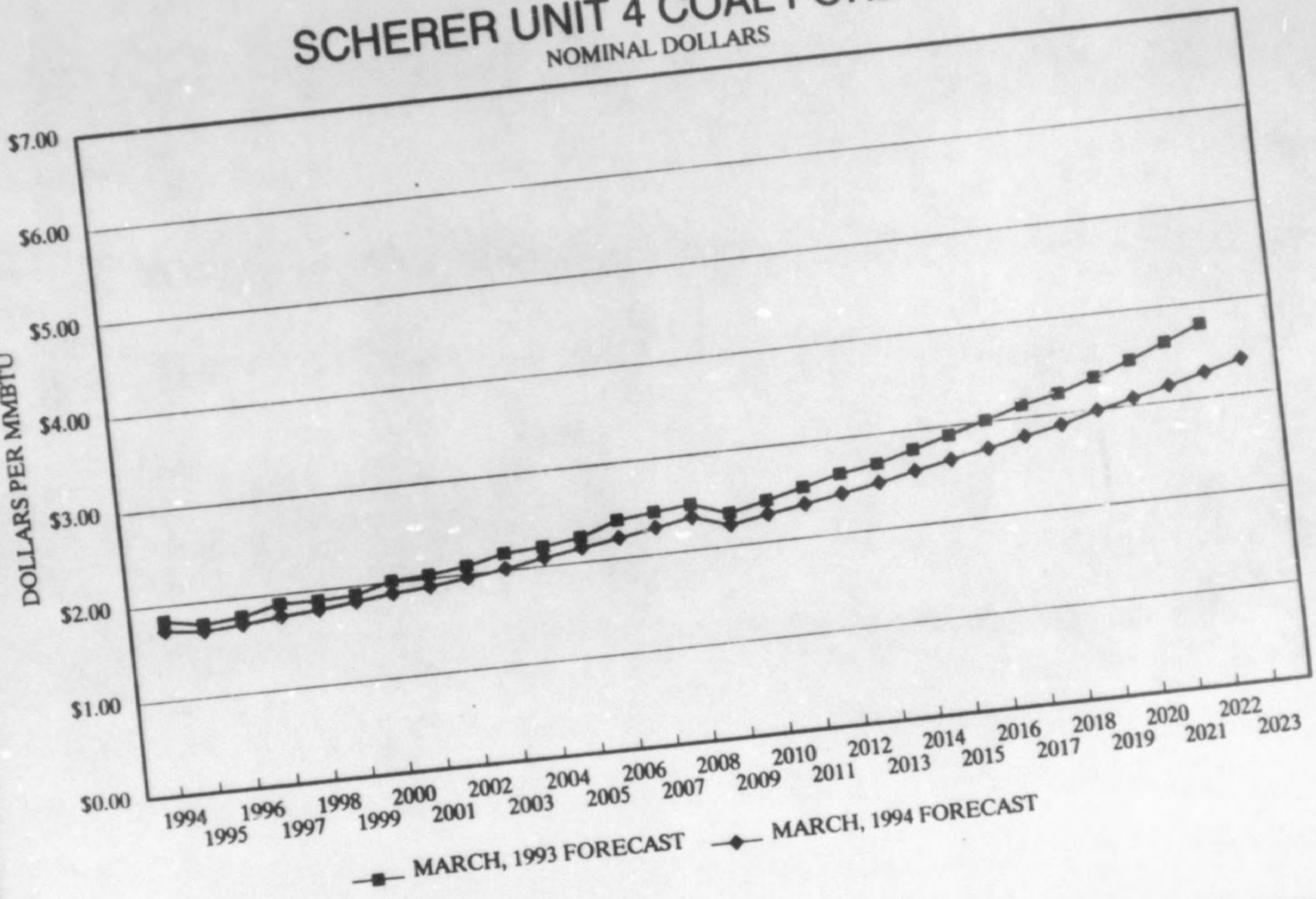
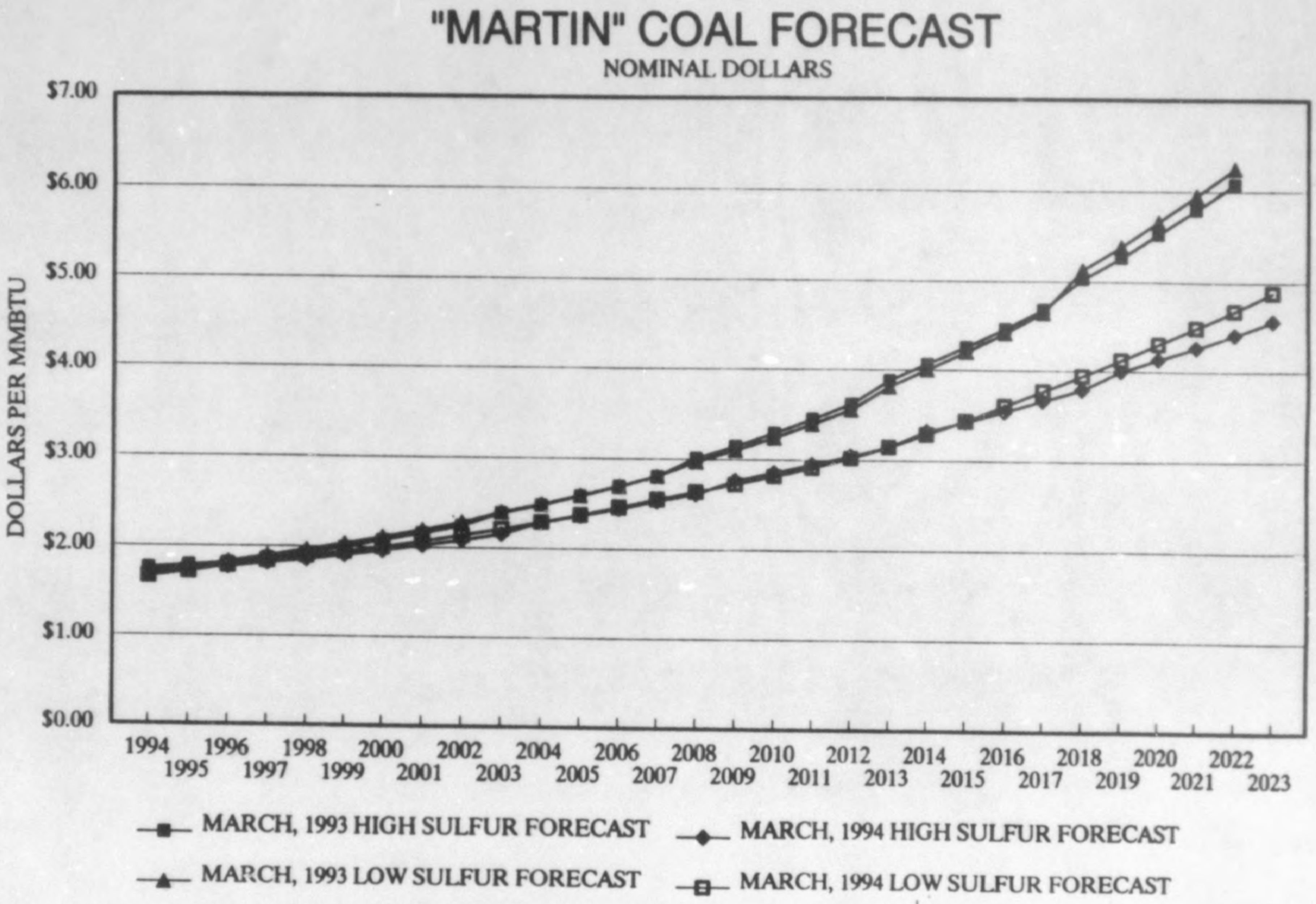
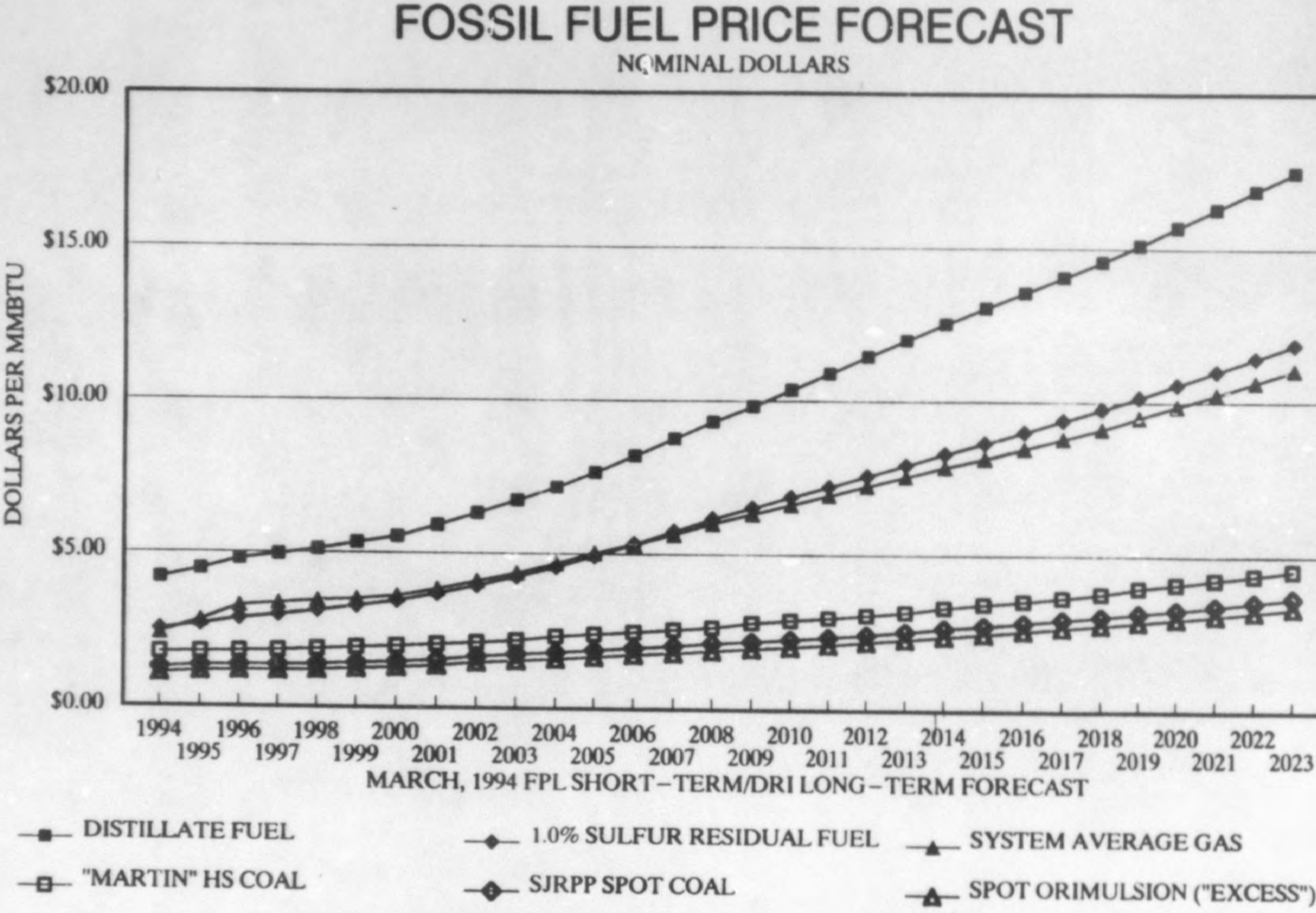
MARCH, 1993 FORECAST
MARCH, 1994 FORECAST

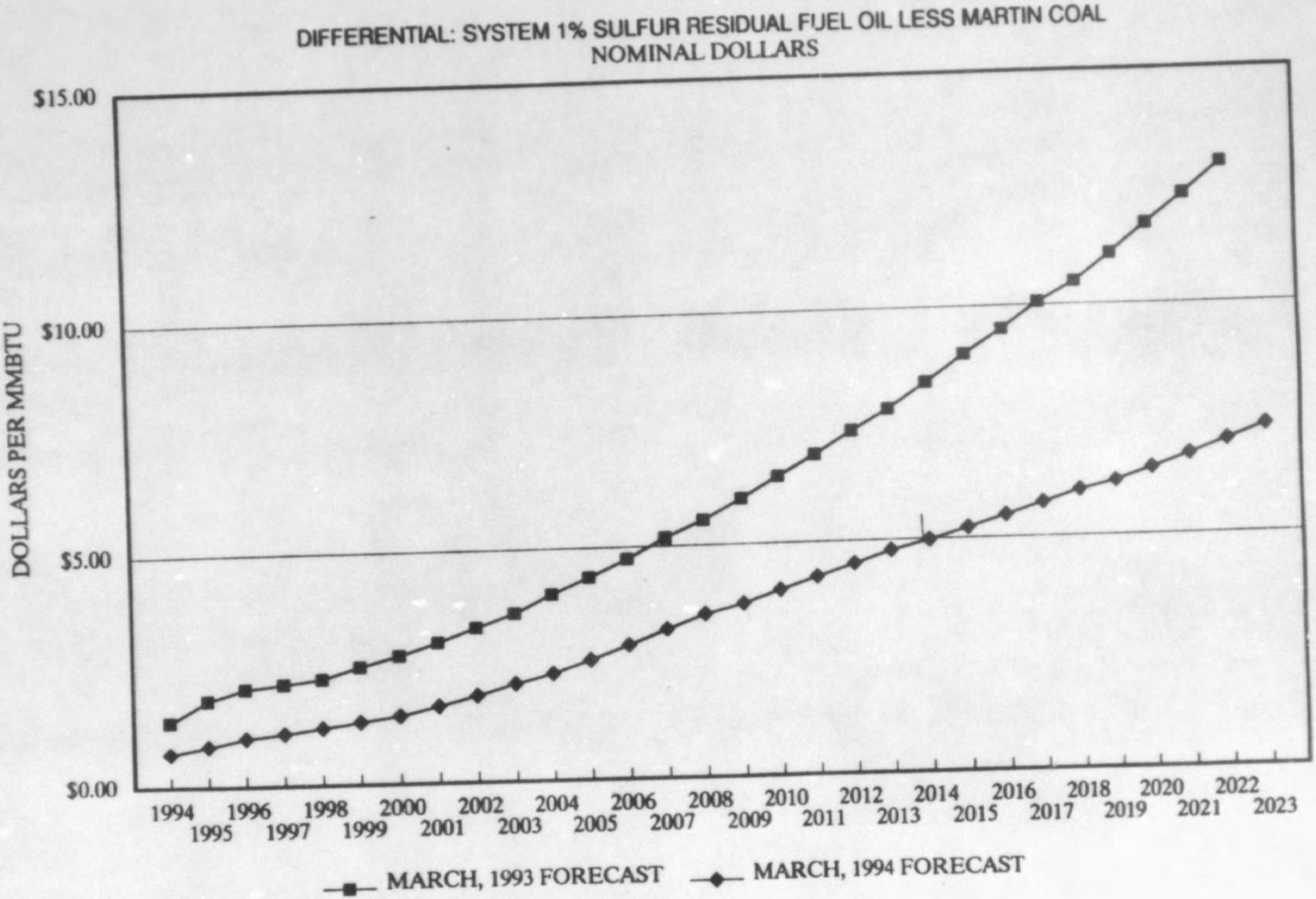
SCHERER UNIT 4 COAL FORECAST

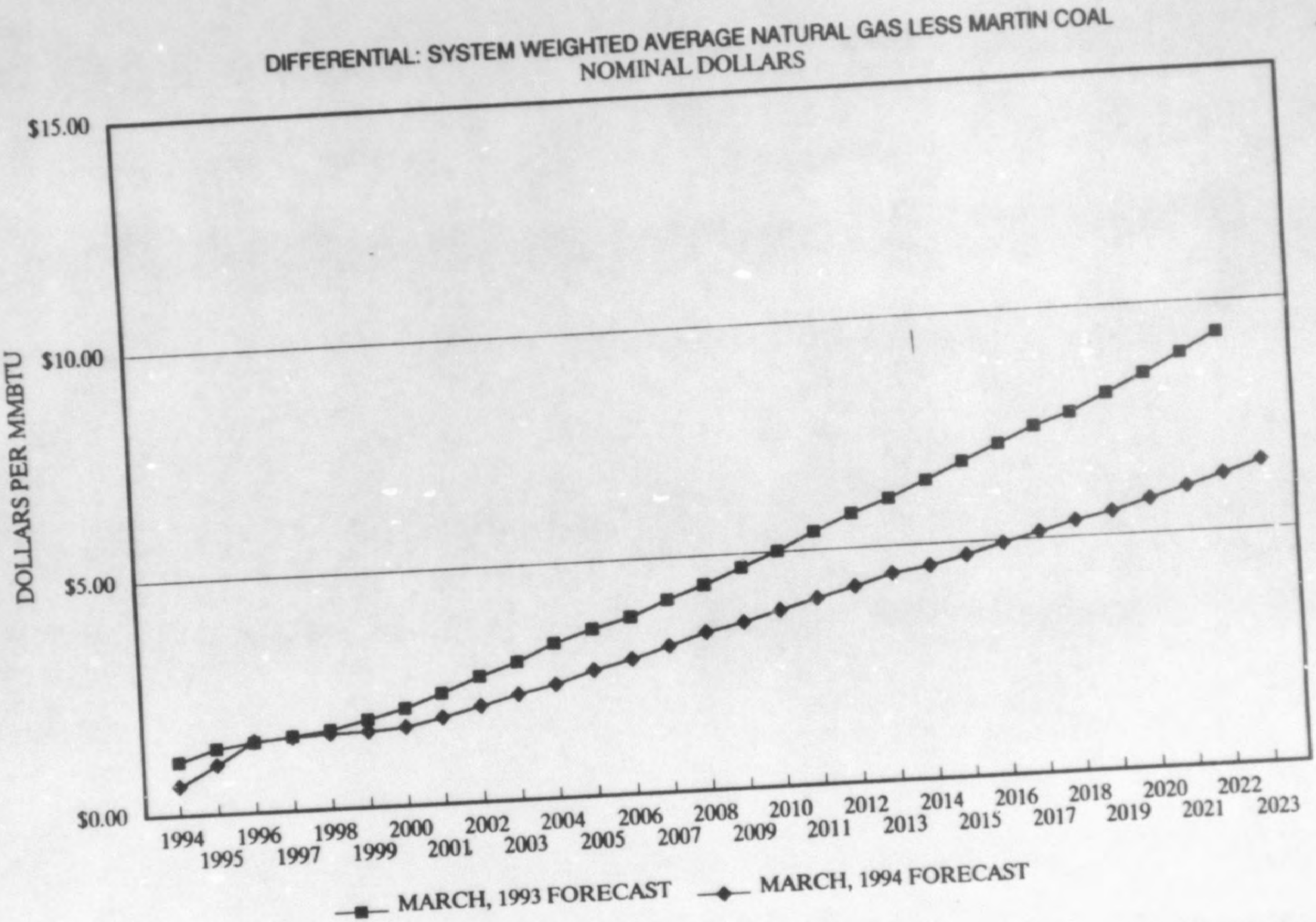
NOMINAL DOLLARS




"MARTIN" COAL FORECAST
NOMINAL DOLLARS
DOLLARS PER MMBTU
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
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
MARCH, 1993 HIGH SULFUR FORECAST
MARCH, 1994 HIGH SULFUR FORECAST
MARCH, 1993 LOW SULFUR FORECAST
MARCH, 1994 LOW SULFUR FORECAST


FOSSIL FUEL PRICE FORECAST
NOMINAL DOLLARS
$20.00
$15.00
$10.00
$5.00
$0.00
DOLLARS PER MMBTU
1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022
1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015 2017 2019 2021 2023
MARCH, 1994 FPL SHORT-TERM/DRI LONG-TERM FORECAST
DISTILLATE FUEL
1.0% SULFUR RESIDUAL FUEL
SYSTEM AVERAGE GAS
"MARTIN" HS COAL
SJRPP SPOT COAL
SPOT ORIMULSION ("EXCESS")


DIFFERENTIAL: SYSTEM 1% SULFUR RESIDUAL FUEL OIL LESS MARTIN COAL
NOMINAL DOLLARS
DOLLARS PER MMBTU
$15.00
$10.00
$5.00
$0.00
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
MARCH, 1993 FORECAST
MARCH, 1994 FORECAST


DIFFERENTIAL: SYSTEM WEIGHTED AVERAGE NATURAL GAS LESS MARTIN COAL
NOMINAL DOLLARS
DOLLARS PER MMBTU
$15.00
$10.00
$5.00
$0.00
1994
1995
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MARCH, 1993 FORECAST
MARCH, 1994 FORECAST

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

NOMINAL DOLLAR CRUDE OIL, DELIVERED DISTILLATE (NO. 2) & U.S.G.C. RESIDUAL & DISTILLATE FUEL OIL PRICES

MARCH 1994

	*******NOMINAL CRUDE OIL PRICES*********				(SEE NOTE 1)		(SEE NOTE 2)		******PLATT'S LOW POSTING @ USGC******				******PLATT'S LOW POSTING @ USGC******			
			****WEST TEXAS*****		*****0.5% SULFUR******		*****0.3% SULFUR******		****1.0% SULFUR****		****3.0% SULFUR****		****0.5% SULFUR****		****0.3% SULFUR****	
	ARABIAN LIGHT		***INTERMEDIATE****		**DISTILLATE FUEL OIL** DELIVERED NOMINAL		**DISTILLATE FUEL OIL* DELIVERED NOMINAL		**RESIDUAL FUEL OIL* NOMINAL @ USGC		*RESIDUAL FUEL OIL* NOMINAL @ USGC		*DISTILLATE FUEL OIL* NOMINAL @ USGC		*DISTILLATE FUEL OIL NOMINAL @ USGC	
YEAR	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	CENTS/GAL	$/BBL	CENTS/GAL	$/BBL
1994	$16.67	$2.87	$19.36	$3.34	$24.42	$4.19	$25.15	$4.32	$14.47	$2.26	$10.91	$1.70	54.90	$23.06	56.63	$23.79
1995	$17.49	$3.02	$20.15	$3.47	$26.06	$4.47	$26.78	$4.60	$15.53	$2.43	$11.56	$1.81	58.80	$24.70	60.50	$25.41
1996	$18.43	$3.18	$20.95	$3.61	$27.96	$4.80	$28.66	$4.92	$16.73	$2.61	$12.30	$1.92	63.30	$26.59	64.97	$27.29
1997	$19.73	$3.40	$22.40	$3.86	$28.85	$4.95	$29.54	$5.07	$17.59	$2.75	$13.19	$2.06	65.42	$27.48	67.06	$28.16
1998	$21.06	$3.63	$23.90	$4.12	$29.87	$5.13	$30.54	$5.24	$18.50	$2.89	$14.08	$2.20	67.83	$28.49	69.42	$29.16
1999	$22.55	$3.89	$25.61	$4.42	$31.05	$5.33	$31.70	$5.44	$19.52	$3.05	$15.02	$2.35	70.54	$29.62	72.08	$30.27
2000	$24.17	$4.17	$27.44	$4.73	$32.18	$5.52	$32.81	$5.63	$20.61	$3.22	$16.08	$2.51	73.13	$30.71	74.62	$31.34
2001	$25.94	$4.47	$29.44	$5.08	$34.32	$5.89	$34.95	$6.00	$22.10	$3.45	$17.25	$2.69	78.12	$32.81	79.62	$33.44
2002	$27.85	$4.80	$31.61	$5.45	$36.61	$6.28	$37.24	$6.39	$23.80	$3.72	$18.60	$2.91	83.45	$35.05	84.95	$35.68
2003	$29.92	$5.16	$33.98	$5.86	$39.07	$6.71	$39.70	$6.81	$25.66	$4.01	$20.11	$3.14	89.18	$37.45	90.66	$38.08
2004	$32.17	$5.55	$36.52	$6.30	$41.59	$7.14	$42.22	$7.25	$27.66	$4.32	$21.76	$3.40	95.05	$39.92	96.55	$40.55
2005	$34.59	$5.96	$39.28	$6.77	$44.45	$7.63	$45.06	$7.74	$29.86	$4.67	$23.55	$3.68	101.74	$42.73	103.23	$43.36
2006	$37.29	$6.43	$42.34	$7.30	$47.66	$8.18	$48.29	$8.29	$32.26	$5.04	$25.49	$3.98	109.23	$45.88	110.73	$46.51
2007	$40.18	$6.93	$45.62	$7.87	$51.07	$8.77	$51.69	$8.87	$34.82	$5.44	$27.56	$4.31	117.18	$49.22	118.66	$49.84
2008	$42.86	$7.39	$48.65	$8.39	$54.23	$9.31	$54.86	$9.42	$37.30	$5.83	$29.58	$4.62	124.57	$52.32	126.07	$52.95
2009	$45.37	$7.82	$51.52	$8.88	$57.23	$9.82	$57.86	$9.93	$39.52	$6.18	$31.41	$4.91	131.55	$55.25	133.05	$55.88
2010	$47.93	$8.26	$54.40	$9.38	$60.29	$10.35	$60.92	$10.46	$41.79	$6.53	$33.27	$5.20	138.58	$58.25	140.17	$58.87
2011	$50.43	$8.70	$57.26	$9.87	$63.42	$10.89	$64.05	$11.00	$43.98	$6.87	$35.02	$5.47	145.95	$61.30	147.45	$61.93
2012	$52.99	$9.14	$60.14	$10.37	$66.56	$11.43	$67.21	$11.54	$46.19	$7.22	$36.78	$5.75	153.31	$64.39	154.81	$65.02
2013	$55.54	$9.58	$63.06	$10.87	$69.77	$11.98	$70.40	$12.09	$48.42	$7.57	$38.56	$6.02	160.72	$67.50	162.22	$68.13
2014	$58.13	$10.02	$66.00	$11.38	$72.99	$12.53	$73.61	$12.64	$50.74	$7.93	$40.36	$6.31	168.20	$70.64	169.69	$71.27
2015	$60.63	$10.45	$68.84	$11.87	$76.12	$13.07	$76.75	$13.18	$52.96	$8.28	$42.11	$6.58	175.46	$73.69	176.96	$74.33
2016	$63.14	$10.89	$71.69	$12.38	$78.96	$13.56	$79.59	$13.66	$55.23	$8.63	$43.88	$6.83	182.03	$76.45	183.52	$77.08
2017	$65.78	$11.34	$74.88	$12.88	$81.92	$14.06	$82.56	$14.17	$57.58	$9.00	$45.31	$7.08	188.87	$79.32	190.37	$79.96
2018	$68.32	$11.78	$77.59	$13.38	$84.98	$14.59	$85.59	$14.69	$59.86	$9.35	$47.00	$7.34	195.88	$82.27	197.37	$82.90
2019	$70.97	$12.24	$80.81	$13.90	$88.12	$15.13	$88.75	$15.24	$62.26	$9.73	$48.75	$7.62	203.18	$85.34	204.68	$85.97
2020	$73.77	$12.72	$83.77	$14.44	$91.43	$15.70	$92.06	$15.80	$64.78	$10.12	$50.58	$7.90	210.83	$88.55	212.33	$89.18
2021	$76.66	$13.22	$87.06	$15.01	$94.73	$16.26	$95.36	$16.37	$67.38	$10.53	$52.42	$8.19	218.45	$91.75	219.94	$92.38
2022	$79.65	$13.73	$90.47	$15.60	$98.12	$16.84	$98.74	$16.95	$70.07	$10.95	$54.26	$8.48	226.27	$95.03	227.75	$95.66
2023	$82.78	$14.27	$94.00	$16.21	$101.76	$17.47	$102.27	$17.56	$72.89	$11.39	$56.24	$8.79	234.67	$98.56	235.90	$99.08

NOTE 1: THE 0.5% SULFUR DISTILLATE FUEL OIL IS FOR THE GAS TURBINES AT FT. MYERS, LAUDERDALE AND PORT EVERGLADES.
NOTE 2: THE 0.3% SULFUR DISTILLATE FUEL OIL IS FOR THE COMBINED CYCLE UNITS AT LAUDERDALE, MARTIN AND PUTNAM.

PGBU - BUSINESS SYSTEMS
MARCH, 1994 - EU

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR RESIDUAL (NO. 6) FUEL OIL PRICES BY SULFUR GRADE

MARCH 1994

YEAR	*****0.7% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		*****1.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		*****1.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		*****2.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		*****2.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		*****3.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL	
	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1994	$17.12	$2.68	$15.83	$2.47	$14.94	$2.33	$14.05	$2.20	$13.16	$2.06	$12.27	$1.92
1995	$18.29	$2.86	$16.90	$2.64	$15.91	$2.49	$14.92	$2.33	$13.92	$2.18	$12.93	$2.02
1996	$19.60	$3.06	$18.10	$2.83	$17.00	$2.56	$15.89	$2.48	$14.78	$2.31	$13.67	$2.14
1997	$20.67	$3.23	$18.96	$2.96	$17.82	$2.79	$16.69	$2.61	$15.63	$2.44	$14.57	$2.28
1998	$21.88	$3.42	$19.88	$3.11	$18.69	$2.92	$17.49	$2.73	$16.48	$2.57	$15.46	$2.42
1999	$23.17	$3.62	$20.94	$3.27	$19.69	$3.08	$18.43	$2.88	$17.44	$2.73	$16.45	$2.57
2000	$24.54	$3.83	$22.07	$3.45	$20.74	$3.24	$19.41	$3.03	$18.48	$2.89	$17.55	$2.74
2001	$26.26	$4.10	$23.61	$3.69	$22.19	$3.47	$20.78	$3.25	$19.77	$3.09	$18.76	$2.93
2002	$28.21	$4.41	$25.36	$3.96	$23.84	$3.73	$22.33	$3.49	$21.24	$3.32	$20.16	$3.15
2003	$30.35	$4.74	$27.27	$4.26	$25.67	$4.01	$24.05	$3.76	$22.89	$3.58	$21.72	$3.39
2004	$32.64	$5.10	$29.32	$4.58	$27.62	$4.32	$25.93	$4.05	$24.68	$3.86	$23.43	$3.66
2005	$35.16	$5.49	$31.59	$4.94	$29.78	$4.65	$27.98	$4.37	$26.63	$4.16	$25.28	$3.95
2006	$37.93	$5.93	$34.05	$5.32	$32.12	$5.02	$30.20	$4.72	$28.74	$4.49	$27.28	$4.26
2007	$40.84	$6.38	$36.67	$5.73	$34.60	$5.41	$32.55	$5.09	$30.98	$4.84	$29.41	$4.59
2008	$43.68	$6.82	$39.21	$6.13	$37.04	$5.79	$34.86	$5.45	$33.18	$5.18	$31.49	$4.92
2009	$46.24	$7.22	$41.50	$6.48	$39.22	$6.13	$36.96	$5.77	$35.16	$5.49	$33.39	$5.22
2010	$48.85	$7.63	$43.84	$6.85	$41.46	$6.48	$39.08	$6.11	$37.21	$5.81	$35.32	$5.52
2011	$51.37	$8.03	$46.10	$7.20	$43.60	$6.81	$41.10	$6.42	$39.12	$6.11	$37.13	$5.80
2012	$53.92	$8.43	$48.38	$7.56	$45.77	$7.15	$43.14	$6.74	$41.06	$6.42	$38.97	$6.09
2013	$56.51	$8.83	$50.68	$7.92	$47.94	$7.49	$45.19	$7.06	$43.00	$6.72	$40.82	$6.38
2014	$59.23	$9.25	$53.08	$8.29	$50.17	$7.84	$47.28	$7.39	$44.98	$7.03	$42.70	$6.67
2015	$61.87	$9.67	$55.39	$8.65	$52.36	$8.18	$49.31	$7.70	$46.91	$7.33	$44.53	$6.96
2016	$64.55	$10.09	$57.74	$9.02	$54.46	$8.51	$51.18	$8.00	$48.69	$7.61	$46.19	$7.22
2017	$67.34	$10.52	$60.18	$9.40	$56.66	$8.85	$53.13	$8.30	$50.52	$7.89	$47.91	$7.49
2018	$70.06	$10.95	$62.55	$9.77	$58.83	$9.19	$55.12	$8.61	$52.42	$8.19	$49.69	$7.76
2019	$72.91	$11.39	$65.05	$10.16	$61.11	$9.55	$57.20	$8.94	$54.36	$8.49	$51.54	$8.05
2020	$75.89	$11.86	$67.66	$10.57	$63.56	$9.93	$59.37	$9.28	$56.43	$8.82	$53.46	$8.35
2021	$79.01	$12.34	$70.36	$10.99	$65.95	$10.30	$61.54	$9.62	$58.47	$9.14	$55.40	$8.66
2022	$82.23	$12.85	$73.16	$11.43	$68.47	$10.70	$63.78	$9.96	$60.57	$9.46	$57.37	$8.96
2023	$85.61	$13.38	$76.09	$11.89	$71.10	$11.11	$66.12	$10.33	$62.78	$9.81	$59.44	$9.29

NOTE: RESIDUAL FUEL OIL PRICES ARE DELIVERED PRICES TO ALL FPL PLANT SITES.

PGBU – BUSINESS SYSTEMS
MARCH, 1994 – EU

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

MARCH 1994

COMPONENT AND TOTAL DELIVERED NOMINAL NATURAL GAS PRICE(SEE NOTE 1)

	****NON-FIRM SERVICE****			PHASE II — FIRM SERVICE				PHASE III — FIRM SERVICE				WEIGHTED AVERAGE — FIRM PRICE				SYSTEM WEIGHTED AVERAGE (NON-FIRM & FIRM) GAS PRICE $/MMBTU
YEAR	NATURAL GAS PRICE $/MMBTU	TRANSPORT COMMODITY $/MMBTU	DELIVERED $/MMBTU	NATURAL GAS PRICE $/MMBTU	TRANSPORTATION COSTS DEMAND $/MMBTU	TRANSPORTATION COSTS COMMODITY $/MMBTU	DELIVERED $/MMBTU	NATURAL GAS PRICE $/MMBTU	TRANSPORTATION COSTS DEMAND $/MMBTU	TRANSPORTATION COSTS COMMODITY $/MMBTU	DELIVERED $/MMBTU	NATURAL GAS PRICE $/MMBTU	TRANSPORTATION COSTS DEMAND $/MMBTU	TRANSPORTATION COSTS COMMODITY $/MMBTU	DELIVERED $/MMBTU	
1994	$2.24	$0.45	$2.69	$1.79	$0.43	$0.06	$2.31	$2.02	$0.75	$0.11	$2.86	$1.79	$0.44	$0.06	$2.31	$2.35
1995	$2.41	$0.45	$2.86	$2.01	$0.43	$0.06	$2.50	$2.41	$0.75	$0.12	$3.26	$2.15	$0.54	$0.06	$2.77	$2.79
1996	$2.61	$0.47	$3.08	$2.61	$0.43	$0.15	$3.20	$2.61	$0.75	$0.13	$3.49	$2.61	$0.55	$0.14	$3.30	$3.28
1997	$2.69	$0.48	$3.16	$2.69	$0.43	$0.16	$3.28	$2.69	$0.75	$0.13	$3.57	$2.69	$0.55	$0.15	$3.38	$3.36
1998	$2.78	$0.49	$3.26	$2.78	$0.42	$0.16	$3.36	$2.78	$0.75	$0.13	$3.66	$2.78	$0.55	$0.15	$3.47	$3.45
1999	$2.88	$0.47	$3.34	$2.88	$0.37	$0.13	$3.38	$2.88	$0.75	$0.14	$3.76	$2.88	$0.51	$0.13	$3.52	$3.51
2000	$2.98	$0.48	$3.46	$2.98	$0.37	$0.13	$3.48	$2.98	$0.75	$0.14	$3.87	$2.98	$0.51	$0.14	$3.63	$3.62
2001	$3.20	$0.50	$3.70	$3.20	$0.37	$0.14	$3.71	$3.20	$0.75	$0.15	$4.10	$3.20	$0.51	$0.14	$3.85	$3.86
2002	$3.45	$0.52	$3.97	$3.45	$0.37	$0.15	$3.97	$3.45	$0.75	$0.16	$4.36	$3.45	$0.51	$0.15	$4.12	$4.11
2003	$3.71	$0.53	$4.24	$3.71	$0.37	$0.16	$4.24	$3.71	$0.75	$0.17	$4.63	$3.71	$0.51	$0.16	$4.39	$4.38
2004	$4.01	$0.54	$4.55	$4.01	$0.37	$0.17	$4.55	$4.01	$0.75	$0.18	$4.94	$4.01	$0.51	$0.17	$4.70	$4.69
2005	$4.34	$0.55	$4.89	$4.34	$0.37	$0.18	$4.89	$4.34	$0.75	$0.19	$5.28	$4.34	$0.51	$0.18	$5.04	$5.03
2006	$4.61	$0.56	$5.17	$4.61	$0.37	$0.19	$5.17	$4.61	$0.75	$0.20	$5.56	$4.61	$0.51	$0.19	$5.32	$5.31
2007	$4.92	$0.57	$5.49	$4.92	$0.37	$0.20	$5.49	$4.92	$0.75	$0.21	$5.88	$4.92	$0.51	$0.20	$5.64	$5.63
2008	$5.25	$0.58	$5.83	$5.25	$0.37	$0.21	$5.83	$5.25	$0.75	$0.22	$6.22	$5.25	$0.51	$0.21	$5.98	$5.97
2009	$5.56	$0.59	$6.15	$5.56	$0.37	$0.22	$6.15	$5.56	$0.75	$0.24	$6.54	$5.56	$0.51	$0.23	$6.30	$6.29
2010	$5.85	$0.60	$6.46	$5.85	$0.37	$0.23	$6.46	$5.85	$0.75	$0.25	$6.85	$5.85	$0.51	$0.24	$6.61	$6.60
2011	$6.16	$0.61	$6.77	$6.16	$0.37	$0.24	$6.77	$6.16	$0.75	$0.26	$7.16	$6.16	$0.51	$0.25	$6.92	$6.91
2012	$6.46	$0.62	$7.08	$6.46	$0.37	$0.25	$7.08	$6.46	$0.75	$0.27	$7.47	$6.46	$0.51	$0.26	$7.23	$7.22
2013	$6.77	$0.64	$7.41	$6.77	$0.37	$0.26	$7.41	$6.77	$0.75	$0.28	$7.80	$6.77	$0.51	$0.27	$7.55	$7.56
2014	$7.06	$0.65	$7.71	$7.06	$0.37	$0.27	$7.71	$7.06	$0.75	$0.29	$8.10	$7.06	$0.51	$0.28	$7.86	$7.85
2015	$7.35	$0.66	$8.01	$7.35	$0.37	$0.28	$8.01	$7.35	$0.75	$0.30	$8.40	$7.35	$0.51	$0.29	$8.16	$8.15
2016	$7.67	$0.67	$8.34	$7.67	$0.37	$0.29	$8.34	$7.67	$0.75	$0.31	$8.73	$7.67	$0.51	$0.30	$8.49	$8.48
2017	$7.98	$0.68	$8.66	$7.98	$0.37	$0.31	$8.66	$7.98	$0.75	$0.33	$9.06	$7.98	$0.51	$0.31	$8.81	$8.80
2018	$8.31	$0.69	$9.00	$8.31	$0.37	$0.32	$9.00	$8.31	$0.75	$0.34	$9.39	$8.31	$0.51	$0.32	$9.15	$9.14
2019	$8.66	$0.70	$9.37	$8.66	$0.37	$0.33	$9.37	$8.66	$0.75	$0.35	$9.76	$8.66	$0.51	$0.34	$9.52	$9.51
2020	$9.01	$0.72	$9.73	$9.01	$0.37	$0.34	$9.73	$9.01	$0.75	$0.36	$10.13	$9.01	$0.51	$0.35	$9.88	$9.87
2021	$9.36	$0.73	$10.11	$9.36	$0.37	$0.36	$10.11	$9.36	$0.75	$0.38	$10.51	$9.36	$0.51	$0.36	$10.26	$10.25
2022	$9.76	$0.74	$10.50	$9.76	$0.37	$0.37	$10.50	$9.76	$0.75	$0.39	$10.90	$9.76	$0.51	$0.38	$10.65	$10.64
2023	$10.15	$0.76	$10.91	$10.15	$0.37	$0.38	$10.91	$10.15	$0.75	$0.41	$11.31	$10.15	$0.51	$0.39	$11.06	$11.05

NOTE 1: DELIVERED NATURAL GAS PRICES ASSUME THAT 100% OF THE PROJECTED FIRM AND NON-FIRM NATURAL GAS AVAILABILITY IS PURCHASED AND FULL TRANSPORATION COSTS ARE INCLUDED. PHASE II AND PHASE III GAS PRICE IS THE WEIGHTED AVERAGE OF THE CONTRACT GAS PRICE AND THE SPOT MARKET GAS PRICE, IF NECESSARY, TO MATCH 100% OF THE FIRM TRANSPORTATION SERVICE. THE 3% GAS TRANSPORTATION CHARGE, IF ASSESSED, IS IN THE COMMODITY CHARGE AND THE GAS INVENTORY CHARGE (GIC), IF ASSESSED, IS IN THE GAS PRICE.

PGBU - BUSINESS SYSTEMS
MARCH, 1994 - EU

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY (SEE NOTE 1)

MARCH, 1994

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II: GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II: (SEE NOTE 2) MAXIMUM	PHASE III: GAS SUPPLY TAKE OR PAY MINIMUM	PHASE III: (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 1994	35	230	255	0	0	290
FEBRUARY	50	230	255	0	0	305
MARCH	75	230	255	0	0	330
APRIL	100	252	280	0	0	380
MAY	0	387	430	0	0	430
JUNE	0	387	430	0	0	430
JULY	0	387	430	0	0	430
AUGUST	0	387	430	0	0	430
SEPTEMBER	0	387	430	0	0	430
OCTOBER	100	252	280	0	0	380
NOVEMBER	75	230	255	0	0	330
DECEMBER	50	230	255	20	45	350
JANUARY 1995	40	230	255	20	45	340
FEBRUARY	55	230	255	20	45	355
MARCH	125	230	255	0	200	580
APRIL	150	252	280	0	200	630
MAY	50	387	430	0	200	680
JUNE	50	387	430	0	200	680
JULY	50	387	430	0	200	680
AUGUST	50	387	430	0	200	680
SEPTEMBER	50	387	430	0	200	680
OCTOBER	150	252	280	0	200	630
NOVEMBER	125	230	255	0	200	580
DECEMBER	95	0	255	0	200	550
JANUARY 1996	45	0	255	0	200	500
FEBRUARY	75	0	255	0	200	530
MARCH	110	0	255	0	200	565
APRIL	130	0	280	0	200	610
MAY	40	0	430	0	200	670
JUNE	40	0	430	0	200	670
JULY	40	0	430	0	200	670
AUGUST	40	0	430	0	200	670
SEPTEMBER	40	0	430	0	200	670
OCTOBER	130	0	280	0	200	610
NOVEMBER	110	0	255	0	200	565
DECEMBER	75	0	255	0	200	530
JANUARY 1997	35	0	255	0	200	490
FEBRUARY	65	0	255	0	200	520
MARCH	100	0	255	0	200	555
APRIL	120	0	280	0	200	600
MAY	30	0	430	0	200	660
JUNE	30	0	430	0	200	660
JULY	30	0	430	0	200	660
AUGUST	30	0	430	0	200	660
SEPTEMBER	30	0	430	0	200	660
OCTOBER	120	0	280	0	200	600
NOVEMBER	100	0	255	0	200	555
DECEMBER	65	0	255	0	200	520
1994	40	299	332	2	4	378
1995	83	280	332	3	174	589
1996	73	0	332	0	200	605
1997	63	0	332	0	200	595

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II: GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II: (SEE NOTE 2) MAXIMUM	PHASE III: GAS SUPPLY TAKE OR PAY MINIMUM	PHASE III: (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 1998	25	0	255	0	200	480
FEBRUARY	55	0	255	0	200	510
MARCH	90	0	255	0	200	545
APRIL	110	0	280	0	200	590
MAY	20	0	430	0	200	650
JUNE	20	0	430	0	200	650
JULY	20	0	430	0	200	650
AUGUST	20	0	430	0	200	650
SEPTEMBER	20	0	430	0	200	650
OCTOBER	110	0	280	0	200	590
NOVEMBER	90	0	255	0	200	545
DECEMBER	55	0	255	0	200	510
JANUARY 1999	15	0	255	0	200	470
FEBRUARY	45	0	255	0	200	500
MARCH	80	0	255	0	200	535
APRIL	100	0	280	0	200	580
MAY	10	0	430	0	200	640
JUNE	10	0	430	0	200	640
JULY	10	0	430	0	200	640
AUGUST	10	0	430	0	200	640
SEPTEMBER	10	0	430	0	200	640
OCTOBER	100	0	280	0	200	580
NOVEMBER	80	0	255	0	200	535
DECEMBER	45	0	255	0	200	500
JANUARY 2000	5	0	255	0	200	460
FEBRUARY	35	0	255	0	200	490
MARCH	70	0	255	0	200	525
APRIL	90	0	280	0	200	570
MAY	0	0	430	0	200	630
JUNE	0	0	430	0	200	630
JULY	0	0	430	0	200	630
AUGUST	0	0	430	0	200	630
SEPTEMBER	0	0	430	0	200	630
OCTOBER	90	0	280	0	200	570
NOVEMBER	70	0	255	0	200	525
DECEMBER	35	0	255	0	200	490
JANUARY 2001	0	0	255	0	200	455
FEBRUARY	15	0	255	0	200	470
MARCH	50	0	255	0	200	505
APRIL	70	0	280	0	200	550
MAY	0	0	430	0	200	630
JUNE	0	0	430	0	200	630
JULY	0	0	430	0	200	630
AUGUST	0	0	430	0	200	630
SEPTEMBER	0	0	430	0	200	630
OCTOBER	70	0	280	0	200	550
NOVEMBER	50	0	255	0	200	505
DECEMBER	15	0	255	0	200	470
1998	53	0	332	0	200	585
1999	43	0	332	0	200	575
2000	33	0	332	0	200	565
2001	23	0	332	0	200	555

NOTE 1: FOR YEARS 2002 THROUGH 2023, MONTHLY NON-FIRM AND FIRM AVAILABILITIES WILL EQUAL THE CORRESPONDING MONTHLY AVAILABILITIES IN 2001.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM DECEMBER, 1995 FORWARD, ASSUME THAT UP TO THE PHASE II VOLUMES WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES ASSUME 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE (i.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II FIRM TRANSPORTATION SERVICE FPL WILL COMMIT TO. THEREAFTER, THE NEW FIRM TRANSPORTATION COMMITMENT WILL BECOME A SUNK COST.

NOTE 3: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1998 THROUGH FEBRUARY, 2000, ASSUME THAT UP TO THE PHASE III VOLUMES WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2000 FORWARD, ASSUME THAT UP TO THE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (i.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATION SERVICE FPL WILL COMMIT TO. THEREAFTER, THE NEW FIRM TRANSPORTATION COMMITMENT WILL BECOME A SUNK COST.

PGBU - BUSINESS SYSTEMS
MARCH, 1994 - EU

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL PRICES TO SCHERER UNIT 4 & THE MARTIN SITE

MARCH 1994

FORECAST ASSUMES THAT THE MARTIN COAL PLANT WILL STARTUP IN 2001

YEAR	PLANT SCHERER UNIT 4 WEIGHTED AVERAGE NOMINAL $/TON	PLANT SCHERER UNIT 4 WEIGHTED AVERAGE NOMINAL $/MMBTU	PLANT SCHERER UNIT 4 SPOT PRICE NOMINAL $/TON	PLANT SCHERER UNIT 4 SPOT PRICE NOMINAL $/MMBTU
1994	$33.52	$1.74	$25.11	$1.46
1995	$32.20	$1.70	$25.76	$1.48
1996	$32.92	$1.73	$26.11	$1.49
1997	$34.03	$1.77	$26.47	$1.56
1998	$34.58	$1.80	$27.98	$1.65
1999	$34.57	$1.84	$28.63	$1.68
2000	$35.44	$1.89	$29.35	$1.73
2001	$35.28	$1.92	$30.12	$1.77
2002	$36.21	$1.97	$30.92	$1.82
2003	$37.20	$2.02	$31.81	$1.87
2004	$38.54	$2.09	$32.73	$1.93
2005	$39.65	$2.15	$33.71	$1.98
2006	$40.80	$2.22	$34.70	$2.04
2007	$42.01	$2.28	$35.75	$2.10
2008	$43.23	$2.35	$36.78	$2.16
2009	$37.84	$2.23	$37.84	$2.23
2010	$38.91	$2.29	$38.94	$2.29
2011	$40.00	$2.35	$40.06	$2.36
2012	$41.11	$2.42	$41.22	$2.42
2013	$42.27	$2.49	$42.42	$2.50
2014	$43.71	$2.57	$43.71	$2.57
2015	$44.98	$2.65	$45.04	$2.65
2016	$46.29	$2.72	$46.42	$2.73
2017	$47.66	$2.80	$47.88	$2.82
2018	$49.07	$2.89	$49.39	$2.91
2019	$50.93	$3.00	$50.93	$3.00
2020	$52.44	$3.08	$52.53	$3.09
2021	$54.00	$3.18	$54.19	$3.19
2022	$55.61	$3.27	$55.92	$3.29
2023	$57.28	$3.37	$57.70	$3.39

YEAR	MARTIN PLANT: LOW SULFUR COAL WEIGHTED AVERAGE NOMINAL $/TON	MARTIN PLANT: LOW SULFUR COAL WEIGHTED AVERAGE NOMINAL $/MMBTU	MARTIN PLANT: LOW SULFUR COAL SPOT PRICE NOMINAL $/TON	MARTIN PLANT: LOW SULFUR COAL SPOT PRICE NOMINAL $/MMBTU	MARTIN PLANT: HIGH SULFUR COAL WEIGHTED AVERAGE NOMINAL $/TON	MARTIN PLANT: HIGH SULFUR COAL WEIGHTED AVERAGE NOMINAL $/MMBTU	MARTIN PLANT: HIGH SULFUR COAL SPOT PRICE NOMINAL $/TON	MARTIN PLANT: HIGH SULFUR COAL SPOT PRICE NOMINAL $/MMBTU
1994	$40.73	$1.67	$40.73	$1.67	$40.01	$1.74	$40.01	$1.74
1995	$42.07	$1.72	$42.07	$1.72	$40.28	$1.75	$40.28	$1.75
1996	$43.67	$1.79	$43.67	$1.79	$40.83	$1.78	$40.83	$1.78
1997	$45.02	$1.84	$45.02	$1.84	$41.79	$1.82	$41.79	$1.82
1998	$46.30	$1.90	$46.30	$1.90	$42.81	$1.86	$42.81	$1.86
1999	$47.57	$1.95	$47.57	$1.95	$43.97	$1.91	$43.97	$1.91
2000	$48.85	$2.00	$48.91	$2.00	$45.24	$1.97	$45.50	$1.98
2001	$50.27	$2.06	$50.49	$2.07	$46.60	$2.03	$47.12	$2.05
2002	$51.78	$2.12	$52.21	$2.14	$48.02	$2.09	$48.79	$2.12
2003	$53.38	$2.19	$54.00	$2.21	$49.57	$2.16	$50.71	$2.20
2004	$55.90	$2.29	$55.94	$2.29	$52.65	$2.29	$52.69	$2.29
2005	$57.72	$2.37	$57.97	$2.33	$54.41	$2.37	$54.76	$2.38
2006	$59.62	$2.44	$60.05	$2.46	$56.27	$2.45	$56.96	$2.48
2007	$61.58	$2.52	$62.19	$2.55	$58.16	$2.53	$59.15	$2.57
2008	$63.55	$2.60	$64.32	$2.64	$60.10	$2.61	$61.44	$2.67
2009	$66.36	$2.72	$66.46	$2.72	$63.67	$2.77	$63.77	$2.77
2010	$68.48	$2.81	$68.70	$2.82	$65.78	$2.86	$66.16	$2.88
2011	$70.67	$2.90	$71.10	$2.91	$67.93	$2.95	$68.64	$2.98
2012	$72.99	$2.99	$73.79	$3.02	$70.14	$3.05	$71.15	$3.09
2013	$75.48	$3.09	$76.83	$3.15	$72.43	$3.15	$73.77	$3.21
2014	$80.14	$3.28	$80.30	$3.29	$76.37	$3.32	$76.53	$3.33
2015	$82.99	$3.40	$83.93	$3.44	$78.91	$3.43	$79.41	$3.45
2016	$86.02	$3.53	$87.92	$3.60	$81.56	$3.55	$82.42	$3.58
2017	$89.16	$3.65	$92.02	$3.77	$84.33	$3.67	$85.58	$3.72
2018	$92.39	$3.79	$96.27	$3.95	$87.17	$3.79	$88.85	$3.86
2019	$100.36	$4.11	$100.60	$4.12	$91.99	$4.00	$92.24	$4.01
2020	$103.95	$4.26	$105.12	$4.31	$95.09	$4.13	$95.76	$4.16
2021	$107.62	$4.41	$109.70	$4.50	$98.30	$4.27	$99.42	$4.32
2022	$111.40	$4.57	$114.34	$4.69	$101.64	$4.42	$103.27	$4.49
2023	$115.33	$4.73	$119.19	$4.88	$105.10	$4.57	$107.24	$4.66

PGBU -BUSINESS SYSTEMS
MARCH, 1994 - EU

1994 TO 2023 FPL SHORT-TERM/DRI LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL TO SJRPP, ORIMULSION & PETROLEUM COKE PRICES

MARCH 1994

YEAR	(SEE NOTE 1) DELIVERED ST. JOHNS RIVER POWER PARK COAL PRICES — CONTRACT PRICE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		(SEE NOTE 2) ORIMULSION DELIVERED NOMINAL DOLLARS		PETROLEUM COKE DELIVERED NOMINAL
	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	BASE PRICE $/MMBTU	EXCESS PRICE $/MMBTU	$/MMBTU
1994	$41.37	$1.69	$29.76	$1.25	$38.39	$1.58	$1.76	$1.08	$0.90
1995	$40.98	$1.68	$31.94	$1.31	$38.38	$1.57	$1.75	$1.14	$0.92
1996	$41.83	$1.72	$32.96	$1.35	$39.10	$1.60	$1.79	$1.17	$0.95
1997	$41.30	$1.68	$30.85	$1.34	$36.82	$1.54	$1.76	$1.17	$0.99
1998	$39.39	$1.60	$31.65	$1.38	$37.07	$1.53	$1.67	$1.20	$1.01
1999	$39.98	$1.61	$32.56	$1.42	$37.75	$1.56	$1.69	$1.24	$1.04
2000	$41.07	$1.66	$33.79	$1.47	$38.89	$1.60	$1.74	$1.29	$1.07
2001	$42.26	$1.71	$35.09	$1.53	$40.11	$1.65	$1.79	$1.34	$1.10
2002	$39.96	$1.64	$37.93	$1.65	$39.35	$1.64	$1.72	$1.45	$1.14
2003	$39.45	$1.72	$39.48	$1.72	$39.46	$1.72	$1.80	$1.51	$1.18
2004	$40.65	$1.77	$41.08	$1.79	$40.78	$1.77	$1.86	$1.58	$1.22
2005	$41.92	$1.82	$42.75	$1.86	$42.17	$1.83	$1.91	$1.65	$1.26
2006	$43.25	$1.88	$44.52	$1.94	$43.63	$1.90	$1.97	$1.72	$1.30
2007	$44.62	$1.94	$46.28	$2.01	$45.12	$1.96	$2.04	$1.79	$1.36
2008	$48.05	$2.09	$48.12	$2.09	$48.07	$2.09	$2.19	$1.86	$1.41
2009	$49.54	$2.15	$52.77	$2.16	$50.51	$2.16	$2.25	$1.93	$1.45
2010	$51.09	$2.22	$54.57	$2.24	$52.14	$2.23	$2.32	$2.00	$1.50
2011	$52.67	$2.29	$56.51	$2.32	$53.82	$2.30	$2.39	$2.07	$1.55
2012	$54.29	$2.36	$58.70	$2.41	$55.61	$2.37	$2.47	$2.16	$1.62
2013	$61.72	$2.53	$61.20	$2.51	$61.56	$2.52	$2.64	$2.25	$1.67
2014	$63.65	$2.61	$60.26	$2.62	$62.63	$2.61	$2.72	$2.35	$1.73
2015	$65.66	$2.69	$62.57	$2.72	$64.74	$2.70	$2.81	$2.45	$1.79
2016	$67.75	$2.78	$65.00	$2.83	$66.92	$2.79	$2.90	$2.55	$1.86
2017	$69.92	$2.87	$67.54	$2.94	$69.21	$2.89	$2.99	$2.65	$2.02
2018	$70.00	$3.04	$70.18	$3.05	$70.05	$3.05	$3.17	$2.76	$2.09
2019	$72.21	$3.14	$72.91	$3.17	$72.42	$3.15	$3.27	$2.87	$2.16
2020	$74.51	$3.24	$75.75	$3.29	$74.88	$3.26	$3.37	$2.98	$2.24
2021	$76.88	$3.34	$78.71	$3.42	$77.43	$3.37	$3.48	$3.10	$2.32
2022	$79.35	$3.45	$81.81	$3.56	$80.09	$3.48	$3.59	$3.23	$2.51
2023	$84.78	$3.69	$85.02	$3.70	$84.85	$3.69	$3.83	$3.36	$2.59

NOTE 1: ST. JOHNS RIVER POWER PARK PRICES INCLUDE VARIABLE O & M COSTS.
NOTE 2: ORIMULSION PRICES DOES NOT INCLUDE ANY O & M COSTS

PGBU-BUSINESS SYSTEMS
MARCH, 1994 - EU

Inter-Office Correspondence

FPL

TO: Distribution

DATE: March 31, 1995

LOCATION: QRA/JB

FROM: R. Silva
E. Ungar
J. Wehner

SUBJECT: FPL Long-Term (1995-2024) Base Case Fossil Fuel Price & Natural Gas Availability Forecast

Attached is the updated FPL long-term base case fossil fuel price forecast for crude oil, residual and distillate fuel oil, natural gas, coal, Orimulsion, and petroleum coke, as well as projected availability of natural gas to FPL.

The forecast methodology, underlying assumptions and resulting forecast values were developed jointly by PGBU Business Systems and QRA. This forecast supersedes the March 31, 1994 FPL short-term/DRI long-term forecast and should be used in the 1995 Integrated Resource Planning process and all other long-term analyses for the 1995 to 2024 period.

The following describes the most significant changes between this and last year's forecast:

- o Lower than previously projected crude oil prices linked to lower anticipated finding costs. As a result, the 2005 delivered nominal price of low and high sulfur residual fuel oil is about 16% lower than last year's forecast

- o More optimistic assessment of the level of natural gas supply based on assumed advances in drilling technology and analysis of seismic data, and greater competition from lower priced residual fuel oil and coal. As a result, the 2005 delivered natural gas price forecast is approximately 18% lower than last year's forecast

- o The projected delivered nominal price of coal, Orimulsion and petroleum coke is essentially unchanged from last year's forecast.

If you have any questions concerning the new forecast methodology and underlying assumptions supporting the forecast please contact Eugene Ungar at 552-3412 or John Wehner at 694-3411.

R. Silva | E. Ungar | J. C. Wehner

foredist

EU/JW
Attachments

Distribution: (Residual fuel and natural gas graphs only)

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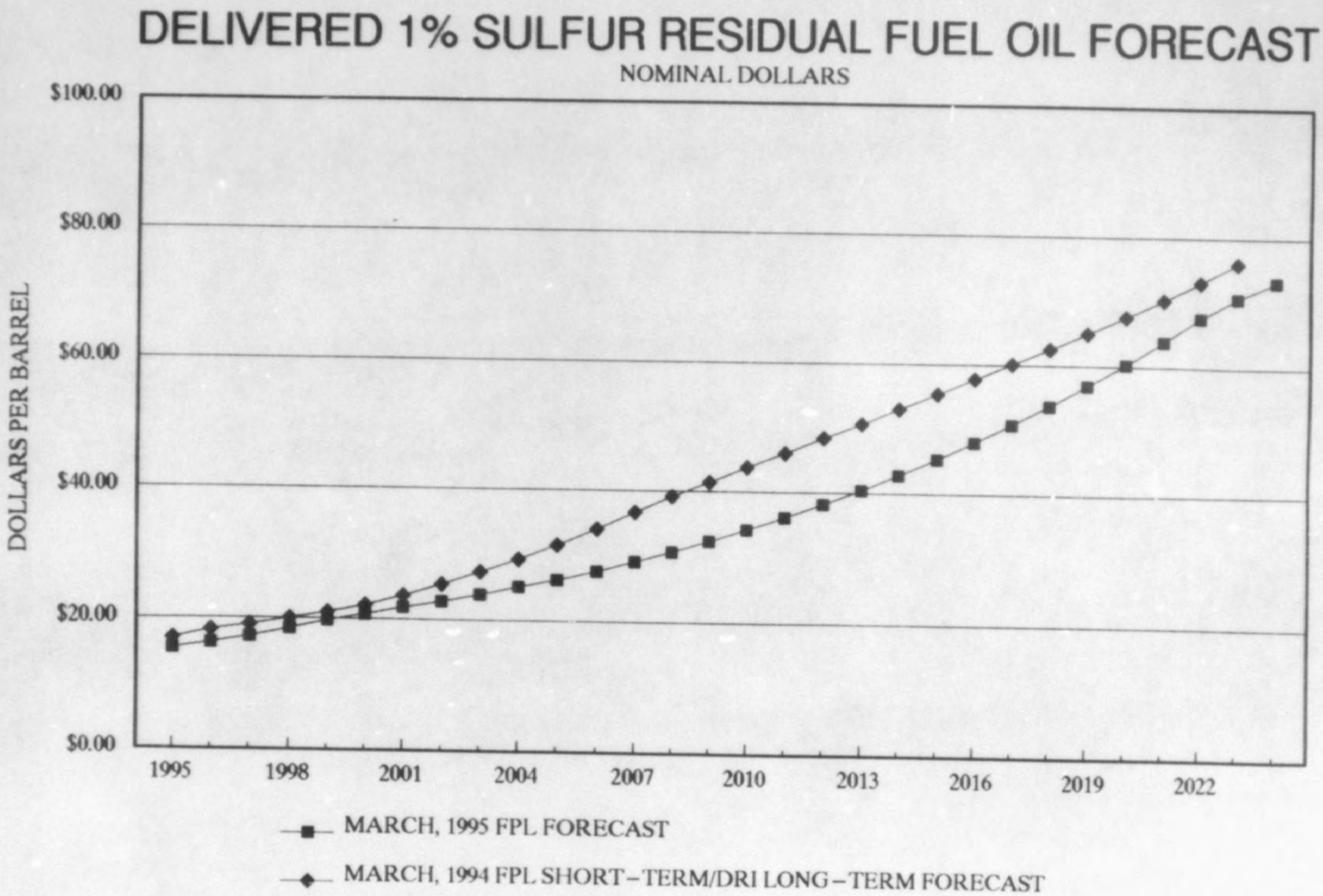
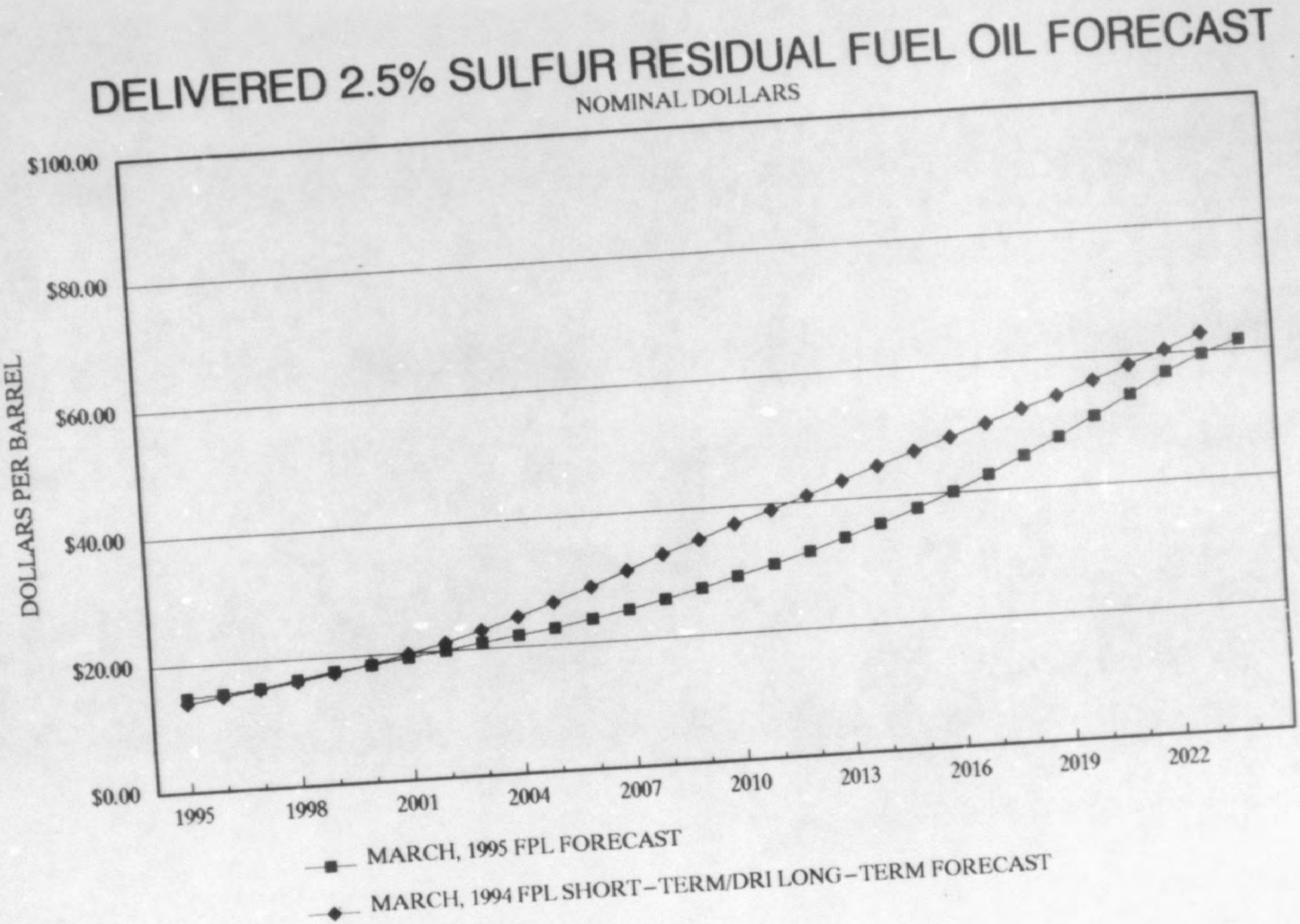
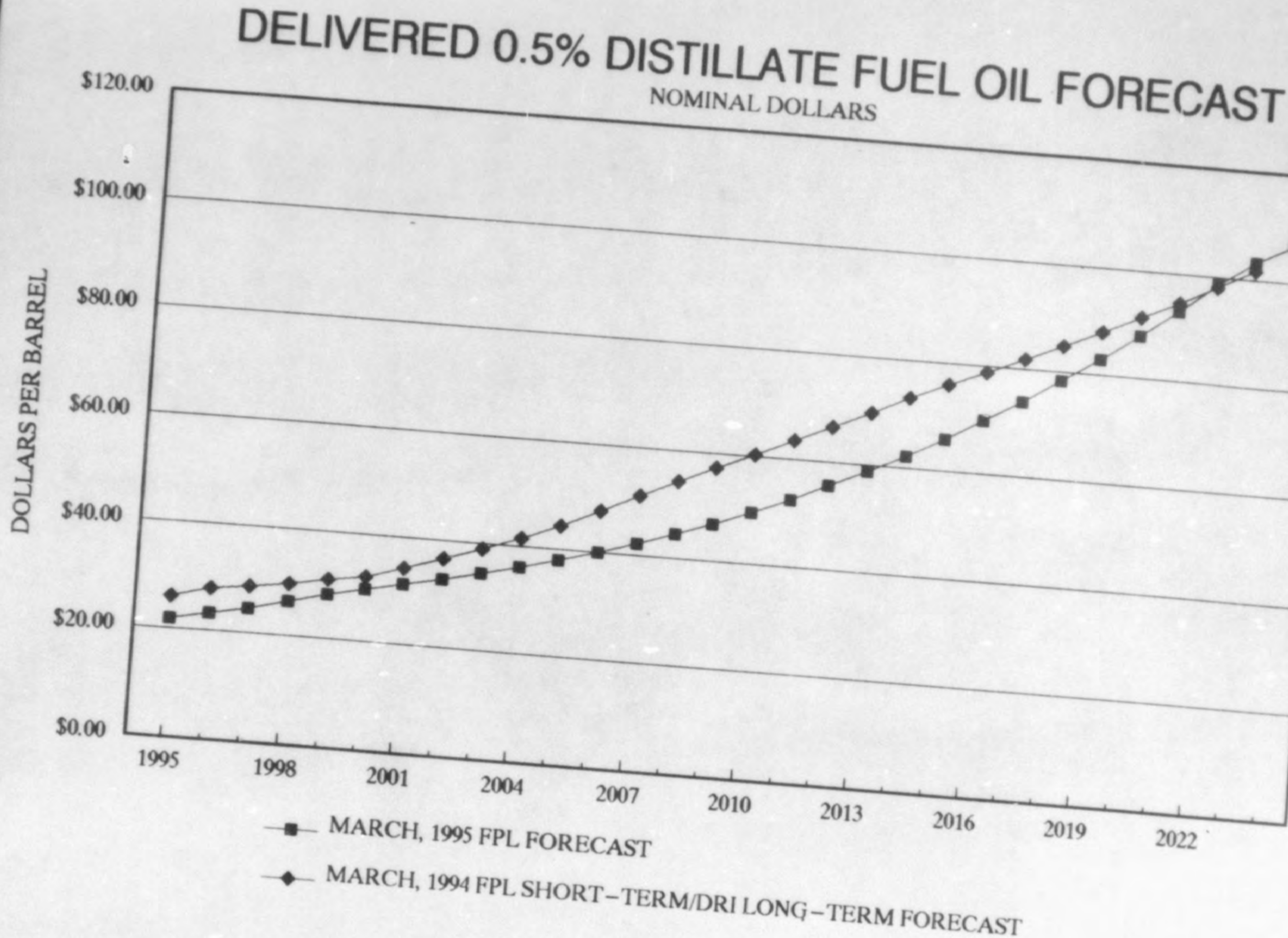
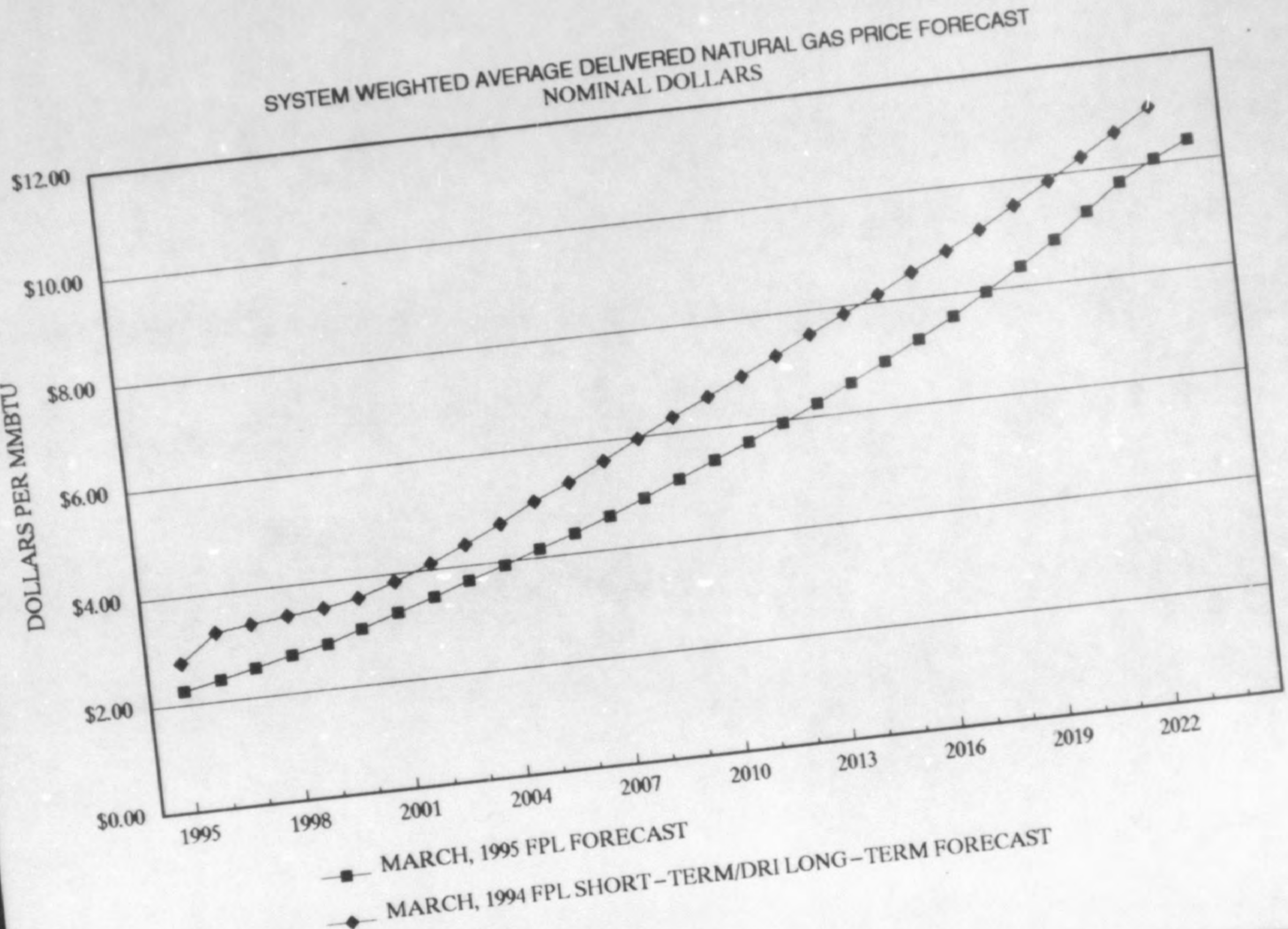
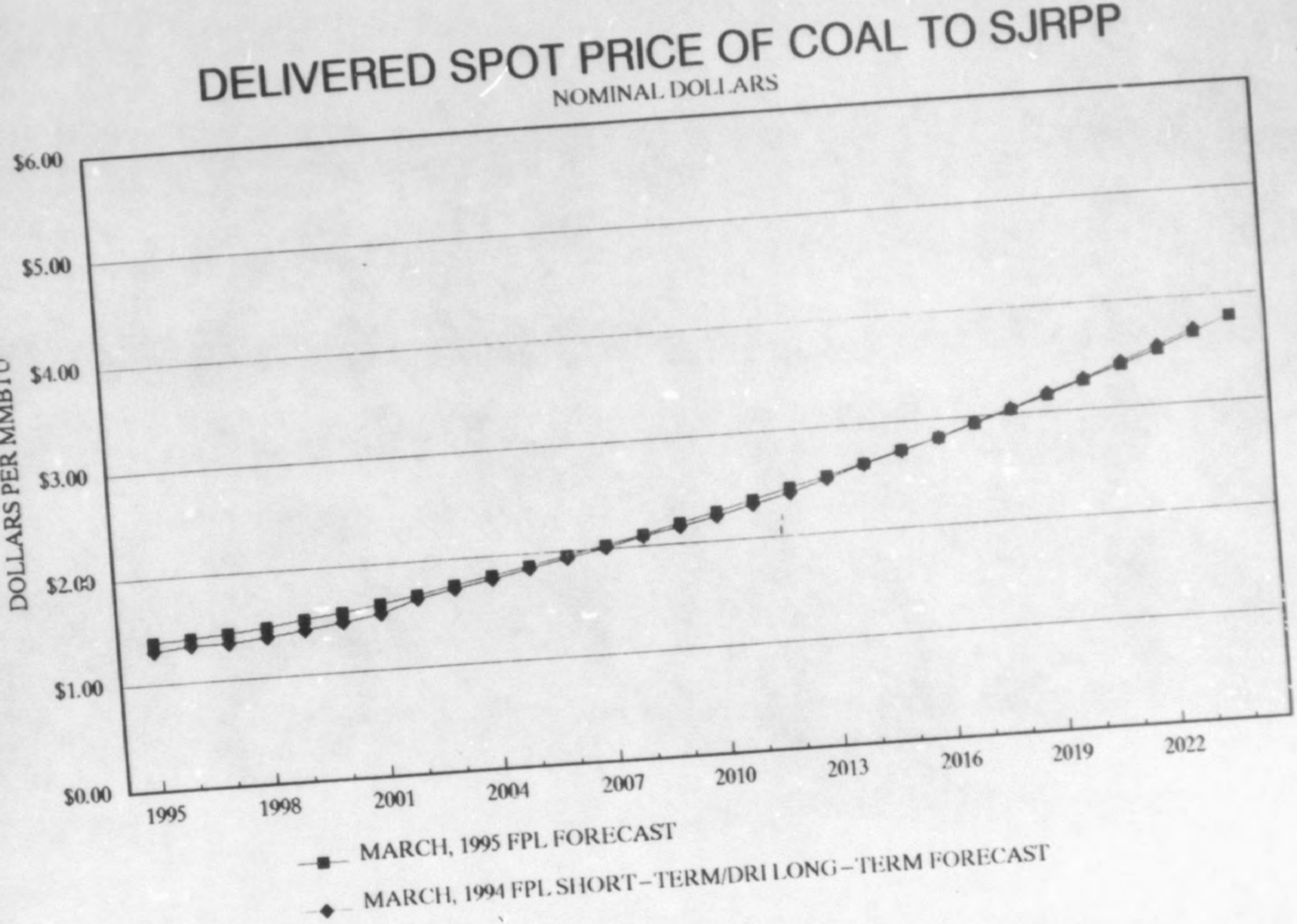

DELIVERED 1% SULFUR RESIDUAL FUEL OIL FORECAST
NOMINAL DOLLARS
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
DOLLARS PER BARREL
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT–TERM/DRI LONG–TERM FORECAST

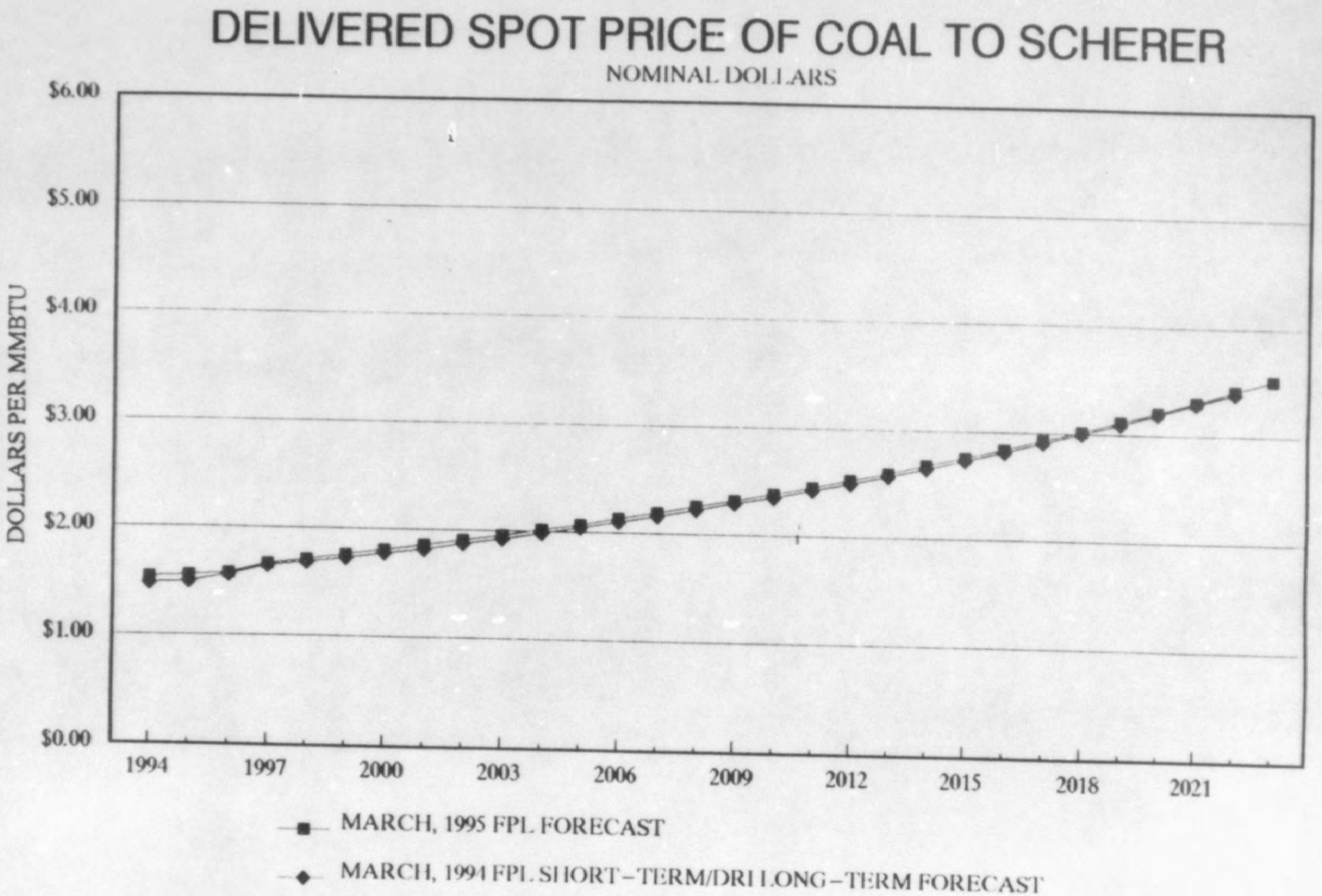

DELIVERED 2.5% SULFUR RESIDUAL FUEL OIL FORECAST
NOMINAL DOLLARS
DOLLARS PER BARREL
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT–TERM/DRI LONG–TERM FORECAST

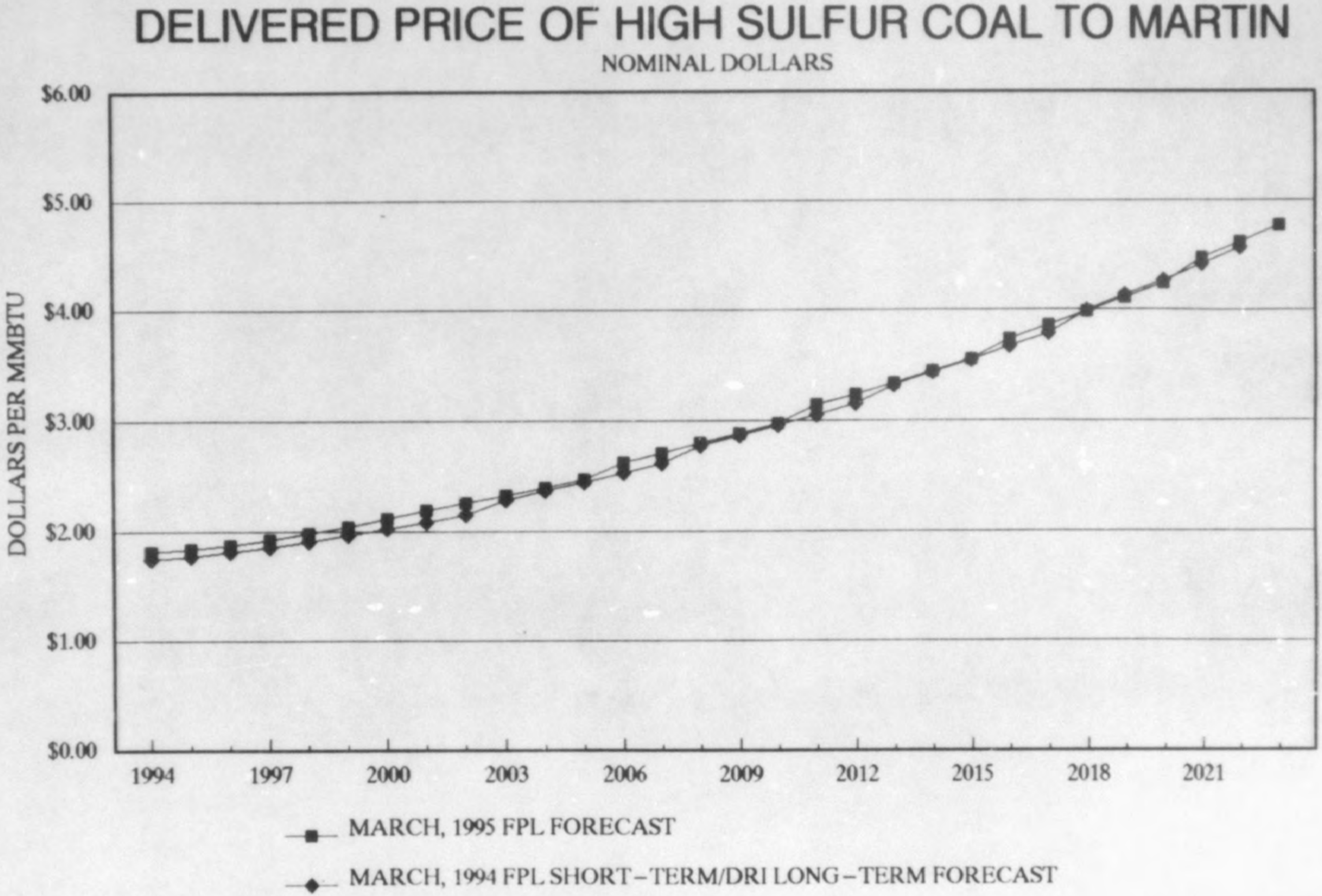

DELIVERED 0.5% DISTILLATE FUEL OIL FORECAST
NOMINAL DOLLARS
DOLLARS PER BARREL
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$0.00
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT-TERM/DRI LONG-TERM FORECAST



SYSTEM WEIGHTED AVERAGE DELIVERED NATURAL GAS PRICE FORECAST
NOMINAL DOLLARS
DOLLARS PER MMBTU
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT-TERM/DRI LONG-TERM FORECAST

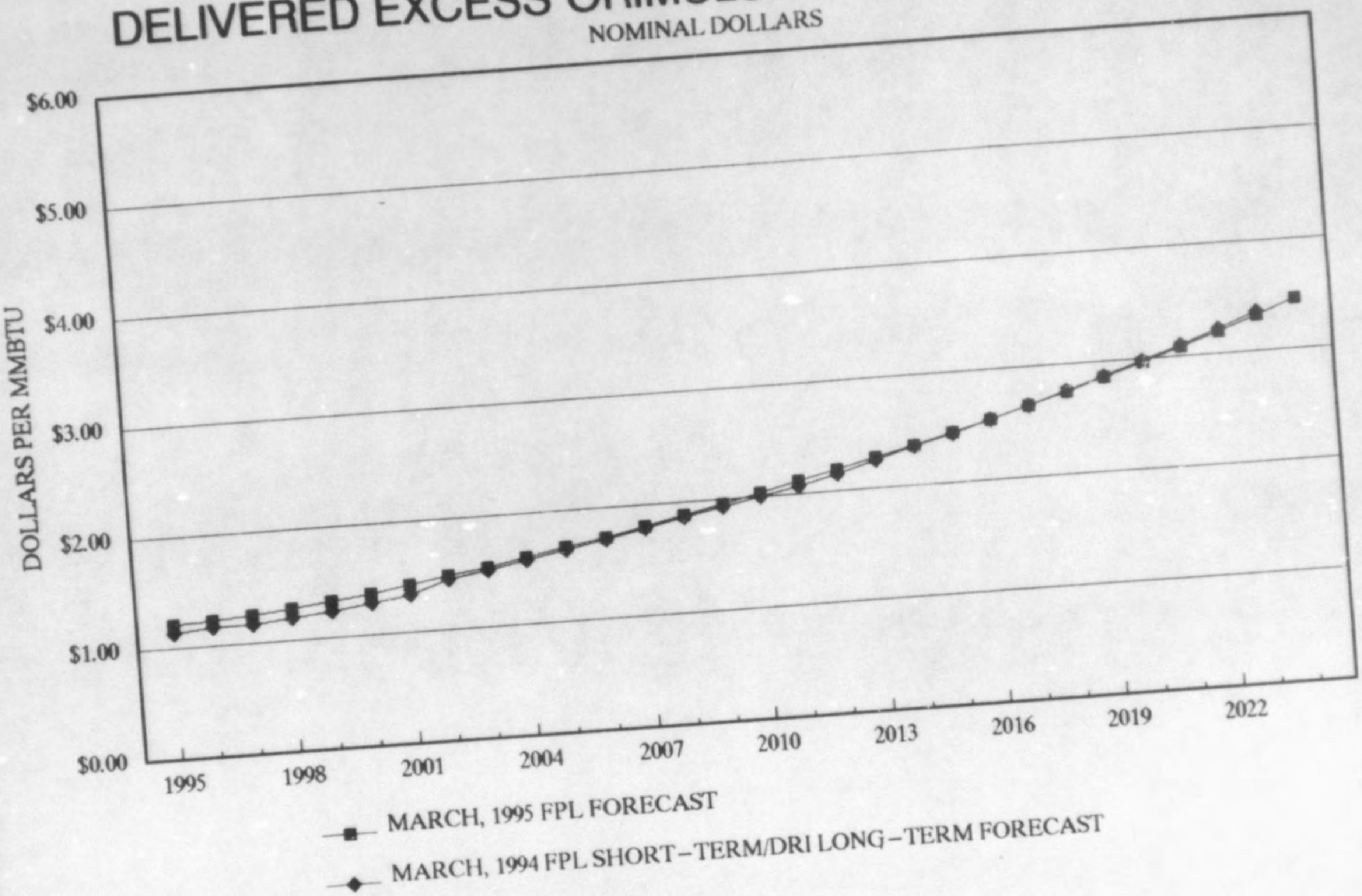

DELIVERED SPOT PRICE OF COAL TO SJRPP
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT–TERM/DRI LONG–TERM FORECAST


DELIVERED SPOT PRICE OF COAL TO SCHERER
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1994
1997
2000
2003
2006
2009
2012
2015
2018
2021
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT-TERM/DRI LONG-TERM FORECAST



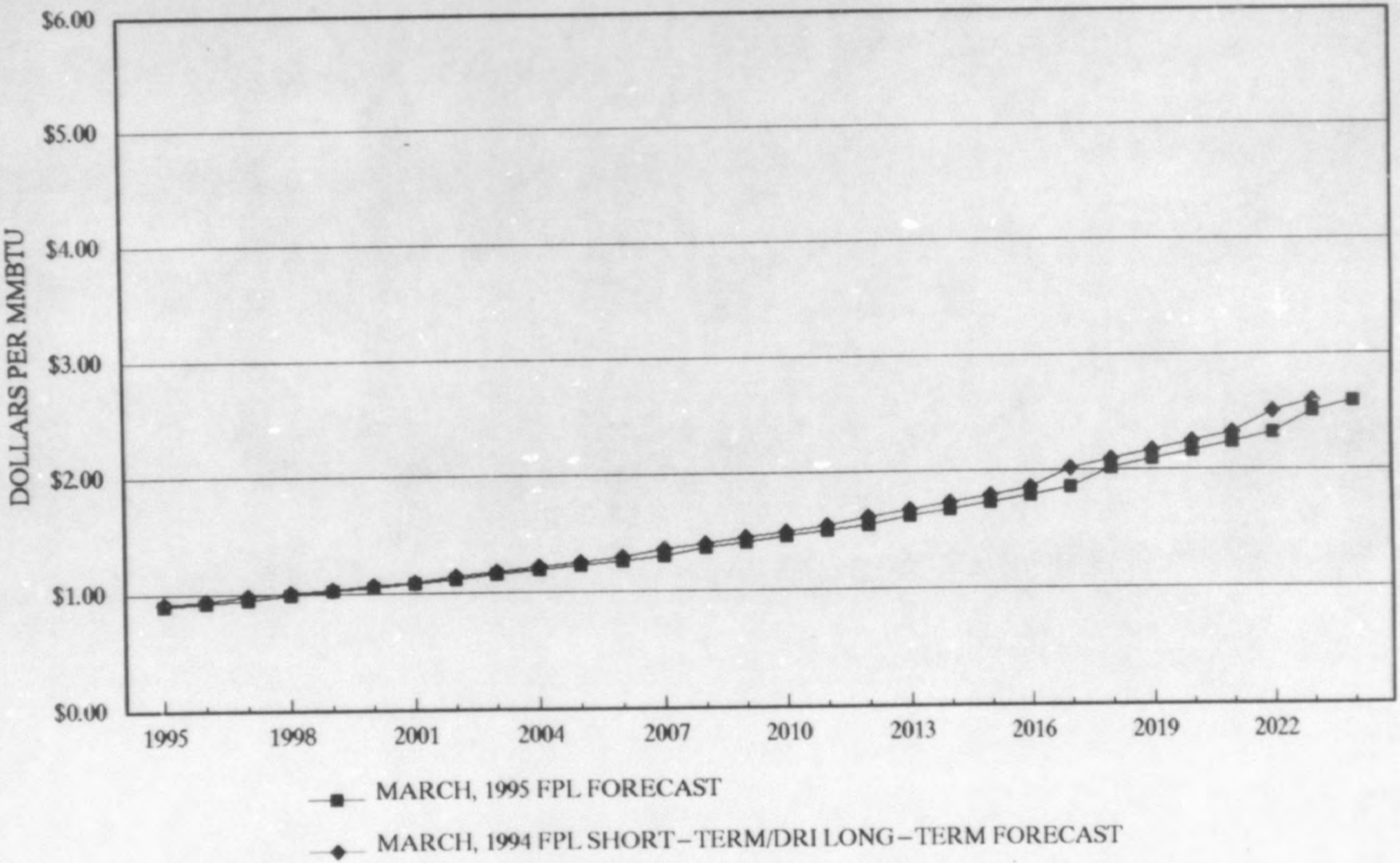
DELIVERED PRICE OF HIGH SULFUR COAL TO MARTIN
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1994
1997
2000
2003
2006
2009
2012
2015
2018
2021
MARCH, 1995 FPL FORECAST
MARCH, 1994 FPL SHORT-TERM/DRI LONG-TERM FORECAST

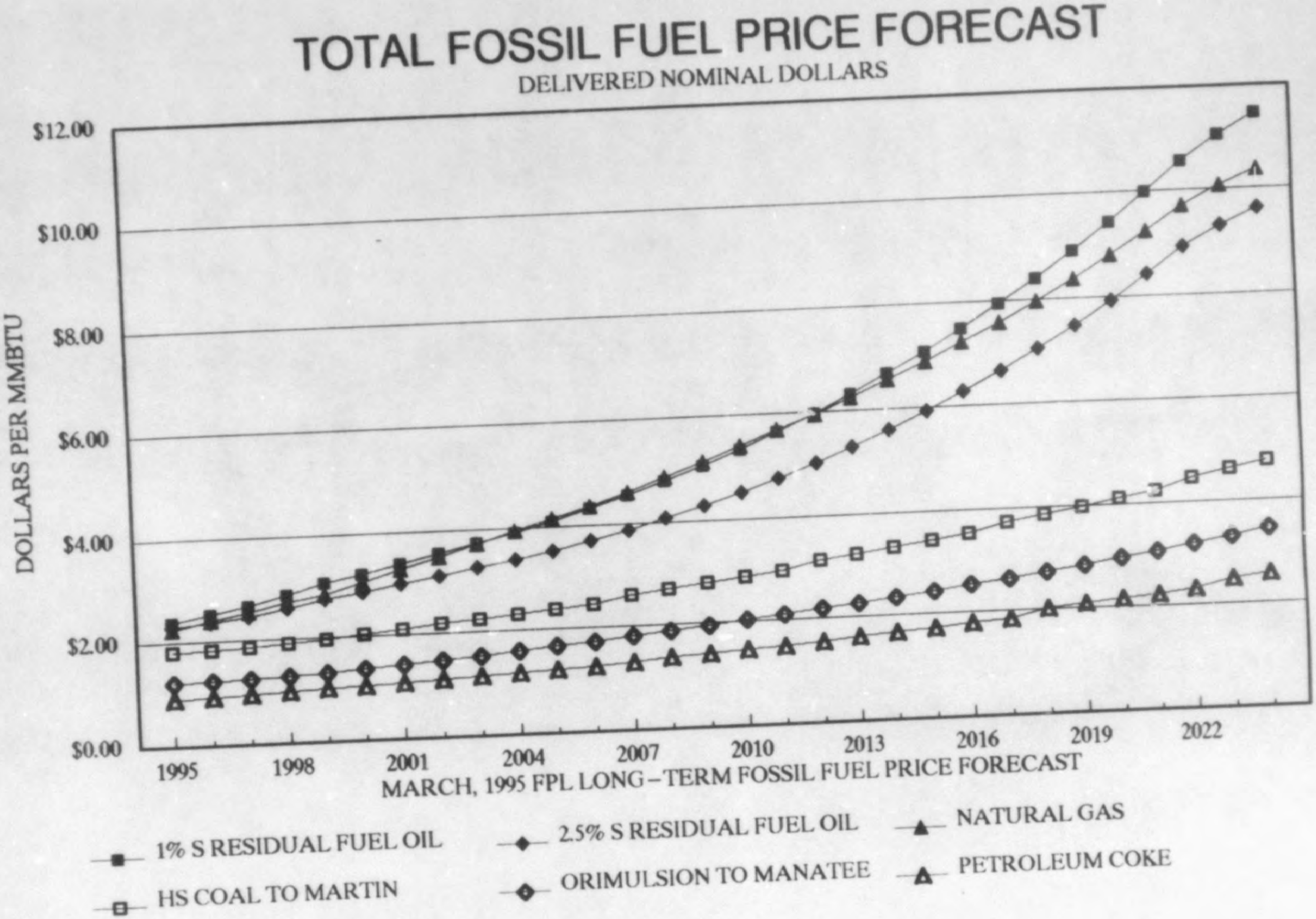
DELIVERED EXCESS ORIMULSION PRICE TO MANATEE



DELIVERED PETROLEUM COKE PRICE FORECAST

NOMINAL DOLLARS




TOTAL FOSSIL FUEL PRICE FORECAST
DELIVERED NOMINAL DOLLARS
DOLLARS PER MMBTU
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
1995
1998
2001
2004
2007
2010
2013
2016
2019
2022
MARCH, 1995 FPL LONG-TERM FOSSIL FUEL PRICE FORECAST
1% S RESIDUAL FUEL OIL
2.5% S RESIDUAL FUEL OIL
NATURAL GAS
HS COAL TO MARTIN
ORIMULSION TO MANATEE
PETROLEUM COKE

1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

NOMINAL DOLLAR CRUDE OIL, DELIVERED DISTILLATE (NO. 2) & U.S.G.C. RESIDUAL & DISTILLATE FUEL OIL PRICES

MARCH 1995

	*******NOMINAL CRUDE OIL PRICES********			
	ARABIAN LIGHT		****WEST TEXAS***** ***INTERMEDIATE****	
YEAR	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1995	$15.80	$2.71	$18.81	$3.23
1996	$16.72	$2.87	$19.72	$3.38
1997	$17.68	$3.03	$20.68	$3.55
1998	$18.99	$3.26	$21.98	$3.77
1999	$20.38	$3.50	$23.38	$4.01
2000	$21.36	$3.66	$24.62	$4.22
2001	$22.41	$3.84	$25.92	$4.45
2002	$23.48	$4.03	$27.23	$4.67
2003	$24.58	$4.22	$28.63	$4.91
2004	$25.74	$4.41	$30.06	$5.16
2005	$26.89	$4.61	$31.54	$5.41
2006	$28.26	$4.85	$33.24	$5.70
2007	$29.67	$5.09	$35.03	$6.01
2008	$31.21	$5.35	$36.92	$6.33
2009	$32.87	$5.64	$38.91	$6.67
2010	$34.65	$5.94	$41.01	$7.03
2011	$36.51	$6.26	$43.22	$7.41
2012	$38.54	$6.61	$45.56	$7.81
2013	$40.66	$6.97	$48.01	$8.23
2014	$42.91	$7.36	$50.60	$8.68
2015	$45.33	$7.78	$53.33	$9.15
2016	$47.89	$8.21	$56.21	$9.64
2017	$50.60	$8.68	$59.24	$10.16
2018	$53.44	$9.17	$62.44	$10.71
2019	$56.46	$9.69	$65.81	$11.29
2020	$59.67	$10.23	$69.35	$11.90
2021	$63.04	$10.81	$73.10	$12.54
2022	$66.60	$11.42	$77.04	$13.21
2023	$69.43	$11.91	$80.25	$13.77
2024	$71.68	$12.30	$82.87	$14.21

	(SEE NOTE 1) *****0.5% SULFUR****** **DISTILLATE FUEL OIL** DELIVERED NOMINAL		(SEE NOTE 2) *****0.3% SULFUR****** **DISTILLATE FUEL OIL* DELIVERED NOMINAL		******PLATT'S LOW POSTING @ USGC******			
					****1.0% SULFUR**** **RESIDUAL FUEL OIL* NOMINAL @ USGC		****3.0% SULFUR**** *RESIDUAL FUEL OIL* NOMINAL @ USGC	
YEAR	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1995	$21.91	$3.76	$23.60	$4.05	$13.96	$2.18	$13.18	$2.06
1996	$23.19	$3.98	$25.03	$4.29	$14.82	$2.32	$13.55	$2.12
1997	$24.54	$4.21	$26.57	$4.56	$15.73	$2.46	$13.99	$2.19
1998	$26.36	$4.52	$28.60	$4.91	$16.96	$2.65	$14.77	$2.31
1999	$28.31	$4.86	$30.81	$5.29	$18.27	$2.86	$15.67	$2.45
2000	$29.71	$5.10	$32.65	$5.60	$19.22	$3.00	$16.23	$2.54
2001	$31.27	$5.36	$34.60	$5.93	$20.24	$3.16	$16.91	$2.64
2002	$32.86	$5.64	$36.61	$6.28	$21.28	$3.33	$17.59	$2.75
2003	$34.51	$5.92	$38.76	$6.65	$22.37	$3.49	$18.30	$2.86
2004	$36.23	$6.22	$40.94	$7.02	$23.50	$3.67	$19.04	$2.97
2005	$37.98	$6.51	$43.21	$7.41	$24.65	$3.85	$19.77	$3.09
2006	$40.02	$6.87	$45.67	$7.83	$26.00	$4.06	$20.67	$3.23
2007	$42.15	$7.23	$48.21	$8.27	$27.40	$4.28	$21.67	$3.39
2008	$44.47	$7.63	$50.96	$8.74	$28.92	$4.52	$22.77	$3.56
2009	$46.96	$8.06	$53.84	$9.23	$30.56	$4.78	$23.96	$3.74
2010	$49.65	$8.52	$56.93	$9.76	$32.33	$5.05	$25.27	$3.95
2011	$52.46	$9.00	$60.11	$10.31	$34.19	$5.34	$26.63	$4.16
2012	$55.54	$9.53	$63.57	$10.90	$36.23	$5.66	$28.16	$4.40
2013	$58.75	$10.08	$67.18	$11.52	$38.35	$5.99	$29.74	$4.65
2014	$62.18	$10.67	$71.05	$12.19	$40.62	$6.35	$31.45	$4.91
2015	$65.87	$11.30	$75.21	$12.90	$43.06	$6.73	$33.31	$5.20
2016	$69.78	$11.97	$79.57	$13.65	$45.65	$7.13	$35.27	$5.51
2017	$73.94	$12.68	$84.21	$14.44	$48.40	$7.56	$37.47	$5.85
2018	$78.32	$13.43	$89.10	$15.28	$51.30	$8.02	$39.79	$6.22
2019	$82.98	$14.23	$94.26	$16.17	$54.39	$8.50	$42.27	$6.60
2020	$87.94	$15.08	$99.73	$17.11	$57.68	$9.01	$44.92	$7.02
2021	$93.18	$15.98	$105.54	$18.10	$61.15	$9.55	$47.73	$7.46
2022	$98.71	$16.93	$111.68	$19.16	$64.82	$10.13	$50.70	$7.92
2023	$103.24	$17.71	$116.83	$20.04	$67.81	$10.59	$52.96	$8.27
2024	$106.97	$18.35	$121.02	$20.76	$70.25	$10.98	$54.64	$8.54

	******PLATT'S LOW POSTING @ USGC******			
	****0.5% SULFUR**** *DISTILLATE FUEL OIL* NOMINAL @ USGC		****0.3% SULFUR**** **DISTILLATE FUEL OIL NOMINAL @ USGC	
YEAR	CENTS/GAL	$/BBL	CENTS/GAL	$/BBL
1995	48.92	$20.55	52.95	$22.24
1996	51.96	$21.82	56.34	$23.66
1997	55.17	$23.17	59.98	$25.19
1998	59.47	$24.98	64.82	$27.22
1999	64.09	$26.92	70.06	$29.43
2000	67.42	$28.32	74.42	$31.26
2001	71.03	$29.83	78.96	$33.16
2002	74.70	$31.37	83.63	$35.12
2003	78.52	$32.98	88.65	$37.23
2004	82.52	$34.66	93.73	$39.37
2005	86.55	$36.35	99.00	$41.58
2006	91.30	$38.35	104.75	$43.99
2007	96.24	$40.42	110.66	$46.48
2008	101.61	$42.68	117.07	$49.17
2009	107.40	$45.11	123.77	$51.98
2010	113.64	$47.73	130.98	$55.01
2011	120.20	$50.48	138.41	$58.13
2012	127.37	$53.49	146.49	$61.53
2013	134.85	$56.64	154.92	$65.06
2014	142.86	$60.00	163.98	$68.87
2015	151.48	$63.62	173.70	$72.95
2016	160.60	$67.45	183.92	$77.25
2017	170.32	$71.53	194.78	$81.81
2018	180.55	$75.83	206.22	$86.61
2019	191.46	$80.41	218.30	$91.69
2020	203.05	$85.28	231.13	$97.07
2021	215.32	$90.43	244.76	$102.80
2022	228.27	$95.87	259.14	$108.84
2023	238.84	$100.31	271.19	$113.90
2024	247.48	$103.94	280.93	$117.99

NOTE 1: THE 0.5% SULFUR DISTILLATE FUEL OIL IS FOR THE GAS TURBINES AT FT. MYERS, LAUDERDALE AND PORT EVERGLADES, AND THE COMBINED CYCLE AT PUTNAM.
NOTE 2: THE 0.3% SULFUR DISTILLATE FUEL OIL IS FOR THE COMBINED CYCLE UNITS AT LAUDERDALE AND MARTIN.

PGBU - BUSINESS SYSTEMS
MARCH, 1995 - EU

1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR RESIDUAL (NO. 6) FUEL OIL PRICES BY SULFUR GRADE

MARCH 1995

YEAR	****0.7% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****3.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL	
	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1995	$18.47	$2.57	$15.32	$2.39	$15.13	$2.36	$14.93	$2.33	$14.74	$2.30	$14.55	$2.27
1996	$17.44	$2.73	$16.19	$2.53	$15.87	$2.48	$15.56	$2.43	$15.24	$2.38	$14.92	$2.33
1997	$18.48	$2.89	$17.11	$2.67	$16.67	$2.60	$16.24	$2.54	$15.80	$2.47	$15.36	$2.40
1998	$19.86	$3.10	$18.34	$2.87	$17.79	$2.78	$17.24	$2.69	$16.70	$2.61	$16.15	$2.52
1999	$21.36	$3.34	$19.66	$3.07	$19.01	$2.97	$18.36	$2.87	$17.71	$2.77	$17.06	$2.66
2000	$22.61	$3.53	$20.61	$3.22	$19.86	$3.10	$19.12	$2.99	$18.37	$2.87	$17.62	$2.75
2001	$23.94	$3.74	$21.68	$3.39	$20.85	$3.26	$20.02	$3.13	$19.18	$3.00	$18.35	$2.87
2002	$25.31	$3.95	$22.77	$3.56	$21.84	$3.41	$20.92	$3.27	$20.00	$3.12	$19.08	$2.98
2003	$26.78	$4.19	$23.90	$3.73	$22.88	$3.57	$21.86	$3.42	$20.85	$3.26	$19.83	$3.10
2004	$28.27	$4.42	$25.08	$3.92	$23.96	$3.74	$22.85	$3.57	$21.73	$3.40	$20.61	$3.22
2005	$29.82	$4.66	$26.27	$4.11	$25.05	$3.91	$23.83	$3.72	$22.61	$3.53	$21.39	$3.34
2006	$31.50	$4.92	$27.67	$4.32	$26.34	$4.12	$25.01	$3.91	$23.68	$3.70	$22.35	$3.49
2007	$33.24	$5.19	$29.13	$4.55	$27.70	$4.33	$26.27	$4.10	$24.83	$3.88	$23.40	$3.66
2008	$35.11	$5.49	$30.71	$4.80	$29.18	$4.56	$27.64	$4.32	$26.10	$4.08	$24.56	$3.84
2009	$37.08	$5.79	$32.42	$5.06	$30.77	$4.81	$29.12	$4.55	$27.47	$4.29	$25.82	$4.03
2010	$39.18	$6.12	$34.25	$5.35	$32.48	$5.08	$30.72	$4.80	$28.95	$4.52	$27.18	$4.25
2011	$41.35	$6.46	$36.17	$5.65	$34.28	$5.36	$32.39	$5.06	$30.50	$4.77	$28.61	$4.47
2012	$43.71	$6.83	$38.27	$5.98	$36.25	$5.66	$34.24	$5.35	$32.22	$5.03	$30.20	$4.72
2013	$46.17	$7.21	$40.46	$6.32	$38.31	$5.99	$36.16	$5.65	$34.01	$5.31	$31.86	$4.98
2014	$48.80	$7.63	$42.80	$6.69	$40.51	$6.33	$38.22	$5.97	$35.93	$5.6[illegible]	$33.63	$5.26
2015	$51.63	$8.07	$45.31	$7.08	$42.87	$6.70	$40.44	$6.32	$38.00	$5.94	$35.56	$5.56
2016	$54.60	$8.53	$47.98	$7.50	$45.38	$7.09	$42.79	$6.69	$40.19	$6.28	$37.60	$5.87
2017	$57.76	$9.02	$50.81	$7.94	$48.07	$7.51	$45.34	$7.08	$42.61	$6.66	$39.87	$6.23
2018	$61.08	$9.54	$53.79	$8.40	$50.91	$7.95	$48.03	$7.50	$45.15	$7.05	$42.27	$6.61
2019	$64.59	$10.09	$56.96	$8.90	$53.93	$8.43	$50.90	$7.95	$47.87	$7.48	$44.84	$7.01
2020	$68.31	$10.67	$60.33	$9.43	$57.14	$8.93	$53.95	$8.43	$50.76	$7.93	$47.57	$7.43
2021	$72.26	$11.29	$63.90	$9.98	$60.54	$9.46	$57.18	$8.93	$53.83	$8.41	$50.47	$7.89
2022	$76.42	$11.94	$67.66	$10.57	$64.13	$10.02	$60.60	$9.47	$57.07	$8.92	$53.54	$8.36
2023	$79.93	$12.49	$70.74	$11.05	$67.03	$10.47	$63.32	$9.89	$59.60	$9.31	$55.89	$8.73
2024	$82.78	$12.93	$73.28	$11.45	$69.38	$10.84	$65.48	$10.23	$61.57	$9.62	$57.67	$9.01

NOTE: RESIDUAL FUEL OIL PRICES ARE DELIVERED PRICES TO ALL FPL PLANT SITES.

PGBU - BUSINESS SYSTEMS
MARCH, 1994 - EU

1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

MARCH 1995

	*****NON-FIRM SERVICE****** ****(SUPPY AND TRANSPORTATION)****			********************PHASE II FIRM SUPPLY AND FIRM TRANSPORTATION************************									
				*************NATURAL GAS PRICE***********				TRANSPORATION COSTS				TOTAL DEMAND (SUNK) COST	
YEAR	NATURAL GAS PRICE $/MMBTU	TRANSPORT COMMODITY $/MMBTU	DELIVERED $/MMBTU	DEMAND $/MMBTU	COMMODITY $/MMBTU	BASIS $/MMBTU	TOTAL $/MMBTU	DEMAND $/MMBTU	COMMODITY $/MMBTU	CACTA $/MMBTU	TOTAL DELIVERED $/MMBTU	$/MMBTU	MM$
1995	$1.62	$0.41	$2.03	$0.06	$1.64	($0.02)	$1.69	$0.43	$0.11	($0.04)	$2.19	$0.90	$86.7
1996	$1.74	$0.42	$2.16	$0.07	$1.76	($0.02)	$1.80	$0.43	$0.11		$2.35	$0.99	$91.7
1997	$1.86	$0.44	$2.29	$0.07	$1.88	($0.02)	$1.93	$0.43	$0.12		$2.48	$1.02	$95.0
1998	$2.01	$0.44	$2.46	$0.08	$2.04	($0.02)	$2.09	$0.43	$0.12		$2.64	$1.07	$99.7
1999	$2.18	$0.43	$2.61	$0.09	$2.21	($0.03)	$2.27	$0.37	$0.09		$2.74	$1.07	$99.2
2000	$2.38	$0.45	$2.83	$0.09	$2.41	($0.03)	$2.48	$0.37	$0.10		$2.95	$1.13	$105.3
2001	$2.59	$0.46	$3.05	$0.10	$2.62	($0.03)	$2.69	$0.37	$0.10		$3.17	$1.20	$111.2
2002	$2.79	$0.48	$3.27	$0.11	$2.83	($0.03)	$2.90	$0.37	$0.11		$3.39	$1.26	$117.2
2003	$3.00	$0.49	$3.49	$0.12	$3.04	($0.04)	$3.12	$0.37	$0.12		$3.61	$1.33	$123.3
2004	$3.21	$0.49	$3.70	$0.13	$3.25	($0.04)	$3.34	$0.37	$0.12		$3.83	$1.40	$129.8
2005	$3.42	$0.50	$3.92	$0.13	$3.46	($0.04)	$3.55	$0.37	$0.13		$4.05	$1.31	$121.2
2006	$3.63	$0.50	$4.13	$0.14	$3.67	($0.04)	$3.77	$0.37	$0.13		$4.27	$1.15	$107.1
2007	$3.85	$0.51	$4.36	$0.15	$3.90	($0.05)	$4.00	$0.37	$0.14		$4.52	$1.23	$113.8
2008	$4.10	$0.52	$4.62	$0.16	$4.15	($0.05)	$4.26	$0.37	$0.15		$4.78	$1.31	$121.4
2009	$4.36	$0.52	$4.88	$0.17	$4.41	($0.05)	$4.53	$0.37	$0.15		$5.05	$1.39	$128.7
2010	$4.62	$0.53	$5.15	$0.18	$4.68	($0.06)	$4.80	$0.37	$0.16		$5.34	$0.23	$21.5
2011	$4.88	$0.54	$5.42	$0.19	$4.94	($0.06)	$5.07	$0.37	$0.17		$5.61	$0.00	$0.0
2012	$5.14	$0.55	$5.68	$0.20	$5.20	($0.06)	$5.34	$0.37	$0.18		$5.89	$0.00	$0.0
2013	$5.41	$0.55	$5.97	$0.21	$5.48	($0.07)	$5.62	$0.37	$0.18		$6.18	$0.00	$0.0
2014	$5.71	$0.56	$6.27	$0.22	$5.78	($0.07)	$5.93	$0.37	$0.19		$6.50	$0.00	$0.0
2015	$6.02	$0.57	$6.59	$0.24	$6.09	($0.07)	$6.25	$0.37	$0.20		$6.83	$0.00	$0.0
2016	$6.34	$0.58	$6.92	$0.25	$6.42	($0.08)	$6.59	$0.37	$0.21		$7.17	$0.00	$0.0
2017	$6.69	$0.59	$7.28	$0.26	$6.77	($0.08)	$6.95	$0.37	$0.22		$7.54	$0.00	$0.0
2018	$7.05	$0.60	$7.65	$0.28	$7.14	($0.09)	$7.33	$0.37	$0.23		$7.93	$0.00	$0.0
2019	$7.44	$0.61	$8.05	$0.29	$7.53	($0.09)	$7.73	$0.37	$0.24		$8.34	$0.00	$0.0
2020	$7.84	$0.62	$8.46	$0.31	$7.94	($0.10)	$8.15	$0.37	$0.25		$8.78	$0.00	$0.0
2021	$8.27	$0.63	$8.90	$0.32	$8.37	($0.10)	$8.59	$0.37	$0.27		$9.23	$0.00	$0.0
2022	$8.72	$0.65	$9.37	$0.34	$8.83	($0.11)	$9.06	$0.37	$0.28		$9.71	$0.00	$0.0
2023	$9.07	$0.66	$9.72	$0.35	$9.18	($0.11)	$9.42	$0.37	$0.29		$10.08	$0.00	$0.0
2024	$9.34	$0.66	$10.01	$0.37	$9.46	($0.12)	$9.71	$0.37	$0.30		$10.38	$0.00	$0.0

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1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

MARCH 1995

**************PHASE II NON-FIRM SUPPLY & FIRM TRANSPORTATION**************

YEAR	NATURAL GAS PRICE $/MMBTU	***TRANSPORATION COSTS*** DEMAND $/MMBTU	COMMODITY $/MMBTU	TOTAL DELIVERED $/MMBTU	TOTAL DEMAND (SUNK) COST $/MMBTU	MM$
1995	$1.62	$0.43	$0.11	$2.17	$0.43	$10.6
1996	$1.74	$0.43	$0.11	$2.28	$0.43	$12.4
1997	$1.86	$0.43	$0.12	$2.41	$0.43	$12.3
1998	$2.01	$0.43	$0.11	$2.56	$0.43	$12.3
1999	$2.18	$0.37	$0.09	$2.65	$0.37	$10.6
2000	$2.38	$0.37	$0.10	$2.85	$0.37	$10.7
2001	$2.59	$0.37	$0.10	$3.07	$0.37	$10.6
2002	$2.79	$0.37	$0.11	$3.27	$0.37	$10.6
2003	$3.00	$0.37	$0.11	$3.49	$0.37	$10.6
2004	$3.21	$0.37	$0.12	$3.70	$0.37	$10.7
2005	$3.42	$0.37	$0.12	$3.92	$0.22	$6.2
2006	$3.63	$0.37	$0.13	$4.13	$0.00	$0.0
2007	$3.85	$0.37	$0.14	$4.36	$0.00	$0.0
2008	$4.10	$0.37	$0.14	$4.62	$0.00	$0.0
2009	$4.36	$0.37	$0.15	$4.88	$0.00	$0.0
2010	$4.62	$0.37	$0.16	$5.15	$0.00	$0.0
2011	$4.88	$0.37	$0.17	$5.42	$0.00	$0.0
2012	$5.14	$0.37	$0.17	$5.68	$0.00	$0.0
2013	$5.41	$0.37	$0.18	$5.97	$0.00	$0.0
2014	$5.71	$0.37	$0.19	$6.27	$0.00	$0.0
2015	$6.02	$0.37	$0.20	$6.59	$0.00	$0.0
2016	$6.34	$0.37	$0.21	$6.92	$0.00	$0.0
2017	$6.69	$0.37	$0.22	$7.28	$0.00	$0.0
2018	$7.05	$0.37	$0.23	$7.65	$0.00	$0.0
2019	$7.44	$0.37	$0.24	$8.05	$0.00	$0.0
2020	$7.84	$0.37	$0.25	$8.46	$0.00	$0.0
2021	$8.27	$0.37	$0.26	$8.90	$0.00	$0.0
2022	$8.72	$0.37	$0.27	$9.37	$0.00	$0.0
2023	$9.07	$0.37	$0.28	$9.72	$0.00	$0.0
2024	$9.34	$0.37	$0.29	$10.01	$0.00	$0.0

**************PHASE III FIRM SUPPLY AND FIRM TRANSPORTATION**************

YEAR	******NATURAL GAS PRICE****** DEMAND $/MMBTU	COMMODITY $/MMBTU	TOTAL $/MMBTU	TRANSPORATION COSTS DEMAND $/MMBTU	COMMODITY $/MMBTU	CACTA $/MMBTU	TOTAL DELIVERED $/MMBTU	TOTAL DEMAND (SUNK) COST $/MMBTU	MM$
1995	$1.72	$0.00	$1.72	$0.75	$0.09	($0.04)	$2.53	$1.65	$50.4
1996	$1.84	$0.00	$1.84	$0.75	$0.10		$2.69	$1.90	$69.4
1997	$1.97	$0.00	$1.97	$0.75	$0.10		$2.82	$1.98	$72.1
1998	$2.13	$0.00	$2.13	$0.75	$0.11		$2.99	$2.08	$75.9
1999	$2.32	$0.00	$2.32	$0.75	$0.11		$3.18	$2.19	$80.1
2000	$2.53	$0.00	$2.53	$0.75	$0.12		$3.39	$2.32	$85.1
2001	$2.74	$0.00	$2.74	$0.75	$0.12		$3.62	$2.46	$89.7
2002	$2.94	$0.00	$2.94	$0.75	$0.13		$3.83	$2.58	$94.1
2003	$3.15	$0.00	$3.15	$0.75	$0.14		$4.04	$2.70	$98.7
2004	$3.36	$0.00	$3.36	$0.75	$0.14		$4.26	$2.83	$103.5
2005	$3.57	$0.00	$3.57	$0.75	$0.15		$4.47	$2.95	$107.8
2006	$3.78	$0.00	$3.78	$0.75	$0.16		$4.68	$3.08	$112.3
2007	$4.00	$0.00	$4.00	$0.75	$0.16		$4.92	$3.21	$117.3
2008	$4.25	$0.00	$4.25	$0.75	$0.17		$5.17	$3.36	$123.0
2009	$4.51	$0.00	$4.51	$0.75	$0.18		$5.44	$3.52	$128.3
2010	$4.77	$0.00	$4.77	$0.75	$0.19		$5.71	$0.61	$22.4
2011	$5.03	$0.00	$5.03	$0.75	$0.20		$5.98	$0.00	$0.0
2012	$5.29	$0.00	$5.29	$0.75	$0.20		$6.24	$0.00	$0.0
2013	$5.56	$0.00	$5.56	$0.75	$0.21		$6.53	$0.00	$0.0
2014	$5.86	$0.00	$5.86	$0.75	$0.22		$6.83	$0.00	$0.0
2015	$6.17	$0.00	$6.17	$0.75	$0.23		$7.15	$0.00	$0.0
2016	$6.49	$0.00	$6.49	$0.75	$0.24		$7.48	$0.00	$0.0
2017	$6.84	$0.00	$6.84	$0.75	$0.25		$7.84	$0.00	$0.0
2018	$7.20	$0.00	$7.20	$0.75	$0.26		$8.22	$0.00	$0.0
2019	$7.59	$0.00	$7.59	$0.75	$0.27		$8.61	$0.00	$0.0
2020	$7.99	$0.00	$7.99	$0.75	$0.29		$9.03	$0.00	$0.0
2021	$8.42	$0.00	$8.42	$0.75	$0.30		$9.47	$0.00	$0.0
2022	$8.87	$0.00	$8.87	$0.75	$0.31		$9.94	$0.00	$0.0
2023	$9.22	$0.00	$9.22	$0.75	$0.32		$10.29	$0.00	$0.0
2024	$9.49	$0.00	$9.49	$0.75	$0.33		$10.58	$0.00	$0.0

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DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

MARCH 1995

	***********PHASE III NON-FIRM SUPPLY & FIRM TRANSPORTATION***********											
	NATURAL GAS PRICE	***TRANSPORATION COSTS**		TOTAL DELIVERED	TOTAL DEMAND (SUNK) COST		SYSTEM WEIGHTED AVERAGE (NON-FIRM & FIRM) GAS PRICE		WEIGHTED AVERAGE FIRM GAS PRICE		TOTAL DEMAND (SUNK) COST	
YEAR	$/MMBTU	DEMAND $/MMBTU	COMMODITY $/MMBTU	$/MMBTU	$/MMBTU	MM$	$/MMBTU	MM$	$/MMBTU	MM$	$/MMBTU	MM$
1995	$1.62	$0.75	$0.11	$2.48	$0.75	$22.9	$2.26	$481.8	$2.29	$417.9	$0.94	$170.6
1996	$1.74	$0.75	$0.11	$2.60	$0.75	$27.5	$2.42	$535.1	$2.45	$477.4	$1.03	$201.0
1997	$1.86	$0.75	$0.12	$2.72	$0.75	$27.4	$2.55	$553.5	$2.58	$500.8	$1.07	$206.9
1998	$2.01	$0.75	$0.12	$2.89	$0.75	$27.4	$2.72	$580.2	$2.74	$532.7	$1.11	$215.4
1999	$2.18	$0.75	$0.13	$3.07	$0.75	$27.4	$2.85	$598.1	$2.87	$557.1	$1.12	$217.3
2000	$2.38	$0.75	$0.14	$3.27	$0.75	$27.5	$3.06	$633.6	$3.08	$599.4	$1.17	$228.5
2001	$2.59	$0.75	$0.15	$3.49	$0.75	$27.4	$3.29	$666.3	$3.30	$640.7	$1.23	$238.9
2002	$2.79	$0.75	$0.15	$3.70	$0.75	$27.4	$3.50	$709.4	$3.51	$681.9	$1.28	$249.3
2003	$3.00	$0.75	$0.16	$3.92	$0.75	$27.4	$3.72	$753.9	$3.73	$724.6	$1.34	$260.1
2004	$3.21	$0.75	$0.17	$4.13	$0.75	$27.5	$3.94	$800.3	$3.95	$769.1	$1.39	$271.5
2005	$3.42	$0.75	$0.18	$4.35	$0.75	$27.4	$4.16	$842.0	$4.17	$809.1	$1.35	$262.5
2006	$3.63	$0.75	$0.19	$4.56	$0.75	$27.4	$4.37	$886.1	$4.38	$851.4	$1.27	$246.8
2007	$3.85	$0.75	$0.19	$4.80	$0.75	$27.4	$4.61	$934.4	$4.62	$897.7	$1.33	$258.5
2008	$4.10	$0.75	$0.20	$5.05	$0.75	$27.5	$4.87	$989.5	$4.88	$950.7	$1.40	$272.0
2009	$4.36	$0.75	$0.21	$5.32	$0.75	$27.4	$5.14	$1,041.4	$5.15	$1,000.5	$1.46	$284.4
2010	$4.62	$0.75	$0.22	$5.60	$0.13	$4.6	$5.42	$1,098.1	$5.43	$1,054.8	$0.25	$48.5
2011	$4.88	$0.75	$0.23	$5.87	$0.00	$0.0	$5.69	$1,152.7	$5.70	$1,107.2	$0.00	$0.0
2012	$5.14	$0.75	$0.24	$6.13	$0.00	$0.0	$5.96	$1,210.6	$5.97	$1,162.8	$0.00	$0.0
2013	$5.41	$0.75	$0.26	$6.42	$0.00	$0.0	$6.25	$1,266.1	$6.26	$1,216.0	$0.00	$0.0
2014	$5.71	$0.75	$0.27	$6.73	$0.00	$0.0	$6.56	$1,329.0	$6.57	$1,276.4	$0.00	$0.0
2015	$6.02	$0.75	$0.28	$7.05	$0.00	$0.0	$6.88	$1,394.1	$6.89	$1,338.8	$0.00	$0.0
2016	$6.34	$0.75	$0.29	$7.38	$0.00	$0.0	$7.22	$1,467.4	$7.23	$1,409.1	$0.00	$0.0
2017	$6.69	$0.75	$0.30	$7.74	$0.00	$0.0	$7.58	$1,536.8	$7.60	$1,475.7	$0.00	$0.0
2018	$7.05	$0.75	$0.32	$8.12	$0.00	$0.0	$7.97	$1,614.5	$7.98	$1,550.2	$0.00	$0.0
2019	$7.44	$0.75	$0.33	$8.52	$0.00	$0.0	$8.37	$1,696.3	$8.39	$1,628.7	$0.00	$0.0
2020	$7.84	$0.75	$0.35	$8.94	$0.00	$0.0	$8.80	$1,787.2	$8.81	$1,715.9	$0.00	$0.0
2021	$8.27	$0.75	$0.36	$9.38	$0.00	$0.0	$9.24	$1,872.5	$9.26	$1,797.8	$0.00	$0.0
2022	$8.72	$0.75	$0.38	$9.86	$0.00	$0.0	$9.72	$1,969.0	$9.73	$1,890.4	$0.00	$0.0
2023	$9.07	$0.75	$0.40	$10.22	$0.00	$0.0	$10.08	$2,042.5	$10.10	$1,960.9	$0.00	$0.0
2024	$9.34	$0.75	$0.41	$10.50	$0.00	$0.0	$10.37	$2,107.3	$10.39	$2,023.0	$0.00	$0.0

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NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY (SEE NOTE 1)

MARCH, 1995

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	FIRM TRANSPORTATION SERVICE: PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 3) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 1995	68	132	255	0	0	0	323
FEBRUARY	72	132	255	0	0	0	327
MARCH	125	32	200	60	55	140	580
APRIL	150	32	200	60	80	140	630
MAY	50	128	330	60	100	140	680
JUNE	50	128	330	60	100	140	680
JULY	50	128	330	60	100	140	680
AUGUST	50	128	330	60	100	140	680
SEPTEMBER	50	128	330	60	100	140	680
OCTOBER	150	32	200	60	80	140	630
NOVEMBER	125	32	200	60	55	140	580
DECEMBER	95	32	200	60	55	140	550
JANUARY 1996	45	32	200	60	55	140	500
FEBRUARY	75	32	200	60	55	140	530
MARCH	110	32	200	60	55	140	565
APRIL	130	32	200	60	80	140	610
MAY	40	128	330	60	100	140	670
JUNE	40	128	330	60	100	140	670
JULY	40	128	330	60	100	140	670
AUGUST	40	128	330	60	100	140	670
SEPTEMBER	40	128	330	60	100	140	670
OCTOBER	130	32	200	60	80	140	610
NOVEMBER	110	32	200	60	55	140	565
DECEMBER	75	32	200	60	55	140	530
JANUARY 1997	35	32	200	60	55	140	490
FEBRUARY	65	32	200	60	55	140	520
MARCH	100	32	200	60	55	140	555
APRIL	120	32	200	60	80	140	600
MAY	30	128	330	60	100	140	660
JUNE	30	128	330	60	100	140	660
JULY	30	128	330	60	100	140	660
AUGUST	30	128	330	60	100	140	660
SEPTEMBER	30	128	330	60	100	140	660
OCTOBER	120	32	200	60	80	140	600
NOVEMBER	100	32	200	60	55	140	555
DECEMBER	65	32	200	60	55	140	520
JANUARY 1998	25	32	200	60	55	140	480
FEBRUARY	55	32	200	60	55	140	510
MARCH	90	32	200	60	55	140	545
APRIL	110	32	200	60	80	140	590
MAY	20	128	330	60	100	140	650
JUNE	20	128	330	60	100	140	650
JULY	20	128	330	60	100	140	650
AUGUST	20	128	330	60	100	140	650
SEPTEMBER	20	128	330	60	100	140	650
OCTOBER	110	32	200	60	80	140	590
NOVEMBER	90	32	200	60	55	140	545
DECEMBER	55	32	200	60	55	140	510
1995	86	88	263	50	69	117	585
1996	73	71	254	60	78	140	605
1997	63	71	254	60	78	140	595
1998	53	71	254	60	78	140	585

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	FIRM TRANSPORTATION SERVICE: PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 3) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 1999	15	32	200	60	55	140	470
FEBRUARY	45	32	200	60	55	140	500
MARCH	80	32	200	60	55	140	535
APRIL	100	32	200	60	80	140	580
MAY	10	128	330	60	100	140	640
JUNE	10	128	330	60	100	140	640
JULY	10	128	330	60	100	140	640
AUGUST	10	128	330	60	100	140	640
SEPTEMBER	10	128	330	60	100	140	640
OCTOBER	100	32	200	60	80	140	580
NOVEMBER	80	32	200	60	55	140	535
DECEMBER	45	32	200	60	55	140	500
JANUARY 2000	5	32	200	60	55	140	460
FEBRUARY	35	32	200	60	55	140	490
MARCH	70	32	200	60	55	140	525
APRIL	90	32	200	60	80	140	570
MAY	0	128	330	60	100	140	630
JUNE	0	128	330	60	100	140	630
JULY	0	128	330	60	100	140	630
AUGUST	0	128	330	60	100	140	630
SEPTEMBER	0	128	330	60	100	140	630
OCTOBER	90	32	200	60	80	140	570
NOVEMBER	70	32	200	60	55	140	525
DECEMBER	35	32	200	60	55	140	490
JANUARY 2001	0	32	200	60	55	140	455
FEBRUARY	15	32	200	60	55	140	470
MARCH	50	32	200	60	55	140	505
APRIL	70	32	200	60	80	140	550
MAY	0	128	330	60	100	140	630
JUNE	0	128	330	60	100	140	630
JULY	0	128	330	60	100	140	630
AUGUST	0	128	330	60	100	140	630
SEPTEMBER	0	128	330	60	100	140	630
OCTOBER	70	32	200	60	80	140	550
NOVEMBER	50	32	200	60	55	140	505
DECEMBER	15	32	200	60	55	140	470
JANUARY 2002	0	32	200	60	55	140	455
FEBRUARY	15	32	200	60	55	140	470
MARCH	50	32	200	60	55	140	505
APRIL	70	32	200	60	80	140	550
MAY	0	128	330	60	100	140	630
JUNE	0	128	330	60	100	140	630
JULY	0	128	330	60	100	140	630
AUGUST	0	128	330	60	100	140	630
SEPTEMBER	0	128	330	60	100	140	630
OCTOBER	70	32	200	60	80	140	550
NOVEMBER	50	32	200	60	55	140	505
DECEMBER	15	32	200	60	55	140	470
1999	43	71	254	60	78	140	575
2000	33	71	254	60	78	140	565
2001	23	71	254	60	78	140	555
2002	23	71	254	60	78	140	555

NOTE 1: FOR YEARS 2003 THROUGH 2024, MONTHLY NON-FIRM AND FIRM AVAILABILITIES WILL EQUAL THE CORRESPONDING MONTHLY AVAILABILITIES IN 2002.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVICE FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 3: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1995 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (I.e THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTATIO SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010 THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

PGBU - BUSINESS SYSTEMS
MARCH, 1995 - EU

1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL PRICES TO SCHERER UNIT 4 & THE MARTIN SITE

MARCH 1995

FORECAST ASSUMES THAT THE MARTIN COAL PLANT WILL STARTUP IN 2004

YEAR	PLANT SCHERER UNIT 4				MARTIN PLANT: LOW SULFUR COAL				MARTIN PLANT: HIGH SULFUR COAL			
	WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL	
	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1995	$32.30	$1.69	$26.39	$1.53	$43.72	$1.79	$43.72	$1.79	$41.81	$1.82	$41.81	$1.82
1996	$32.31	$1.71	$26.98	$1.55	$45.58	$1.87	$45.58	$1.87	$42.36	$1.84	$42.36	$1.84
1997	$32.99	$1.74	$27.65	$1.58	$47.45	$1.94	$47.45	$1.94	$43.09	$1.87	$43.09	$1.87
1998	$33.13	$1.79	$28.32	$1.67	$49.10	$2.01	$49.10	$2.01	$44.26	$1.92	$44.26	$1.92
1999	$33.36	$1.83	$29.07	$1.71	$50.79	$2.08	$50.79	$2.08	$45.58	$1.98	$45.58	$1.98
2000	$33.63	$1.86	$29.91	$1.76	$52.33	$2.14	$52.33	$2.14	$46.95	$2.04	$46.95	$2.04
2001	$34.64	$1.91	$30.71	$1.81	$53.91	$2.21	$53.91	$2.21	$48.68	$2.12	$48.68	$2.12
2002	$35.69	$1.97	$31.53	$1.85	$55.66	$2.28	$55.66	$2.28	$50.41	$2.19	$50.41	$2.19
2003	$37.09	$2.05	$32.38	$1.90	$57.31	$2.35	$57.55	$2.36	$51.92	$2.26	$52.19	$2.27
2004	$38.26	$2.11	$33.31	$1.96	$58.99	$2.42	$59.46	$2.44	$53.51	$2.33	$54.16	$2.35
2005	$39.47	$2.17	$34.23	$2.01	$60.70	$2.49	$61.41	$2.52	$55.11	$2.40	$56.11	$2.44
2006	$40.74	$2.24	$35.21	$2.07	$62.51	$2.56	$63.46	$2.60	$56.79	$2.47	$58.14	$2.53
2007	$42.08	$2.31	$36.22	$2.13	$65.57	$2.69	$65.64	$2.69	$60.30	$2.62	$60.37	$2.62
2008	$43.76	$2.40	$37.30	$2.19	$67.63	$2.77	$67.90	$2.78	$62.24	$2.71	$62.62	$2.72
2009	$38.34	$2.26	$38.38	$2.26	$69.74	$2.86	$70.18	$2.88	$64.26	$2.79	$65.00	$2.83
2010	$39.41	$2.32	$39.48	$2.32	$71.90	$2.95	$72.47	$2.97	$66.34	$2.88	$67.43	$2.93
2011	$40.51	$2.38	$40.61	$2.39	$74.11	$3.04	$74.82	$3.07	$68.45	$2.98	$69.85	$3.04
2012	$41.62	$2.45	$41.76	$2.46	$77.18	$3.16	$77.34	$3.17	$72.21	$3.14	$72.38	$3.15
2013	$42.94	$2.53	$42.94	$2.53	$79.60	$3.26	$80.17	$3.29	$74.44	$3.24	$74.93	$3.26
2014	$44.12	$2.60	$44.18	$2.60	$82.19	$3.37	$83.40	$3.42	$76.76	$3.34	$77.57	$3.37
2015	$45.36	$2.67	$45.49	$2.68	$84.98	$3.48	$87.05	$3.57	$79.17	$3.44	$80.34	$3.49
2016	$46.64	$2.74	$46.85	$2.76	$87.90	$3.60	$90.88	$3.72	$81.68	$3.55	$83.22	$3.62
2017	$47.97	$2.82	$48.26	$2.84	$94.86	$3.89	$95.12	$3.90	$85.98	$3.74	$86.26	$3.75
2018	$49.76	$2.93	$49.76	$2.93	$98.18	$4.02	$99.46	$4.08	$88.75	$3.86	$89.43	$3.89
2019	$51.20	$3.01	$51.31	$3.02	$101.62	$4.16	$103.98	$4.26	$91.63	$3.98	$92.74	$4.03
2020	$52.69	$3.10	$52.90	$3.11	$105.15	$4.31	$108.60	$4.45	$94.62	$4.11	$96.18	$4.18
2021	$54.22	$3.19	$54.55	$3.21	$108.81	$4.46	$113.39	$4.65	$97.70	$4.25	$99.73	$4.34
2022	$55.81	$3.28	$56.26	$3.31	$117.86	$4.83	$118.25	$4.85	$103.02	$4.48	$103.43	$4.50
2023	$58.03	$3.41	$58.03	$3.41	$121.84	$4.99	$123.13	$5.05	$106.38	$4.63	$107.30	$4.67
2024	$59.74	$3.51	$59.86	$3.52	$125.97	$5.16	$128.24	$5.26	$109.85	$4.78	$111.28	$4.84

PGBU - BUSINESS SYSTEMS
MARCH, 1995 - EU

1995 TO 2024 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL TO SJRPP, ORIMULSION TO MANATEE & MARTIN, & COKE PRICES

MARCH 1995

YEAR	(SEE NOTE 1) DELIVERED ST. JOHNS RIVER POWER PARK COAL PRICES — CONTRACT PRICE NOMINAL $/TON	CONTRACT PRICE NOMINAL $/MMBTU	SPOT PRICE NOMINAL $/TON	SPOT PRICE NOMINAL $/MMBTU	WEIGHTED AVERAGE NOMINAL $/TON	WEIGHTED AVERAGE NOMINAL $/MMBTU	(SEE NOTE 2) DELIVERED NOMINAL ORIMULSION TO PRICES — MANATEE BASE PRICE $/MMBTU	MANATEE EXCESS PRICE $/MMBTU	MARTIN BASE PRICE $/MMBTU	MARTIN EXCESS PRICE $/MMBTU	PETROLEUM COKE $/MMBTU
1995	$38.86	$1.59	$32.11	$1.40	$36.69	$1.52	$1.66	$1.22	$1.80	$1.35	$0.90
1996	$40.18	$1.65	$32.49	$1.41	$37.42	$1.56	$1.72	$1.23	$1.86	$1.37	$0.93
1997	$43.84	$1.78	$33.01	$1.44	$38.56	$1.61	$1.86	$1.25	$2.00	$1.39	$0.96
1998	$41.88	$1.72	$33.92	$1.47	$39.04	$1.63	$1.80	$1.29	$1.95	$1.44	$0.99
1999	$42.37	$1.75	$34.94	$1.52	$39.69	$1.66	$1.83	$1.33	$1.98	$1.48	$1.02
2000	$43.65	$1.80	$36.00	$1.57	$40.90	$1.71	$1.88	$1.37	$2.04	$1.53	$1.05
2001	$44.92	$1.86	$37.39	$1.63	$42.21	$1.77	$1.94	$1.43	$2.10	$1.59	$1.09
2002	$41.76	$1.78	$38.76	$1.69	$40.86	$1.75	$1.87	$1.49	$2.03	$1.65	$1.12
2003	$40.15	$1.75	$40.18	$1.75	$40.16	$1.75	$1.83	$1.54	$2.00	$1.71	$1.16
2004	$41.27	$1.79	$41.77	$1.82	$41.42	$1.80	$1.88	$1.61	$2.06	$1.78	$1.19
2005	$42.40	$1.84	$43.33	$1.88	$42.68	$1.86	$1.94	$1.67	$2.12	$1.85	$1.23
2006	$43.60	$1.90	$44.96	$1.95	$44.01	$1.91	$1.99	$1.74	$2.18	$1.92	$1.27
2007	$44.92	$1.95	$46.75	$2.03	$45.47	$1.98	$2.05	$1.81	$2.24	$2.00	$1.31
2008	$48.48	$2.11	$48.54	$2.11	$48.49	$2.11	$2.21	$1.88	$2.41	$2.08	$1.37
2009	$49.95	$2.17	$50.44	$2.19	$50.09	$2.18	$2.27	$1.96	$2.48	$2.16	$1.42
2010	$51.46	$2.24	$52.39	$2.28	$51.74	$2.25	$2.34	$2.04	$2.56	$2.25	$1.46
2011	$53.01	$2.30	$54.32	$2.36	$53.40	$2.32	$2.41	$2.11	$2.63	$2.34	$1.51
2012	$54.58	$2.37	$56.34	$2.45	$55.11	$2.40	$2.48	$2.20	$2.71	$2.42	$1.55
2013	$58.26	$2.53	$58.37	$2.54	$58.30	$2.53	$2.64	$2.28	$2.88	$2.51	$1.62
2014	$59.98	$2.61	$60.49	$2.63	$60.13	$2.61	$2.72	$2.36	$2.97	$2.61	$1.68
2015	$61.76	$2.69	$62.69	$2.73	$62.04	$2.70	$2.80	$2.45	$3.05	$2.70	$1.73
2016	$63.61	$2.77	$65.00	$2.83	$64.03	$2.78	$2.89	$2.55	$3.15	$2.81	$1.79
2017	$65.54	$2.85	$67.42	$2.93	$66.11	$2.87	$2.97	$2.64	$3.24	$2.91	$1.86
2018	$69.80	$3.03	$69.96	$3.04	$69.85	$3.04	$3.16	$2.75	$3.44	$3.02	$2.02
2019	$71.93	$3.13	$72.62	$3.16	$72.14	$3.14	$3.26	$2.85	$3.54	$3.14	$2.09
2020	$74.13	$3.22	$75.37	$3.28	$74.51	$3.24	$3.36	$2.97	$3.65	$3.26	$2.16
2021	$76.41	$3.32	$78.21	$3.40	$76.95	$3.35	$3.46	$3.08	$3.77	$3.39	$2.24
2022	$78.76	$3.42	$81.18	$3.53	$79.49	$3.46	$3.57	$3.20	$3.88	$3.52	$2.32
2023	$84.07	$3.66	$84.29	$3.66	$84.14	$3.66	$3.80	$3.33	$4.13	$3.65	$2.50
2024	$86.65	$3.77	$87.49	$3.80	$86.90	$3.78	$3.92	$3.46	$4.26	$3.79	$2.59

NOTE 1: ST. JOHNS RIVER POWER PARK PRICES INCLUDE VARIABLE O & M COSTS.
NOTE 2: ORIMULSION PRICES DOES NOT INCLUDE ANY O & M COSTS.

PGBU-BUSINESS SYSTEMS
MARCH, 1995 - EU

Inter-Office Correspondence

FPL

TO: Distribution

DATE: March 26, 1996

FROM: R. Silva
E. Ungar
J. Wehner

LOCATION: QPA/JB

SUBJECT: **FPL Long-Term (1996-2025) Base Case Fossil Fuel Price & Natural Gas Availability Forecast**

Attached is the updated FPL long-term base case fossil fuel price forecast for crude oil, residual and distillate fuel oil, natural gas, coal, Orimulsion, and petroleum coke, as well as, the projected availability of natural gas to FPL.

The forecast methodology, underlying assumptions and resulting forecast values were developed jointly by PGBU Business Systems and QPA. This forecast supersedes the March 31, 1995 FPL long-term base case forecast and should be used, together with the alternate scenario forecasts to be issued by May 1996, in the 1996 Integrated Resource Planning process and all other long-term analyses for the 1996 to 2025 period.

The following describes the most significant changes between this and last year's forecast:

o Lower than previously projected crude oil prices linked primarily to lower general inflationary expectations and technology improvements which will reduce finding costs (see Table 1 which compares the FPL crude oil price forecast to alternative published crude oil price forecasts). **As a result, the 2005 delivered nominal price of low sulfur residual fuel oil is about 3.9% lower than last year's forecast (see Table 2)**

o More optimistic assessment of the level of natural gas supply consistent with higher estimates of natural gas resources and advances in drilling technology and analysis of seismic data. For instance, the 1995 United States Geological Survey assessment of US oil and natural gas reserves increased since 1989. **As a result of the above factors, the 2005 delivered natural gas price forecast is approximately 13.5% lower than last year's forecast (see Table 3)**

  Recent very high natural gas prices, primarily due to severe cold weather and lower than expected increases in capacity to deliver natural gas, are not expected to continue beyond 1996. This current market condition will be continually monitored in preparation for the development of the May 1996 to December 2001 short-term fuel price forecast.

o The projected delivered nominal price of coal, Orimulsion and petroleum coke is slightly lower than last year's forecast due primarily to lower general inflationary expectations. **The 2005 average delivered price of coal is about 1.3% lower than last year's forecast.**

Detailed fuel price forecasts are not attached due to: 1) confidentiality of contractual terms reflected in the detailed fuel price projections; and 2) sensitivity to increasing competition. If you need specific fuel price forecasts or if you have any questions concerning forecast assumptions, please contact either Eugene Ungar at 552-3412 or John Wehner at 694-3411.

R. Silva

E. Ungar

J. C. Wehner

EU/JW
Attachments

Distribution: (Crude oil, residual fuel and natural gas tables only)

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Table 1

Crude Oil Price Forecast

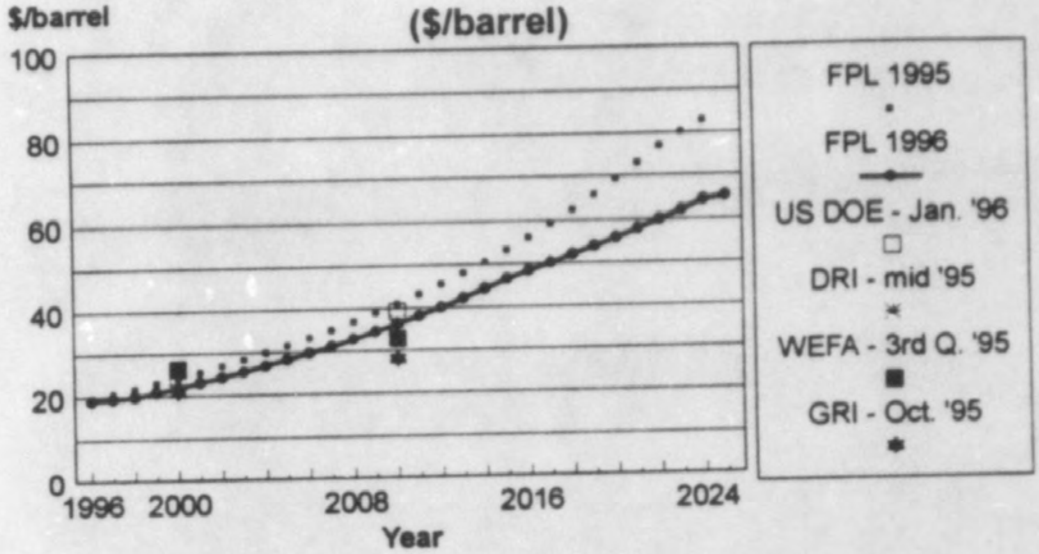


Table 2

Delivered 1% Residual Fuel
($/barrel)

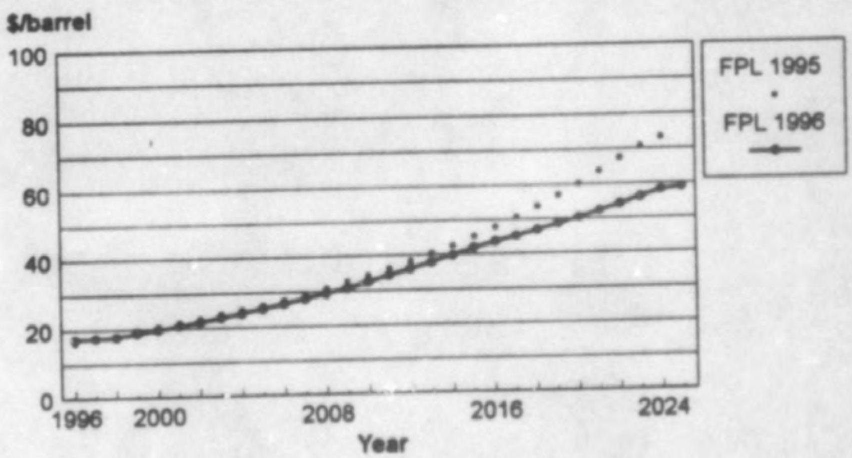
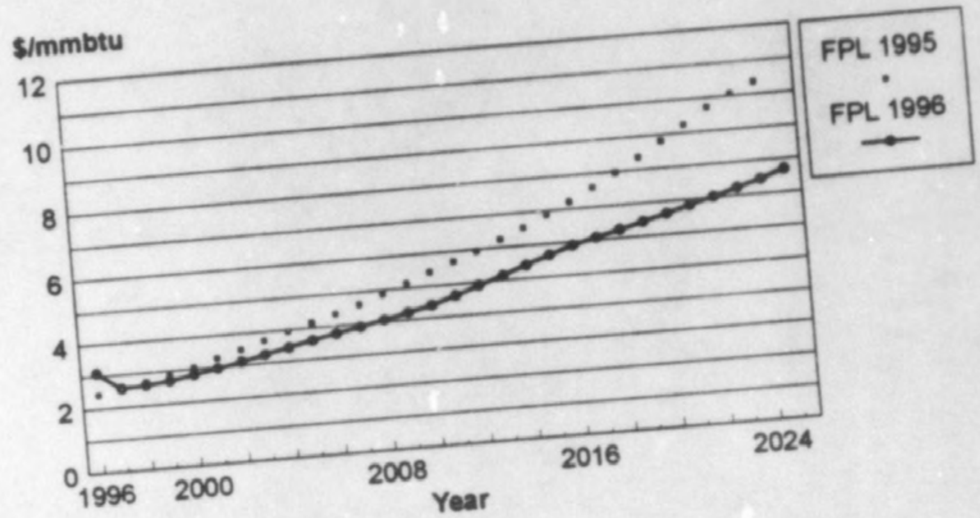
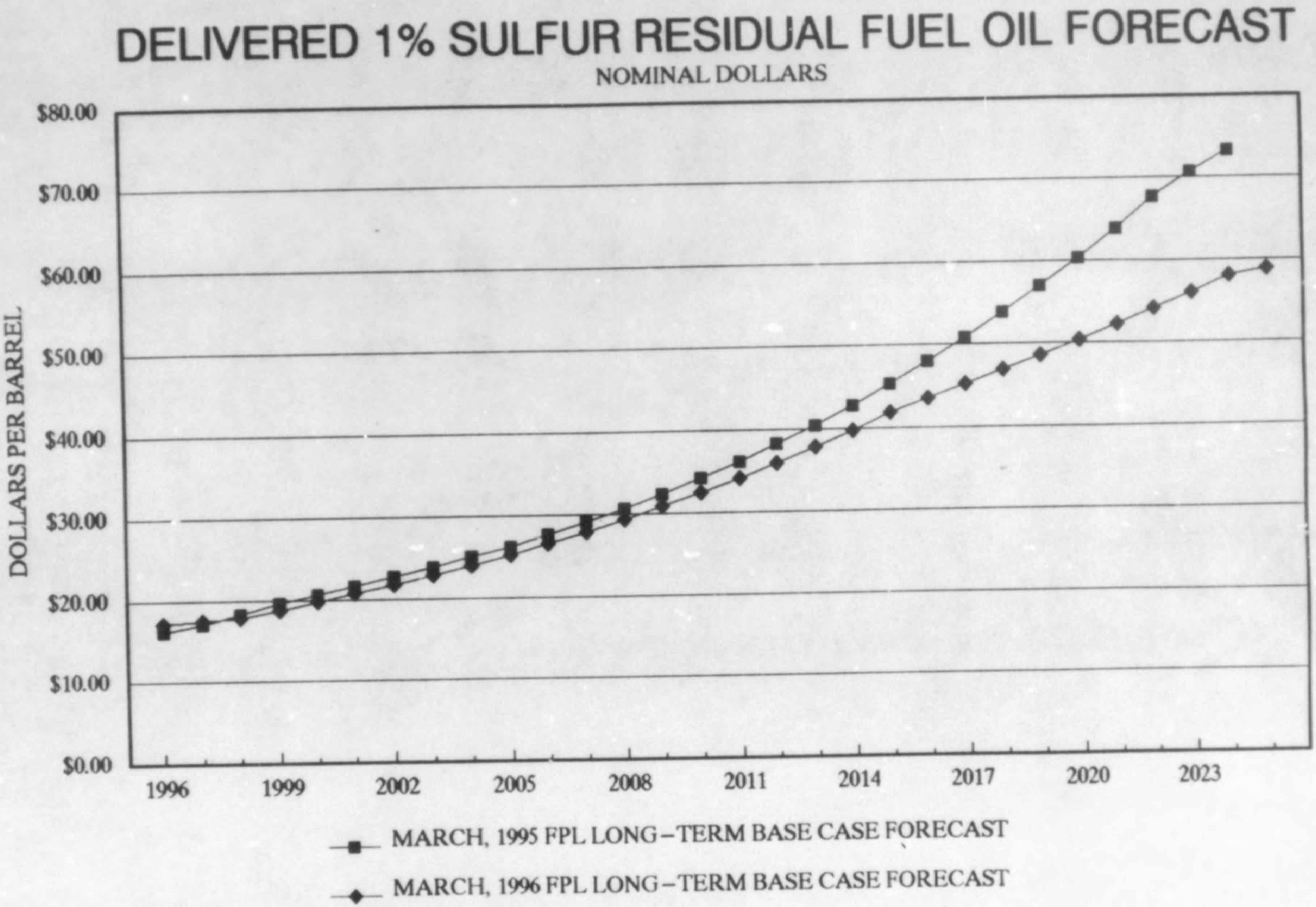


Table 3

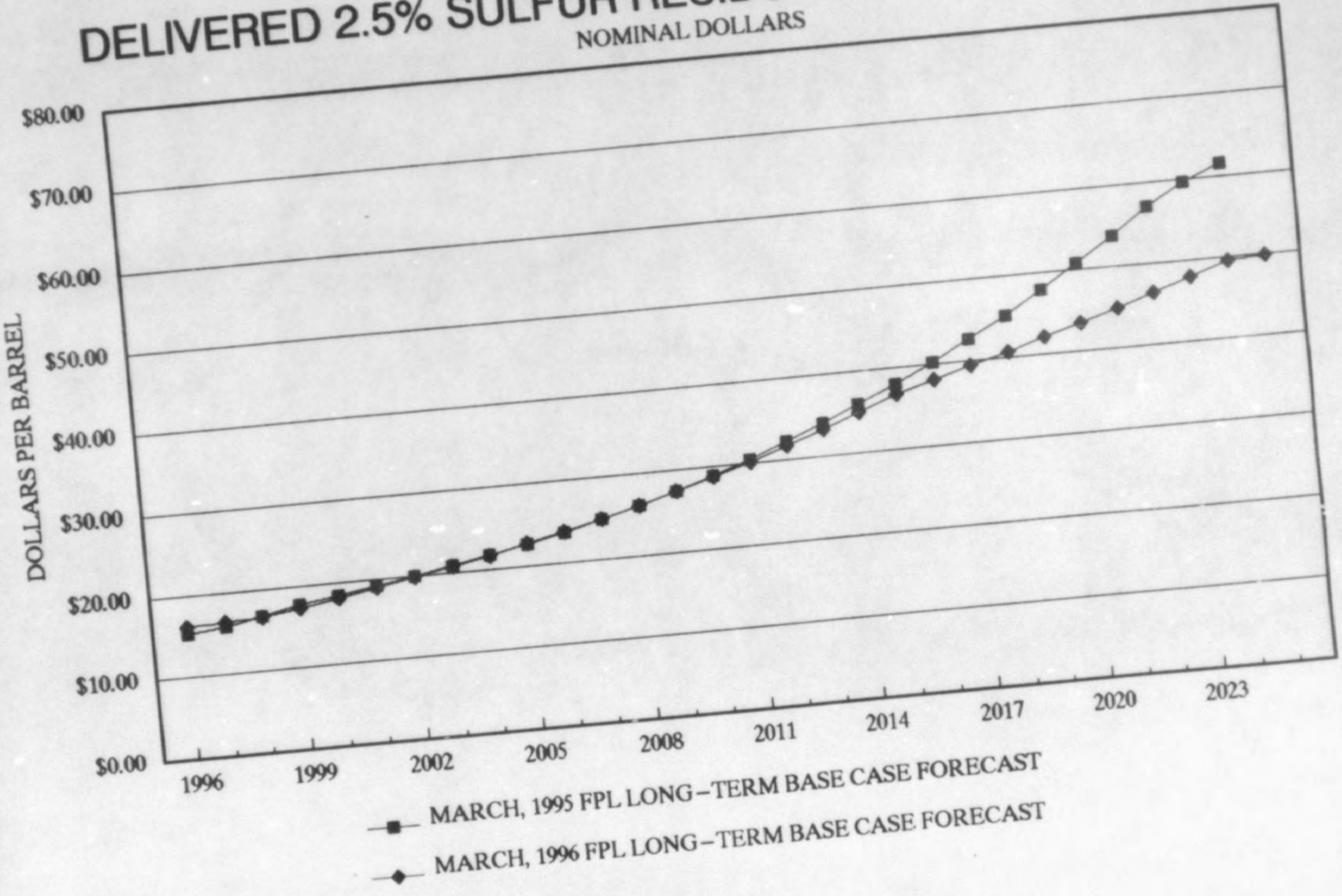
Delivered Natural Gas
($/mmbtu)

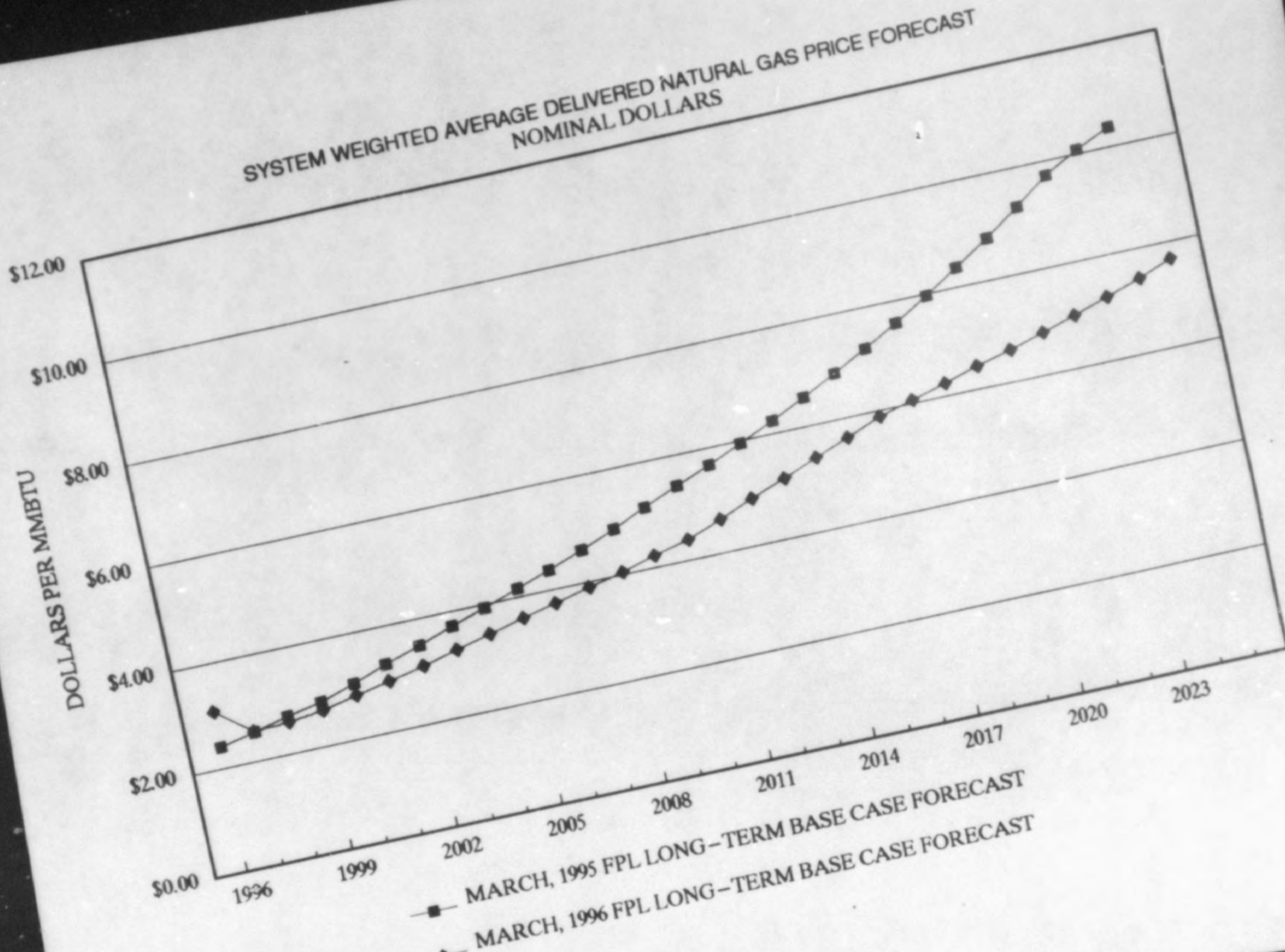




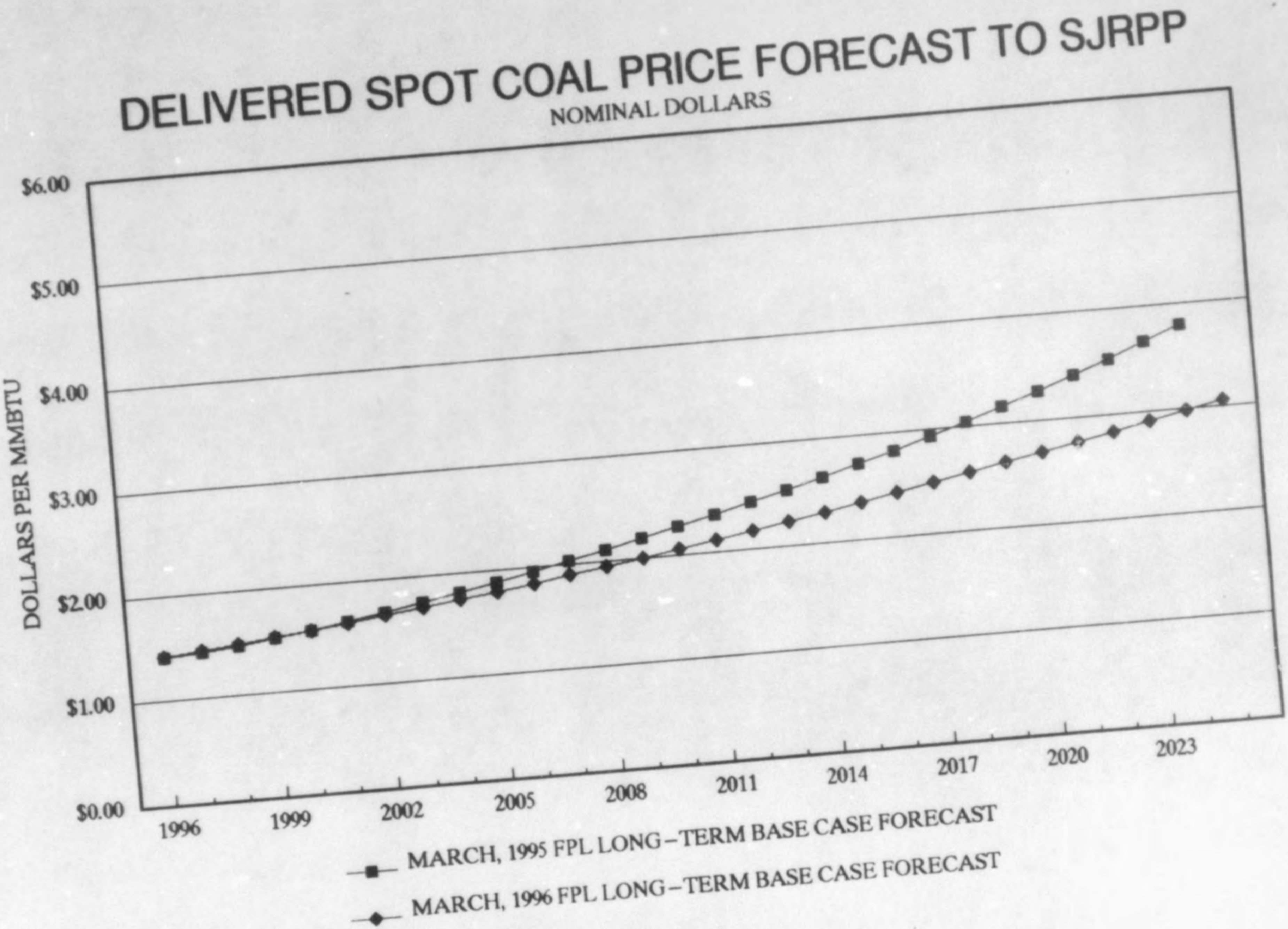
DELIVERED 1% SULFUR RESIDUAL FUEL OIL FORECAST
NOMINAL DOLLARS
DOLLARS PER BARREL
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG-TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG-TERM BASE CASE FORECAST

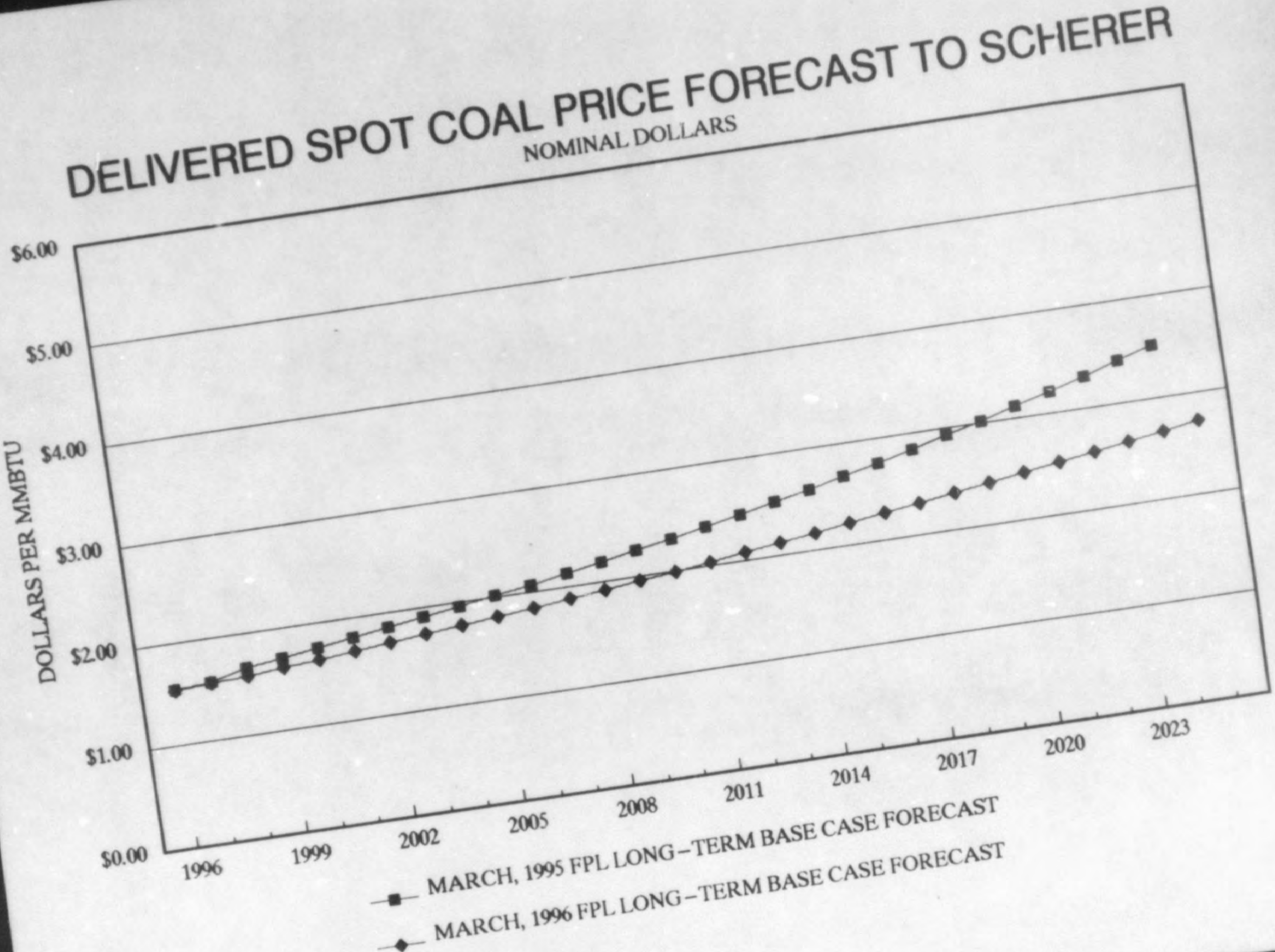
DELIVERED 2.5% SULFUR RESIDUAL FUEL OIL FORECAST

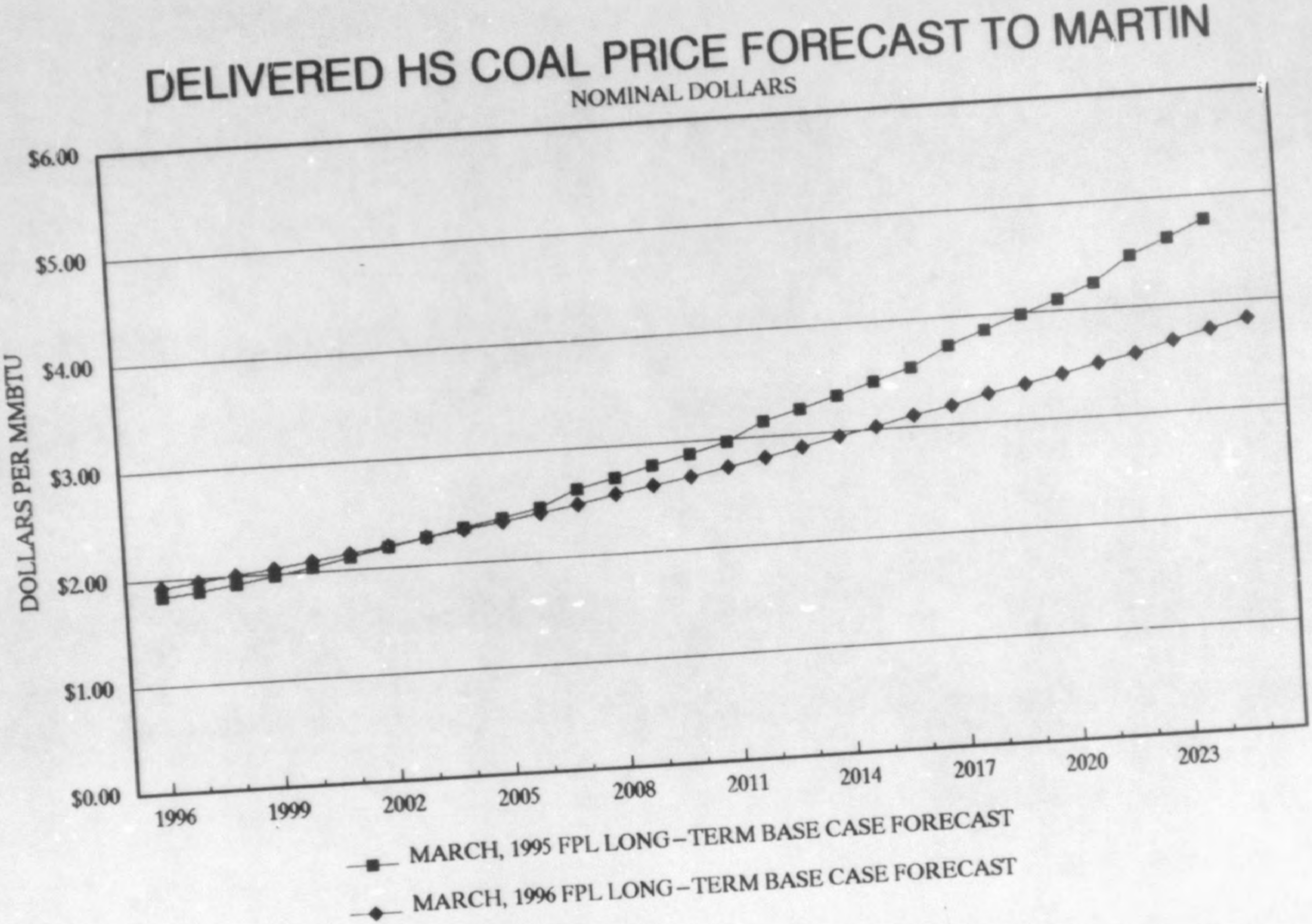


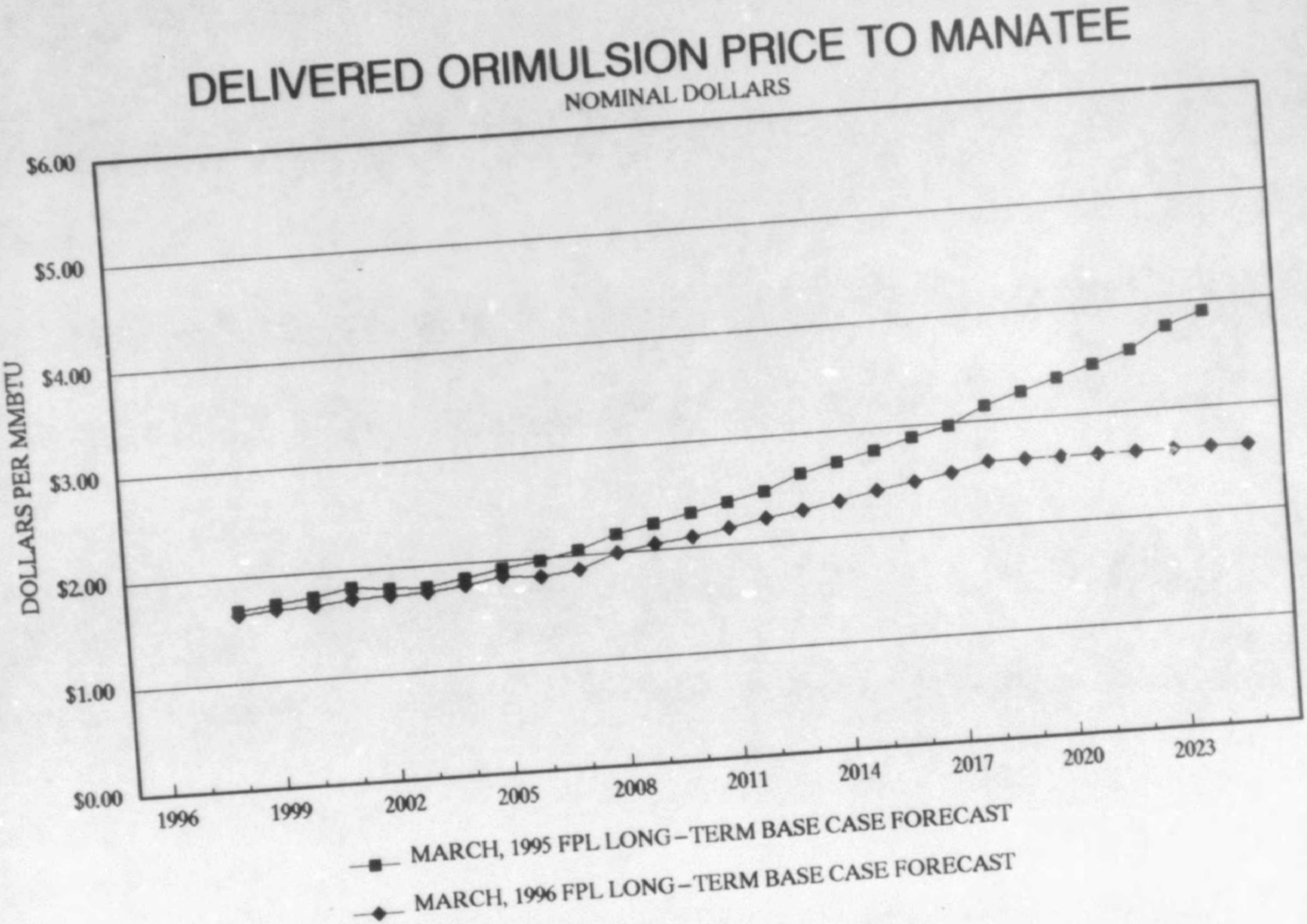


SYSTEM WEIGHTED AVERAGE DELIVERED NATURAL GAS PRICE FORECAST
NOMINAL DOLLARS
DOLLARS PER MMBTU
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG-TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG-TERM BASE CASE FORECAST


DELIVERED SPOT COAL PRICE FORECAST TO SJRPP
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG-TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG-TERM BASE CASE FORECAST

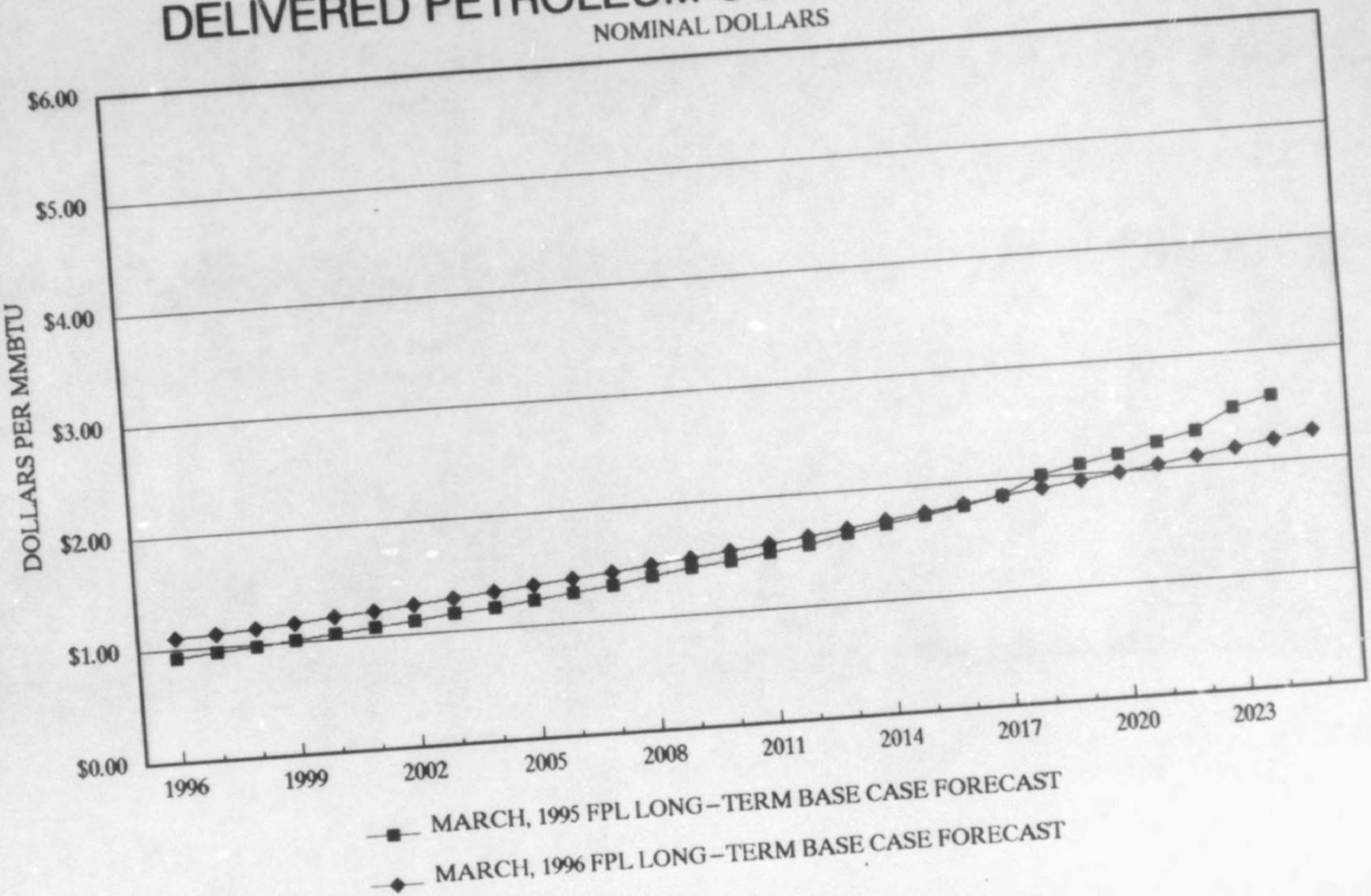

DELIVERED SPOT COAL PRICE FORECAST TO SCHERER
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG-TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG-TERM BASE CASE FORECAST

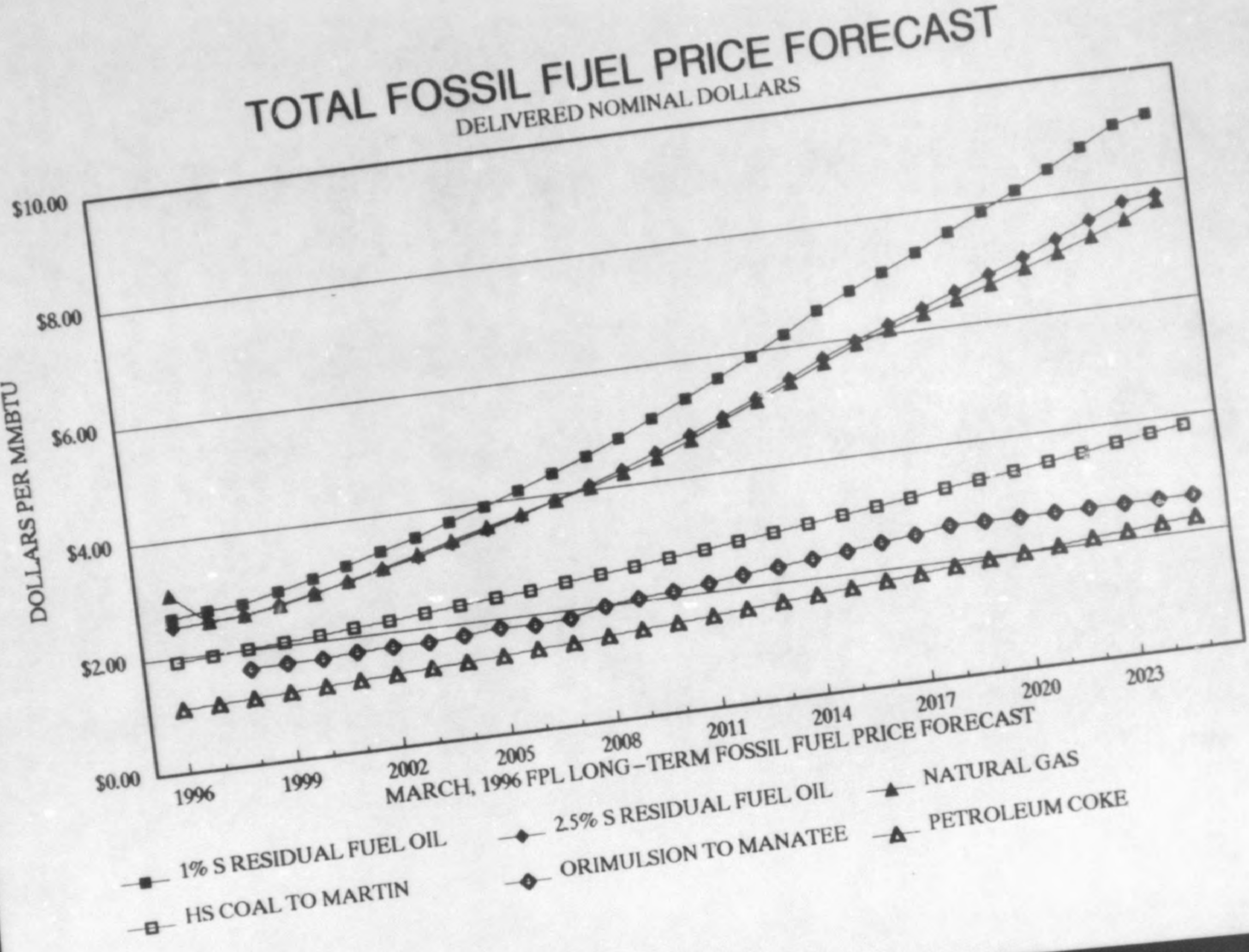

DELIVERED HS COAL PRICE FORECAST TO MARTIN
NOMINAL DOLLARS
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
DOLLARS PER MMBTU
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG-TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG-TERM BASE CASE FORECAST


DELIVERED ORIMULSION PRICE TO MANATEE
NOMINAL DOLLARS
DOLLARS PER MMBTU
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1995 FPL LONG–TERM BASE CASE FORECAST
MARCH, 1996 FPL LONG–TERM BASE CASE FORECAST

DELIVERED PETROLEUM COKE PRICE FORECAST

NOMINAL DOLLARS




TOTAL FOSSIL FUEL PRICE FORECAST
DELIVERED NOMINAL DOLLARS
DOLLARS PER MMBTU
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
MARCH, 1996 FPL LONG-TERM FOSSIL FUEL PRICE FORECAST
1% S RESIDUAL FUEL OIL
2.5% S RESIDUAL FUEL OIL
NATURAL GAS
HS COAL TO MARTIN
ORIMULSION TO MANATEE
PETROLEUM COKE

1996 TO 2025 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

NOMINAL DOLLAR CRUDE OIL, DELIVERED DISTILLATE (NO. 2) & U.S.G.C. RESIDUAL & DISTILLATE FUEL OIL PRICES

MARCH 1996

YEAR	*******NOMINAL CRUDE OIL PRICES******** ***ARABIAN LIGHT*** $/BBL	$/MMBTU	****WEST TEXAS***** ***INTERMEDIATE**** $/BBL	$/MMBTU	(SEE NOTE 1) *****0.5% SULFUR***** **DISTILLATE FUEL OIL** DELIVERED NOMINAL $/BBL	$/MMBTU	(SEE NOTE 2) *****0.3% SULFUR***** **DISTILLATE FUEL OIL* DELIVERED NOMINAL $/BBL	$/MMBTU	*****PLATT'S LOW POSTING @ USGC****** ****1.0% SULFUR**** **RESIDUAL FUEL OIL* NOMINAL @ USGC $/BBL	$/MMBTU	****3.0% SULFUR**** *RESIDUAL FUEL OIL* NOMINAL @ USGC $/BBL	$/MMBTU	*****PLATT'S LOW POSTING @ USGC****** ****0.5% SULFUR***** *DISTILLATE FUEL OIL* NOMINAL @ USGC CENTS/GAL	$/BBL	****0.3% SULFUR**** *DISTILLATE FUEL OIL NOMINAL @ USGC CENTS/GAL	$/BBL
1996	$17.47	$3.00	$19.00	$3.26	$23.08	$3.96	$24.86	$4.26	$15.90	$2.48	$14.57	$2.28	52.00	$21.84	56.23	$23.62
1997	$17.85	$3.06	$19.50	$3.34	$23.70	$4.07	$25.80	$4.39	$16.29	$2.55	$14.77	$2.31	53.41	$22.43	57.92	$24.33
1998	$18.11	$3.11	$19.89	$3.41	$24.19	$4.15	$26.18	$4.49	$16.58	$2.59	$14.87	$2.32	54.49	$22.89	59.24	$24.88
1999	$19.00	$3.26	$20.92	$3.59	$25.46	$4.37	$27.65	$4.74	$17.45	$2.73	$15.53	$2.43	57.50	$24.15	62.67	$26.32
2000	$19.94	$3.42	$21.99	$3.77	$26.83	$4.60	$29.20	$5.01	$18.35	$2.87	$16.23	$2.54	60.64	$25.47	66.30	$27.85
2001	$20.91	$3.59	$23.12	$3.97	$28.26	$4.85	$31.05	$5.33	$19.32	$3.02	$16.96	$2.65	63.96	$26.86	70.61	$29.65
2002	$21.94	$3.76	$24.30	$4.17	$29.76	$5.10	$32.92	$5.65	$20.33	$3.18	$17.73	$2.77	67.45	$28.33	74.97	$31.49
2003	$23.02	$3.95	$25.55	$4.38	$31.36	$5.38	$34.92	$5.99	$21.40	$3.34	$18.54	$2.90	71.17	$29.89	79.66	$33.46
2004	$24.16	$4.14	$26.86	$4.61	$33.04	$5.67	$37.11	$6.37	$22.52	$3.52	$19.41	$3.03	75.09	$31.54	84.78	$35.61
2005	$25.37	$4.35	$28.24	$4.84	$34.82	$5.97	$39.33	$6.75	$23.71	$3.71	$20.33	$3.18	79.25	$33.28	89.98	$37.79
2006	$26.63	$4.57	$29.69	$5.09	$36.70	$6.30	$41.75	$7.16	$24.97	$3.90	$21.30	$3.33	83.63	$35.12	95.65	$40.17
2007	$27.95	$4.79	$31.21	$5.35	$38.68	$6.64	$44.15	$7.57	$26.28	$4.11	$22.31	$3.49	88.24	$37.06	101.25	$42.53
2008	$29.36	$5.04	$32.82	$5.63	$40.80	$7.00	$46.66	$8.00	$27.69	$4.33	$23.40	$3.66	93.17	$39.13	107.14	$45.00
2009	$30.83	$5.29	$34.50	$5.92	$43.01	$7.38	$49.30	$8.46	$29.16	$4.56	$24.55	$3.84	98.35	$41.31	113.31	$47.59
2010	$32.39	$5.56	$36.27	$6.22	$45.36	$7.78	$52.01	$8.92	$30.72	$4.80	$25.78	$4.03	103.84	$43.61	119.66	$50.26
2011	$34.02	$5.84	$38.13	$6.54	$47.84	$8.21	$54.85	$9.41	$32.36	$5.06	$27.06	$4.23	109.63	$46.04	126.33	$53.06
2012	$35.74	$6.13	$40.09	$6.88	$50.46	$8.66	$57.84	$9.92	$34.10	$5.33	$28.43	$4.44	115.76	$48.62	133.33	$56.00
2013	$37.55	$6.44	$42.15	$7.23	$53.24	$9.13	$60.94	$10.45	$35.93	$5.61	$29.86	$4.67	122.25	$51.34	140.60	$59.05
2014	$39.46	$6.77	$44.31	$7.60	$56.16	$9.63	$64.24	$11.[illegible]	$37.86	$5.92	$31.40	$4.91	129.09	$54.22	148.32	$62.30
2015	$41.45	$7.11	$46.58	$7.99	$59.24	$10.16	$67.72	$11.62	$39.89	$6.23	$33.01	$5.16	136.30	$57.25	156.48	$65.72
2016	$43.01	$7.38	$48.42	$8.31	$61.74	$10.59	$70.51	$12.10	$41.51	$6.49	$34.18	$5.34	142.13	$59.70	163.02	$68.47
2017	$44.53	$7.64	$50.23	$8.62	$64.21	$11.01	$73.23	$12.56	$43.10	$6.73	$35.32	$5.52	147.89	$62.11	169.36	$71.13
2018	$46.07	$7.90	$52.06	$8.93	$66.73	$11.45	$75.99	$13.03	$44.72	$6.99	$36.46	$5.70	153.78	$64.58	175.81	$73.84
2019	$47.66	$8.17	$53.95	$9.25	$69.30	$11.89	$78.89	$13.53	$46.39	$7.25	$37.67	$5.89	159.83	$67.13	182.58	$76.68
2020	$49.29	$8.45	$55.89	$9.59	$72.03	$12.35	$81.81	$14.03	$48.12	$7.52	$38.90	$6.08	166.12	$69.77	189.41	$79.55
2021	$50.98	$8.74	$57.90	$9.93	$74.82	$12.83	$84.83	$14.55	$49.90	$7.80	$40.17	$6.28	172.64	$72.51	196.46	$82.51
2022	$52.71	$9.04	$59.97	$10.29	$77.71	$13.33	$87.99	$15.09	$51.75	$8.09	$41.48	$6.48	179.39	$75.34	203.87	$85.63
2023	$54.51	$9.35	$62.12	$10.65	$80.71	$13.84	$91.29	$15.66	$53.66	$8.38	$42.84	$6.69	186.78	$78.28	211.59	$88.87
2024	$56.35	$9.67	$64.32	$11.03	$83.81	$14.38	$94.81	$16.26	$55.64	$8.69	$44.24	$6.91	193.63	$81.32	219.82	$92.32
2025	$56.92	$9.76	$65.26	$11.19	$85.07	$14.59	$96.23	$16.51	$56.35	$8.80	$44.35	$6.93	196.50	$82.53	223.07	$93.69

NOTE 1: THE 0.5% SULFUR DISTILLATE FUEL OIL IS FOR THE GAS TURBINES AT FT. MYERS, LAUDERDALE AND PORT EVERGLADES, AND THE COMBINED CYCLE AT PUTNAM.
NOTE 2: THE 0.3% SULFUR DISTILLATE FUEL OIL IS FOR THE COMBINED CYCLE UNITS AT LAUDERDALE AND MARTIN.

PGBU - BUSINESS SYSTEMS
MARCH, 1996 - EU

1996 TO 2025 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR RESIDUAL (NO. 6) FUEL OIL PRICES BY SULFUR GRADE

MARCH 1996

	****0.7% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****1.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****2.5% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL		****3.0% SULFUR***** **RESIDUAL FUEL OIL* DELIVERED NOMINAL	
YEAR	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU	$/BBL	$/MMBTU
1996	$18.44	$2.88	$17.14	$2.68	$16.81	$2.63	$16.48	$2.57	$16.15	$2.52	$15.82	$2.47
1997	$18.94	$2.96	$17.56	$2.74	$17.18	$2.68	$16.80	$2.63	$16.42	$2.57	$16.05	$2.51
1998	$19.32	$3.02	$17.88	$2.79	$17.45	$2.73	$17.02	$2.66	$16.60	$2.59	$16.17	$2.53
1999	$20.35	$3.18	$18.78	$2.93	$18.30	$2.86	$17.82	$2.78	$17.34	$2.71	$16.86	$2.63
2000	$21.43	$3.35	$19.72	$3.08	$19.19	$3.00	$18.65	$2.91	$18.12	$2.83	$17.59	$2.75
2001	$22.72	$3.55	$20.71	$3.24	$20.12	$3.14	$19.53	$3.05	$18.94	$2.96	$18.35	$2.87
2002	$24.02	$3.75	$21.76	$3.40	$21.11	$3.30	$20.46	$3.20	$19.81	$3.09	$19.16	$2.99
2003	$25.41	$3.97	$22.86	$3.57	$22.15	$3.46	$21.44	$3.35	$20.72	$3.24	$20.01	$3.13
2004	$26.93	$4.21	$24.02	$3.75	$23.25	$3.63	$22.47	$3.51	$21.69	$3.39	$20.91	$3.27
2005	$28.46	$4.45	$25.25	$3.95	$24.41	$3.81	$23.56	$3.68	$22.72	$3.55	$21.87	$3.42
2006	$30.14	$4.71	$26.55	$4.15	$25.63	$4.00	$24.71	$3.86	$23.79	$3.72	$22.86	$3.57
2007	$31.78	$4.97	$27.91	$4.36	$26.91	$4.21	$25.92	$4.05	$24.93	$3.89	$23.93	$3.74
2008	$33.51	$5.24	$29.36	$4.59	$28.28	$4.42	$27.21	$4.25	$26.14	$4.08	$25.07	$3.92
2009	$35.31	$5.52	$30.87	$4.82	$29.72	$4.64	$28.57	$4.46	$27.41	$4.28	$26.26	$4.10
2010	$37.16	$5.81	$32.47	$5.07	$31.24	$4.88	$30.00	$4.69	$28.76	$4.49	$27.53	$4.30
2011	$39.09	$6.11	$34.16	$5.34	$32.84	$5.13	$31.51	$4.92	$30.18	$4.72	$28.86	$4.51
2012	$41.12	$6.42	$35.94	$5.62	$34.53	$5.39	$33.11	$5.17	$31.69	$4.95	$30.27	$4.73
2013	$43.22	$6.75	$37.83	$5.91	$36.31	$5.67	$34.80	$5.44	$33.28	$5.20	$31.77	$4.96
2014	$45.45	$7.10	$39.80	$6.22	$38.19	$5.97	$36.57	$5.71	$34.96	$5.46	$33.34	$5.21
2015	$47.79	$7.47	$41.89	$6.54	$40.17	$6.28	$38.44	$6.01	$36.72	$5.74	$35.00	$5.47
2016	$49.66	$7.76	$43.56	$6.81	$41.73	$6.52	$39.89	$6.23	$38.05	$5.95	$36.23	$5.66
2017	$51.46	$8.04	$45.20	$7.06	$43.26	$6.76	$41.31	$6.45	$39.37	$6.15	$37.42	$5.85
2018	$53.28	$8.33	$46.87	$7.32	$44.81	$7.00	$42.75	$6.68	$40.69	$6.36	$38.63	$6.04
2019	$55.20	$8.62	$48.59	$7.59	$46.41	$7.25	$44.23	$6.91	$42.05	$6.57	$39.87	$6.23
2020	$57.12	$8.93	$50.37	$7.87	$48.07	$7.51	$45.77	$7.15	$43.46	$6.79	$41.16	$6.43
2021	$59.10	$9.23	$52.21	$8.16	$49.78	$7.78	$47.35	$7.40	$44.92	$7.02	$42.48	$6.64
2022	$61.18	$9.56	$54.12	$8.46	$51.55	$8.05	$48.98	$7.65	$46.42	$7.25	$43.85	$6.85
2023	$63.34	$9.90	$56.09	$8.76	$53.38	$8.34	$50.67	$7.92	$47.97	$7.50	$45.26	$7.07
2024	$65.64	$10.26	$58.12	$9.08	$55.27	$8.64	$52.42	$8.19	$49.57	$7.75	$46.72	$7.30
2025	$66.51	$10.39	$58.89	$9.20	$55.89	$8.73	$52.89	$8.26	$49.90	$7.80	$46.90	$7.33

NOTE: RESIDUAL FUEL OIL PRICES ARE DELIVERED PRICES TO ALL FPL PLANT SITES.

PGBU – BUSINESS SYSTEMS
MARCH, 1996 – EU

1996 TO 2026 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR NATURAL GAS PRICES

MARCH 1996

	A=B+E SYSTEM WEIGHTED TOTAL (NON-FIRM & FIRM) NATURAL GAS PRICE		B=C+D TOTAL COST OF NATURAL GAS PRICE MOVING UNDER FIRM TRANSPORTATION		C DEMAND (SUNK) COST FOR NATURAL GAS MOVING UNDER FIRM TRANSPORTATION		D VARIABLE (DISPATCH) COST FOR NATURAL GAS MOVING UNDER FIRM TRANSPORTATION		E VARIABLE (DISPATCH) COST FOR NATURAL GAS MOVING UNDER NON-FIRM TRANSPORTATION	
YEAR	$/MMBTU	MM$	$/MMBTU	MM$	$/MMBTU	MM$	$/MMBTU	MM$	$/MMBTU	MM$
1996	$3.09	$825.4	$3.18	$616.9	$1.22	$236.8	$1.96	$380	$2.86	$208.5
1997	$2.57	$678.2	$2.64	$515.0	$1.08	$210.3	$1.56	$305	$2.35	$163.2
1998	$2.61	$678.5	$2.68	$521.2	$1.09	$210.9	$1.60	$310	$2.39	$157.3
1999	$2.69	$690.0	$2.76	$535.4	$1.09	$211.1	$1.67	$324	$2.49	$154.6
2000	$2.82	$713.5	$2.88	$560.4	$1.12	$217.6	$1.76	$343	$2.62	$153.2
2001	$2.96	$740.2	$3.02	$588.5	$1.16	$225.1	$1.87	$363	$2.76	$151.7
2002	$3.11	$763.5	$3.17	$614.8	$1.19	$231.7	$1.97	$383	$2.91	$148.7
2003	$3.27	$789.9	$3.32	$644.3	$1.23	$239.2	$2.09	$405	$3.07	$145.6
2004	$3.43	$829.0	$3.48	$675.5	$1.27	$247.1	$2.21	$428	$3.23	$153.5
2005	$3.59	$870.2	$3.64	$708.6	$1.31	$255.6	$2.33	$453	$3.40	$161.6
2006	$3.74	$903.8	$3.79	$735.7	$1.26	$243.8	$2.53	$492	$3.54	$168.1
2007	$3.90	$942.2	$3.95	$766.7	$1.16	$225.7	$2.78	$541	$3.70	$175.5
2008	$4.05	$978.8	$4.10	$796.2	$1.20	$233.2	$2.90	$563	$3.85	$182.6
2009	$4.22	$1,023.4	$4.27	$832.2	$1.24	$242.3	$3.03	$590	$4.02	$191.2
2010	$4.39	$1,060.6	$4.44	$862.2	$1.29	$249.8	$3.15	$612	$4.18	$198.4
2011	$4.63	$1,119.1	$4.68	$909.4	$0.22	$42.9	$4.46	$866	$4.42	$209.7
2012	$4.88	$1,180.1	$4.94	$958.6	$0.00	$0.0	$4.94	$959	$4.67	$221.5
2013	$5.14	$1,244.5	$5.19	$1,010.7	$0.00	$0.0	$5.19	$1,011	$4.92	$233.9
2014	$5.39	$1,302.2	$5.44	$1,057.2	$0.00	$0.0	$5.44	$1,057	$5.16	$245.0
2015	$5.64	$1,363.4	$5.70	$1,106.6	$0.00	$0.0	$5.70	$1,107	$5.41	$256.9
2016	$5.89	$1,424.7	$5.95	$1,156.0	$0.00	$0.0	$5.95	$1,156	$5.66	$268.7
2017	$6.08	$1,472.4	$6.13	$1,194.5	$0.00	$0.0	$6.13	$1,195	$5.84	$277.9
2018	$6.26	$1,512.1	$6.31	$1,226.5	$0.00	$0.0	$6.31	$1,227	$6.02	$285.6
2019	$6.44	$1,555.8	$6.50	$1,261.8	$0.00	$0.0	$6.50	$1,262	$6.20	$294.0
2020	$6.62	$1,599.6	$6.68	$1,297.1	$0.00	$0.0	$6.68	$1,297	$6.37	$302.4
2021	$6.82	$1,652.9	$6.88	$1,340.1	$0.00	$0.0	$6.88	$1,340	$6.57	$312.7
2022	$7.01	$1,694.7	$7.07	$1,373.9	$0.00	$0.0	$7.07	$1,374	$6.76	$320.8
2023	$7.22	$1,746.0	$7.29	$1,415.3	$0.00	$0.0	$7.29	$1,415	$6.97	$330.7
2024	$7.44	$1,797.4	$7.50	$1,456.8	$0.00	$0.0	$7.50	$1,457	$7.18	$340.6
2025	$7.68	$1,861.4	$7.74	$1,508.4	$0.00	$0.0	$7.74	$1,508	$7.42	$353.0

PGBU - BUSINESS SYSTEMS
MARCH, 1996 - EU

1996 TO 2025 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

NATURAL GAS AVAILABILITY IN MILLIONS OF CUBIC FEET PER DAY (SEE NOTE 1)

MARCH, 1996

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 3) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 1996	265	32	200	80	55	140	720
FEBRUARY	265	32	200	80	55	140	720
MARCH	265	32	200	80	55	140	720
APRIL	265	32	200	80	80	140	745
MAY	110	128	330	80	100	140	740
JUNE	110	128	330	80	100	140	740
JULY	110	128	330	80	100	140	740
AUGUST	110	128	330	80	100	140	740
SEPTEMBER	110	128	330	80	100	140	740
OCTOBER	265	32	200	80	80	140	745
NOVEMBER	265	32	200	80	55	140	720
DECEMBER	265	32	200	80	55	140	720
JANUARY 1997	255	32	200	80	55	140	710
FEBRUARY	255	32	200	80	55	140	710
MARCH	255	32	200	80	55	140	710
APRIL	255	32	200	80	80	140	735
MAY	100	128	330	80	100	140	730
JUNE	100	128	330	80	100	140	730
JULY	100	128	330	80	100	140	730
AUGUST	100	128	330	80	100	140	730
SEPTEMBER	100	128	330	80	100	140	730
OCTOBER	255	32	200	80	80	140	735
NOVEMBER	255	32	200	80	55	140	710
DECEMBER	255	32	200	80	55	140	710
JANUARY 1998	245	32	200	80	55	140	700
FEBRUARY	245	32	200	80	55	140	700
MARCH	245	32	200	80	55	140	700
APRIL	245	32	200	80	80	140	725
MAY	90	128	330	80	100	140	720
JUNE	90	128	330	80	100	140	720
JULY	90	128	330	80	100	140	720
AUGUST	90	128	330	80	100	140	720
SEPTEMBER	90	128	330	80	100	140	720
OCTOBER	245	32	200	80	80	140	725
NOVEMBER	245	32	200	80	55	140	700
DECEMBER	245	32	200	80	55	140	700
JANUARY 1999	235	32	200	80	55	140	690
FEBRUARY	235	32	200	80	55	140	690
MARCH	235	32	200	80	55	140	690
APRIL	235	32	200	80	80	140	715
MAY	80	128	330	80	100	140	710
JUNE	80	128	330	80	100	140	710
JULY	80	128	330	80	100	140	710
AUGUST	80	128	330	80	100	140	710
SEPTEMBER	80	128	330	80	100	140	710
OCTOBER	235	32	200	80	80	140	715
NOVEMBER	235	32	200	80	55	140	690
DECEMBER	235	32	200	80	55	140	690
1996	200	71	254	80	78	140	733
1997	190	71	254	80	78	140	723
1998	180	71	254	80	78	140	713
1999	170	71	254	80	78	140	703

MONTH	NON-FIRM TRANSPORT SERVICE	FIRM TRANSPORTATION SERVICE: PHASE II FIRM GAS SUPPLY GAS SUPPLY TAKE OR PAY MINIMUM	PHASE II FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III FIRM GAS SUPPLY (TAKE OR PAY) (SEE NOTE 3) FIXED	PHASE II NON-FIRM GAS SUPPLY (SEE NOTE 2) MAXIMUM	PHASE III NON-FIRM GAS SUPPLY (SEE NOTE 3) MAXIMUM	TOTAL (MAXIMUM) NATURAL GAS AVAILABILITY
JANUARY 2000	225	32	200	80	55	140	680
FEBRUARY	225	32	200	80	55	140	680
MARCH	225	32	200	80	55	140	680
APRIL	225	32	200	80	80	140	705
MAY	70	128	330	80	100	140	700
JUNE	70	128	330	80	100	140	700
JULY	70	128	330	80	100	140	700
AUGUST	70	128	330	80	100	140	700
SEPTEMBER	70	128	330	80	100	140	700
OCTOBER	225	32	200	80	80	140	705
NOVEMBER	225	32	200	80	55	140	680
DECEMBER	225	32	200	80	55	140	680
JANUARY 2001	215	32	200	80	55	140	670
FEBRUARY	215	32	200	80	55	140	670
MARCH	215	32	200	80	55	140	670
APRIL	215	32	200	80	80	140	695
MAY	60	128	330	80	100	140	690
JUNE	60	128	330	80	100	140	690
JULY	60	128	330	80	100	140	690
AUGUST	60	128	330	80	100	140	690
SEPTEMBER	60	128	330	80	100	140	690
OCTOBER	215	32	200	80	80	140	695
NOVEMBER	215	32	200	80	55	140	670
DECEMBER	215	32	200	80	55	140	670
JANUARY 2002	205	32	200	80	55	140	660
FEBRUARY	205	32	200	80	55	140	660
MARCH	205	32	200	80	55	140	660
APRIL	205	32	200	80	80	140	685
MAY	50	128	330	80	100	140	680
JUNE	50	128	330	80	100	140	680
JULY	50	128	330	80	100	140	680
AUGUST	50	128	330	80	100	140	680
SEPTEMBER	50	128	330	80	100	140	680
OCTOBER	205	32	200	80	80	140	685
NOVEMBER	205	32	200	80	55	140	660
DECEMBER	205	32	200	80	55	140	660
JANUARY 2003	195	32	200	80	55	140	650
FEBRUARY	195	32	200	80	55	140	650
MARCH	195	32	200	80	55	140	650
APRIL	195	32	200	80	80	140	675
MAY	40	128	330	80	100	140	670
JUNE	40	128	330	80	100	140	670
JULY	40	128	330	80	100	140	670
AUGUST	40	128	330	80	100	140	670
SEPTEMBER	40	128	330	80	100	140	670
OCTOBER	195	32	200	80	80	140	675
NOVEMBER	195	32	200	80	55	140	650
DECEMBER	195	32	200	80	55	140	650
2000	160	71	254	80	78	140	693
2001	150	71	254	80	78	140	683
2002	140	71	254	80	78	140	673
2003	130	71	254	80	78	140	663

NOTE 1: FOR YEARS 2004 THROUGH 2025, MONTHLY NON-FIRM AND FIRM AVAILABILITIES WILL EQUAL THE CORRESPONDING MONTHLY AVAILABILITIES IN 2003.

NOTE 2: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1996 THROUGH JULY, 2005, ASSUME THAT UP TO 332 MILLION CUBIC FEET PER DAY OF THE PHASE II TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM AUGUST, 2005 FORWARD, ASSUME THAT THESE PHASE II VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (i.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE II TRANSPORTATION SERVI(FPL WILL COMMIT TO AFTER JULY, 2005. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

NOTE 3: FOR PURPOSES OF ANALYSIS, FROM MARCH, 1996 THROUGH FEBRUARY, 2010, ASSUME THAT UP TO 200 MILLION CUBIC FEET PER DAY OF THE PHASE III TRANSPORTATION CAPACITY WILL BE AVAILABLE TO FPL. FOR THESE VOLUMES, ASSUME THE TRANSPORTATION DEMAND CHARGE IS A SUNK COST. FROM MARCH, 2010 FORWARD, ASSUME THAT THESE PHASE III VOLUMES ARE STILL AVAILABLE, HOWEVER, 100% OF THE DELIVERED NATURAL GAS PRICE IS VARIABLE. (i.e. THE TRANSPORTATION DEMAND CHARGE IS NOT TAKE OR PAY) UNTIL A DECISION IS MADE ON THE VOLUME OF PHASE III FIRM TRANSPORTA SERVICE AND FIRM NATURAL GAS SUPPLY FPL WILL COMMIT TO AFTER FEBRUARY, 2010. THEREAFTER, THE NEW FIRM TRANSPORTATION DEMAND CHARGE WILL BECOME A SUNK COST.

PGBU - BUSINESS SYSTEMS
MARCH, 1996 - EU

1996 TO 2025 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL PRICES TO SCHERER UNIT 4 & THE MARTIN SITE, PETROLEUM COKE

MARCH 1996

FORECAST ASSUMES THAT THE MARTIN COAL PLANT WILL STARTUP IN 2004

	PLANT SCHERER UNIT 4		MARTIN PLANT: LOW SULFUR COAL				MARTIN PLANT: HIGH SULFUR COAL				PETROLEUM COKE	
	WEIGHTED AVERAGE	SPOT PRICE	WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		WEIGHTED AVERAGE NOMINAL		SPOT PRICE NOMINAL		NOMINAL	
YEAR	$/MMBTU	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU	$/TON	$/MMBTU
1996	$1.75	$1.54	$45.51	$1.87	$45.51	$1.87	$44.19	$1.92	$44.19	$1.92	$30.80	$1.10
1997	$1.76	$1.56	$46.52	$1.91	$46.52	$1.91	$45.17	$1.96	$45.17	$1.96	$31.48	$1.12
1998	$1.79	$1.59	$47.52	$1.95	$47.52	$1.95	$46.14	$2.01	$46.14	$2.01	$32.16	$1.15
1999	$1.81	$1.61	$48.58	$1.99	$48.58	$1.99	$47.16	$2.05	$47.16	$2.05	$32.87	$1.17
2000	$1.82	$1.64	$49.69	$2.04	$49.69	$2.04	$48.24	$2.10	$48.24	$2.10	$33.62	$1.20
2001	$1.88	$1.67	$50.91	$2.09	$50.91	$2.09	$49.43	$2.15	$49.43	$2.15	$34.45	$1.23
2002	$1.91	$1.70	$52.20	$2.14	$52.20	$2.14	$50.68	$2.20	$50.68	$2.20	$35.32	$1.26
2003	$1.96	$1.74	$53.54	$2.19	$53.54	$2.19	$51.99	$2.26	$51.99	$2.26	$36.23	$1.29
2004	$2.00	$1.77	$54.79	$2.25	$54.91	$2.25	$53.19	$2.31	$53.31	$2.32	$37.16	$1.33
2005	$2.04	$1.80	$56.03	$2.30	$56.27	$2.31	$54.40	$2.37	$54.64	$2.38	$38.08	$1.36
2006	$2.08	$1.84	$57.39	$2.35	$57.74	$2.37	$55.71	$2.42	$56.06	$2.44	$39.06	$1.40
2007	$2.13	$1.88	$58.82	$2.41	$59.30	$2.43	$57.10	$2.48	$57.58	$2.50	$40.13	$1.43
2008	$2.18	$1.92	$60.51	$2.48	$60.85	$2.49	$58.71	$2.55	$59.08	$2.57	$41.18	$1.47
2009	$1.96	$1.96	$61.91	$2.54	$62.39	$2.56	$60.07	$2.61	$60.57	$2.63	$42.22	$1.51
2010	$2.00	$2.00	$63.34	$2.60	$63.95	$2.62	$61.46	$2.67	$62.09	$2.70	$43.28	$1.55
2011	$2.04	$2.04	$64.86	$2.66	$65.61	$2.69	$62.93	$2.74	$63.70	$2.77	$44.40	$1.59
2012	$2.08	$2.08	$66.42	$2.72	$67.31	$2.76	$64.44	$2.80	$65.36	$2.84	$45.55	$1.63
2013	$2.12	$2.12	$68.36	$2.80	$69.08	$2.83	$66.29	$2.88	$67.07	$2.92	$46.75	$1.67
2014	$2.17	$2.17	$70.01	$2.87	$70.89	$2.91	$67.90	$2.95	$68.83	$2.99	$47.97	$1.71
2015	$2.22	$2.22	$71.79	$2.94	$72.82	$2.98	$69.62	$3.03	$70.70	$3.07	$49.28	$1.76
2016	$2.27	$2.27	$73.60	$3.02	$74.80	$3.07	$71.37	$3.10	$72.63	$3.16	$50.62	$1.81
2017	$2.31	$2.31	$75.33	$3.09	$76.72	$3.14	$73.05	$3.18	$74.49	$3.24	$51.92	$1.85
2018	$2.36	$2.36	$77.43	$3.17	$78.61	$3.22	$75.06	$3.26	$76.32	$3.32	$53.19	$1.90
2019	$2.41	$2.41	$79.18	$3.25	$80.52	$3.30	$76.75	$3.34	$78.18	$3.40	$54.49	$1.95
2020	$2.46	$2.46	$80.97	$3.32	$82.48	$3.38	$78.49	$3.41	$80.08	$3.48	$55.82	$1.99
2021	$2.51	$2.51	$82.81	$3.39	$84.49	$3.46	$80.27	$3.49	$82.03	$3.57	$57.17	$2.04
2022	$2.56	$2.56	$84.69	$3.47	$86.55	$3.55	$82.09	$3.57	$84.03	$3.65	$58.57	$2.09
2023	$2.61	$2.61	$87.01	$3.57	$88.65	$3.63	$84.30	$3.67	$86.07	$3.74	$59.99	$2.14
2024	$2.66	$2.67	$88.98	$3.65	$90.81	$3.72	$86.22	$3.75	$88.17	$3.83	$61.45	$2.19
2025	$2.72	$2.72	$91.00	$3.73	$93.02	$3.81	$88.17	$3.83	$90.31	$3.93	$62.95	$2.25

PGBU - BUSINESS SYSTEMS
MARCH, 1996 - EU

1996 TO 2025 FPL LONG-TERM BASE CASE FOSSIL FUEL PRICE FORECAST

DELIVERED NOMINAL DOLLAR COAL TO SJRPP, ORIMULSION TO MANATEE & MARTIN

MARCH 1996 DELIVERED ST. JOHNS RIVER POWER PARK FUEL PRICES (INCLUDES VARIABLE O & M COSTS)

YEAR	CONTRACT COAL PRICE NOMINAL $/TON	CONTRACT COAL PRICE NOMINAL $/MMBTU	SPOT COAL PRICE NOMINAL $/TON	SPOT COAL PRICE NOMINAL $/MMBTU	WEIGHTED AVERAGE COAL PRICE NOMINAL $/TON	WEIGHTED AVERAGE COAL PRICE NOMINAL $/MMBTU
1996	$39.83	$1.63	$34.75	$1.42	$37.68	$1.54
1997	$41.06	$1.68	$35.60	$1.46	$40.15	$1.65
1998	$40.30	$1.65	$36.43	$1.49	$39.45	$1.62
1999	$40.91	$1.68	$37.32	$1.53	$39.97	$1.64
2000	$40.54	$1.67	$38.25	$1.57	$39.85	$1.64
2001	$41.45	$1.70	$39.28	$1.61	$40.77	$1.67
2002	$40.92	$1.71	$40.36	$1.65	$40.75	$1.69
2003	$41.34	$1.69	$41.49	$1.70	$41.39	$1.70
2004	$42.34	$1.74	$42.63	$1.75	$42.43	$1.74
2005	$43.37	$1.78	$43.78	$1.79	$43.49	$1.78
2006	$41.95	$1.72	$45.01	$1.84	$42.87	$1.76
2007	$42.99	$1.76	$46.32	$1.90	$43.98	$1.80
2008	$47.18	$1.93	$47.61	$1.95	$47.31	$1.94
2009	$48.31	$1.98	$48.91	$2.00	$48.49	$1.99
2010	$49.46	$2.03	$50.22	$2.06	$49.69	$2.04
2011	$50.69	$2.08	$51.60	$2.11	$50.97	$2.09
2012	$51.95	$2.13	$53.04	$2.17	$52.28	$2.14
2013	$53.67	$2.20	$54.52	$2.23	$53.92	$2.21
2014	$55.00	$2.25	$56.04	$2.30	$55.31	$2.27
2015	$56.44	$2.31	$57.65	$2.36	$56.80	$2.33
2016	$57.90	$2.37	$59.32	$2.43	$58.33	$2.39
2017	$59.29	$2.43	$60.92	$2.50	$59.78	$2.45
2018	$61.17	$2.51	$62.51	$2.56	$61.57	$2.52
2019	$62.58	$2.56	$64.11	$2.63	$63.04	$2.58
2020	$64.02	$2.62	$65.76	$2.69	$64.54	$2.65
2021	$65.50	$2.68	$67.44	$2.76	$66.08	$2.71
2022	$67.02	$2.75	$69.16	$2.83	$67.66	$2.77
2023	$69.08	$2.83	$70.93	$2.91	$69.63	$2.85
2024	$70.67	$2.90	$72.74	$2.98	$71.29	$2.92
2025	$72.30	$2.96	$74.59	$3.06	$72.99	$2.99

DELIVERED NOMINAL ORIMULSION PRICES
EXCESS PRICE INCLUDES VARIABLE O & M EXPENSES

YEAR	PETROLEUM COKE NOMINAL $/TON	PETROLEUM COKE NOMINAL $/MMBTU	WEIGHTED AVERAGE FUEL PRICE NOMINAL $/TON	WEIGHTED AVERAGE FUEL PRICE NOMINAL $/MMBTU	MANATEE BASE PRICE $/MMBTU	MANATEE EXCESS PRICE $/MMBTU	MARTIN BASE PRICE $/MMBTU	MARTIN EXCESS PRICE $/MMBTU
1996			$37.68	$1.54				
1997	$31.48	$1.12	$38.42	$1.54				
1998	$32.16	$1.15	$37.99	$1.52	$1.73	$1.37		
1999	$32.87	$1.17	$38.55	$1.55	$1.76	$1.40	$1.89	$1.56
2000	$33.62	$1.20	$38.60	$1.55	$1.75	$1.44	$1.88	$1.62
2001	$34.45	$1.23	$39.51	$1.59	$1.79	$1.48	$1.92	$1.66
2002	$35.32	$1.26	$39.66	$1.61	$1.79	$1.52	$1.93	$1.71
2003	$36.23	$1.29	$40.36	$1.62	$1.78	$1.57	$1.92	$1.75
2004	$37.16	$1.33	$41.37	$1.66	$1.82	$1.61	$1.97	$1.81
2005	$38.08	$1.36	$42.41	$1.70	$1.87	$1.66	$2.02	$1.86
2006	$39.08	$1.40	$42.11	$1.68	$1.81	$1.70	$1.97	$1.91
2007	$40.13	$1.43	$43.21	$1.73	$1.85	$1.75	$2.01	$1.97
2008	$41.18	$1.47	$46.08	$1.85	$2.03	$1.80	$2.19	$2.03
2009	$42.22	$1.51	$47.23	$1.89	$2.08	$1.86	$2.24	$2.08
2010	$43.28	$1.55	$48.41	$1.94	$2.12	$1.91	$2.30	$2.14
2011	$44.40	$1.59	$49.65	$1.99	$2.18	$1.96	$2.35	$2.20
2012	$45.55	$1.63	$50.93	$2.04	$2.23	$2.02	$2.41	$2.26
2013	$46.75	$1.67	$52.49	$2.10	$2.30	$2.08	$2.49	$2.33
2014	$47.97	$1.71	$53.84	$2.16	$2.36	$2.14	$2.55	$2.39
2015	$49.28	$1.76	$55.30	$2.21	$2.42	$2.21	$2.62	$2.46
2016	$50.62	$1.81	$56.78	$2.27	$2.48	$2.27	$2.68	$2.54
2017	$51.92	$1.85	$58.20	$2.33	$2.54	$2.33	$2.75	$2.61
2018	$53.19	$1.90	$59.89	$2.40	$2.62	$2.40	$2.83	$2.68
2019	$54.49	$1.95	$61.33	$2.46	$2.62	$2.40	$2.90	$2.75
2020	$55.82	$1.99	$62.80	$2.51	$2.62	$2.40	$2.96	$2.82
2021	$57.17	$2.04	$64.30	$2.58	$2.62	$2.40	$2.96	$2.82
2022	$58.57	$2.09	$65.84	$2.64	$2.62	$2.40	$2.96	$2.82
2023	$59.99	$2.14	$67.71	$2.71	$2.62	$2.40	$2.96	$2.82
2024	$61.45	$2.19	$69.32	$2.78	$2.62	$2.40	$2.96	$2.82
2025	$62.95	$2.25	$70.98	$2.84	$2.62	$2.40	$2.96	$2.82

PGBU-BUSINESS SYSTEMS
MARCH, 1996 - EU

#38

CENTS PER KWH COMPARISON

QUALIFYING FACILITIES

YEAR	CAPACITY CENTS/KWH	ENERGY CENTS/KW	TOTAL CENTS/KWH
1993	1.17	2.77	3.94
1994	1.23	3.29	4.52
1995	1.30	3.75	5.05
1996	1.37	4.22	5.59
1997	1.44	4.70	6.14
1998	1.52	5.18	6.70
1999	1.60	5.66	7.26
2000	1.69	6.17	7.86

QF CAPACITY PAYMENTS BASED ON 80% RISK FACTOR
QF ENERGY PAYMENTS BASED ON ENERGY
COST AT MARTIN 3 & 4

SOUTHERN

CAPACITY CENTS/KWH	ENERGY CENTS/KW	TOTAL CENTS/KWH
2.50	2.25	4.75
2.47	2.53	5.00
2.25	2.50	4.75
2.23	2.60	4.83
2.22	2.77	4.99
2.21	3.13	5.34
2.21	3.15	5.36
2.20	3.40	5.60

SOUTHERN CAPACITY PAYMENTS BASED ON 90% CAPACITY FACTOR

LAUDERDALE REPOWERING

YEAR	CAPACITY CENTS/KWH	ENERGY CENTS/KW	TOTAL CENTS/KWH
1993	2.03	2.83	4.86
1994	1.92	3.27	5.19
1995	1.83	3.73	5.56
1996	1.99	4.20	6.19
1997	1.91	4.68	6.59
1998	1.99	5.16	7.15
1999	1.94	5.64	7.58
2000	1.96	6.14	8.10

MARTIN 3

CAPACITY CENTS/KWH	ENERGY CENTS/KWH	TOTAL CENTS/KWH
3.23	3.29	6.52
3.09	3.75	6.84
3.47	4.22	7.69
3.31	4.70	8.02
3.48	5.18	8.66
3.37	5.66	9.03
3.41	6.17	9.58

MARTIN 4

YEAR	CAPACITY CENTS/KWH	ENERGY CENTS/KW	TOTAL CENTS/KWH
1993			
1994			
1995	3.44	3.75	7.19
1996	3.95	4.22	8.17
1997	3.74	4.70	8.44
1998	3.92	5.18	9.10
1999	3.76	5.66	9.42
2000	3.78	6.17	9.95

MARTIN 5, 6 IGCC

CAPACITY CENTS/KWH	ENERGY CENTS/KWH	TOTAL CENTS/KWH
8.77	2.02	10.79
8.58	2.16	10.74
8.32	2.31	10.63
8.07	2.48	10.55
7.81	2.65	10.46

Florida Power & Light Company
Docket Nos. 890973-EI & 890974-EI
FPL Witness: S. S. Waters
Exhibit No. ______

EXHIBIT NO. 4

DOCKET NO.: 960409-EI

WITNESS: WATERS

DESCRIPTION: CHARLES BLACK PRESENTATION REGARDING ECONOMIC JUSTIFICATION FOR IGCC

Ex. 33

2.3 A Utility's Perspective of the Market for IGCC

CONTRACT INFORMATION

Cooperative Agreement	DE-FC21-91MC27363
Contractor	Tampa Electric Company P.O. Box 111, Tampa FL 33601 (813) 228-1767
Contractor Project Manager	Charles R. Black
Principal Investigators	Charles R. Black
METC Project Manager	Nelson F. Rekos, Jr.
Period of Performance	January 1, 1996 to December 31, 1997

INTRODUCTION

I would like to discuss our utility's view of the Market for Integration Gasification Combined Cycle (IGCC) power plants and share with you some of the experiences we have had with our Integrated Gasification Combined Cycle Power Plant Project, Polk Unit #1.

We have found that not only is the technology different from what most U. S. utilities are accustomed to, but also that the non-technical issues or business issues, such as contracting, project management and contract administration also have different requirements. During this conference you will hear many presentations on the status of the technical issues associated with IGCC technology. Therefore, I will focus my remarks on the non-technical or business issues that are vital to the successful commercialization of this technology.

We believe these business issues must be successfully addressed by both the utilities and the technology suppliers in order for integrated gasification combined cycle power plants (IGCC) to achieve commercial success.

In order to understand some of the issues we have experienced, it will be helpful to understand how our project is configured and our current status.

PARTICIPANTS

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC serves about 470,000 Customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC owns five generating stations: two are coal-fired (2852MW) two are oil-fired (253MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

TECO Power Services (TPS) is a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS currently owns, and operates a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a twenty year power sales agreement.

TPS is responsible for the overall project management for the DOE portion of this IGCC

EXHIBIT
4
6-16-96

This will lead to the commercial operation of the CT in July 1995 and the IGCC unit in July 1996.

BUSINESS ISSUES
ECONOMIC JUSTIFICATION

The first business issue any utility has to deal with in implementing a new generating addition is the issue of economic justification. The three basic driving forces in the economic justification of any technology are its fuel cost relative to other technologies, its capital cost, and its efficiency.

I believe, in the short-term U. S. market, that IGCC's primary competition is natural gas-fired combined cycle technology. I believe that in order for IGCC to compete on a commercial basis, that natural gas prices have to rise relative to coal prices, and that the capital cost of the technology must come down. While this statement may seem to be somewhat obvious, it raises two interesting points.

The first is that while the relative pricing of natural gas and coal is not generally within the technology supplier's control, the capital cost is. The reduction of capital cost represents a major challenge for the technology suppliers in order for this technology to become commercialized.

The second point is that the improvements being achieved with IGCC efficiencies probably won't help it outperform the effects of natural gas pricing. This is due to the fact that the combined cycle portion of the IGCC technology is experiencing the most significant improvements in efficiency. While certain improvements in coal gasification and integration are being made, they potentially will be overshadowed by improvements in combustion turbine/combined cycle technology. Combustion Turbine/Combined Cycle improvements will apply to natural gas-fired units as well as IGCC units. Therefore, I believe the relative efficiencies of these technologies will continue to closely track.

I do see, however, a significant advantage for IGCC technology compared to conventional pulverized coal-fired units. As IGCC efficiencies continue to improve, combined with their environmentally superior performance, I believe that IGCC will be the "technology of choice" for utilities that install new coal-fired generation.

We have achieved economic justification of our project by virtue of the DOE's funding of $120 million awarded in Round III of their Clean Coal Technology Program. This program provides the bridge between current technology economics and those of the future. And Tampa Electric is pleased to be taking a leadership position in furthering the IGCC knowledge base.

SITING

The next major issue that a utility must address after a technology decision has been made is that of siting. Siting of coal-fired generation is a major issue that must be addressed in order to commercialize IGCC or any other coal-based technology. Successful siting is a primary responsibility of the utility. For the Polk Power Station, we employed a proactive approach with local environmentalists and the local communities.

By late 1989, we had formed an independent citizen's task force made up of 17 people representing environmentalists, educators, economists and community leaders, to help guide that search.

Some of the various groups who had members on the task force were: The National Audubon Society, Florida Audubon Society, 1,000 Friends of Florida, Sierra Club, The Hillsborough Environmental Coalition, and others. We made sure that at least half of the group was comprised of environmentalists. We knew that protecting the environment would be the number one priority in selecting the plant's technology and site.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that one true and correct copy of the Deposition Transcript and Exhibits of Mr. Samuel S. Waters 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:

Florida Industrial Power
Users Group
Vicki Kaufman, Esquire
117 South Gadsden Street
Tallahassee, FL 32301

Office of Public Counsel
John Roger Howe, Esquire
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111 W. Madison Street
Tallahassee, FL 32399-1400

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Tampa Electric Company
Ms. Jana Hathorne *
Regulatory Affairs Department
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* Furnished to Mr. Willis by hand delivery.

Robert V. Elias

ROBERT V. ELIAS
Chief, Bureau Electric and Gas

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