84

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for Determination of Need for an Intrastate Natural Gas Pipeline by SunShine Pipeline Partners	Docket No.: 920807-GP Filed: March 8, 1993

DIRECT TESTIMONY

OF

JUDAH L. ROSE

FOR

SUNSHINE PIPELINE PARTNERS

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ON BEHALF OF THE SUNSHINE PIPELINE PARTNERS

Q. Please state your name and business address.

A. My name is Judah L. Rose. My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

Q. By whom and in what capacity are you employed?

A. I am employed as a Project Manager at ICF Resources, Incorporated, an energy consulting firm in Washington, D.C. specializing in economic, strategic and environmental policy analysis. ICF Resources has an electric utility practice specializing in industry issues such as capacity expansion planning, demand side management, fuel procurement, acid rain, and global climate change. ICF Resources also has practices in the coal, natural gas and oil industries.

At ICF Resources, I specialize in economic, technology, business strategy, and public policy issues affecting the electric utility industry, and the industries supplying fuel to electric utilities - particularly the coal and natural gas industries.

I also am currently working for the Electric Power Research Institute (EPRI) and Japan's Central Research Institute of the Electric Power Industry (CRIEPI) on global climate change and improvements in the tools and computer based methodologies available to electric utilities for evaluating new powerplant and Demand Side Management options. This work is the second phase of climate analysis for EPRI. In the first phase, I directed six case studies of electric utilities including demand projection studies using such EPRI demand models as the Hourly Electric Load Model (HELM).

I am also working on several projects related to the natural gas industry. For example, I am coordinating the construction of a new computer based model of the U.S. natural gas industry for the U.S. Department of Energy's Morgantown Energy Technology Center. This model, known as the Gas System Analysis Model (GSAM) addresses issues related to gas extraction and production, pipeline transmission, and demand. This model will also address the competition between gas and oil, including residual and distillate oil and the competition between gas and coal.

Q. **Have you testified previously in Florida?**

A. Yes. In December of 1992, I testified before the Florida Department of Environmental Regulation (DER) on the regulation of new powerplant construction. This testimony was on behalf of the Florida Electric Power Coordinating Group.

Q. Please describe your educational background and professional experience.

A. I have a Bachelors of Science in Economics from the Massachusetts Institute of Technology, and a Masters of Public Policy from Harvard University. I have been working on energy and environmental issues for sixteen years, since 1977, and I have been employed by ICF Resources since 1982. Prior to working at ICF Resources, I worked for the National Economic Research Associates (NERA), the MIT Energy Impacts Project, and the Israel Ministry of Energy.

Q. By whom and for what purpose were you retained?

A. I was retained by the SunShine Pipeline Partners to assess the need of Florida electric utilities and other power generators for additional gas pipeline capacity during 2000 and 2010.

Q. What are the potential sources of increased demand for gas pipeline capacity in the electric utility industry?

A. New powerplants that use natural gas and existing powerplants that might switch from oil to gas will in many cases require additional natural gas pipeline capacity.

Q. What steps did you take to assess the potential from new powerplants?

A. To evaluate potential pipeline capacity required from new powerplants, the first step is to estimate the potential demand for new powerplants. This step requires both an assessment of the potential growth in Florida electricity demand considering efficiency and conservation gains and likely retirements of existing powerplants. The second step is to determine whether these new powerplants will use gas and require new pipeline capacity. This step requires a comparison of the costs of a firm gas supply and other new powerplant options, and consideration of other factors affecting fuel choice for new powerplants.

Q. How did you assess the potential from existing powerplants?

A. In the case of existing powerplants, the first step is to determine whether it is less costly to use natural gas or oil. Because I am assessing the need for new pipeline capacity, the comparison is between a firm gas supply and oil. This requires projection of oil and natural gas prices. The second step is to determine whether other factors, such as acid rain regulations, might affect the choice between oil and gas.

Q. **Please summarize your testimony.**

A. There are five parts to my testimony. Section I presents a range of forecasts from several sources of the long-term growth in demand for electricity in Florida. These forecasts indicate that generation requirements in Florida are likely to grow substantially and that new powerplants will be required to meet this demand growth.

Section II discusses fuel choice for the new powerplants that will be built to meet incremental generation requirements. Based on forecasts from Florida utilities and ICF Resources' forecasts, we believe that there is an important role for natural gas in meeting future demand for power.

Section III describes the potential for increased use of natural gas at existing electric powerplants that currently consume oil. Many existing powerplants in Florida, now consuming oil, may switch to natural gas, further increasing the growth in demand for natural gas from the electric utility industry.

Section IV estimates future demand for natural gas pipeline capacity from electric utilities . ICF Resources expects that the demand increase will exceed the size of the proposed SunShine pipeline. Section V briefly summarizes my findings.

Q. **Please summarize your conclusions.**

A. The growth in electric generation demand in Florida will justify more pipeline capacity for new powerplants. In addition, existing powerplants burning oil will demand firm gas supplies requiring more pipeline capacity.

The extent of the demand for new powerplants depends on (1) the growth rate in electricity demand, (2) whether the new plants will choose gas as their primary fuel, and (3) whether they want firm pipeline capacity. My investigation of forecasts by the Florida Electric Power Coordinating Group's (FEPCG) 1992 Ten Year Plan and of those announced by utilities, supplemented by a review of historical electricity demand growth and sensitivity projections that I developed, indicates that even if future conditions tend to minimize demand growth, significant electricity demand growth is still likely to occur by 2000 and even more by 2010.

Florida utilities expect that most (about 67 percent) of their new powerplants will be gas-fired. My analysis of the economics of new powerplant options indicates that even using conservative assumptions about fuel choice, a large share of new powerplants will be gas-fired and need new capacity.

The extent to which existing oil/gas plants in Florida will prefer gas and seek firm gas supply depends primarily on gas and residual oil prices. The decision will also be influenced by acid rain regulations, which favor gas use over oil, and potential new federal energy taxes, which also favor gas use over oil use. My analysis of the economics indicates a large portion of existing plants will use gas and seek firm pipeline capacity.

I estimated demand for gas pipelines in Florida using alternative electricity demand growth scenarios. Using the FEPCG's 1992 Ten Year Plan as the basis for electricity growth rates results in total demand for pipeline capacity in 2010 of 5.0 Bcf/day. This result is 3.5 Bcf/day greater than the 1.5 Bcf/day of capacity that will be available if Phase III additions to Florida Gas Transmission are approved. In 2000, total demand will be 3.8 Bcf/day, or 2.3 Bcf/day above available supply. Thus, even in 2000, the demand for pipeline capacity will be much larger than the available capacity even if the proposed SunShine pipeline is built. All my estimates make the following conservative assumptions: (1) no growth in non-electric demand for gas; (2) conservative estimates of the share of plants choosing firm gas supply; and (3) no retirement of existing nuclear powerplants until after 2010.

Even when I used assumptions that result in low electricity demand growth and low demand for pipeline capacity, demand for pipeline capacity exceeds supply by 2.0 Bcf/day in 2000 and 2.7 Bcf/day in 2010. Thus, even if the SunShine pipeline is added, demand will exceed supply.

Finally, greater growth in electricity demand might require additional pipeline capacity. Keeping all growth factors except electricity demand growth constant at historical levels, demand for capacity could exceed supply in 2000 by 2.7 Bcf/day and in 2010 by 4.5 Bcf/day.

SECTION I - LONG-TERM ELECTRICITY DEMAND

Q. **Why did you examine long-term electricity demand in Florida?**

A. If Florida electricity demand increases over time, more powerplants will be needed. These new power-plants may consume natural gas and require more gas pipeline capacity.

Q. **How did you assess the potential for future demand growth?**

A. I reviewed two demand growth forecasts, one developed by FEPCG (which is reviewed by the Florida Public Service Commission), and a second by Florida electric utilities. I then reviewed historical electricity demand growth in Florida. Finally, since the demand forecasts developed by the FEPCG and contained in the 1992 Ten Year Plan did not include sensitivity studies, I developed a range of demand projections based upon this study to provide perspective on relevant uncertainties in the forecast. I developed these projections using demand models developed by EPRI, and using public forecasts of important factors affecting electricity demand, such as population growth.

Q. **Please briefly summarize the results of this assessment.**

A. The Florida projections of demand growth indicated that there was likely to be significant growth in demand. Florida electricity use has been growing very quickly. Both the state's forecasts and my sensitivity tests of demand, including the one developed using the lowest available forecasts of population growth and associated inputs, indicated that there was likely to be significant growth in demand. With this significant growth in electricity demand, there should be significant demand for new generating capacity.

Q. What forecast of electricity demand is available from the State of Florida?

A. FEPCG's "*1992 Ten Year Plan - State of Florida*" contains a forecast of electricity demand growth in the State of Florida.

Q. How is this forecast developed?

A. Each utility develops a forecast of electricity demand. These forecasts are then used to develop a statewide forecast by the Florida Electric Power Coordinating Group, which is then reviewed by the Florida Public Service Commission.

Q. Does this forecast receive regulatory review?

A. Yes. In the past there have been both workshops and regulatory hearings regarding these submittals.

Q. **What is the forecast of electricity demand growth in the 1992 Ten Year Plan?**

A. The composite forecast is that electricity demand in the State of Florida will grow at a rate of 2.6 percent per year between 1992 and 2001.

Q. **Is this forecast of electricity demand referring to peak or energy sales demand?**

A. The FEPCG's forecast mentioned above refers to energy sales. The State of Florida also forecasts peak demand; and it is forecast to grow at practically the same rate as energy sales. In the remainder of my testimony, when I refer to electricity demand I am referring to energy sales demand and I assume peak demand increases at the same rate as energy sales.

Q. **Are you aware of any other public forecasts of electricity demand in the State of Florida?**

A. Yes. Florida utilities annually provide forecasts of electricity demand for a ten year period to the Southeastern Electric Reliability Council (SERC). This forecast is used by SERC to ensure reliability of electricity supply. Florida utilities estimate that electricity demand in the Florida subregion of SERC will grow at an average annual rate of 2.7 percent per year between 1991 and 2001.

Q. **How do these forecasts compare to projected growth rates in other regions of the U.S.?**

A. Florida's forecast is higher than all but one North American Electric Reliability Council (NERC) region nationally; the Arizona/New Mexico subregion forecasts equal growth. The average growth rate across the U.S. is projected to be 30 percent less, at 1.9 percent per year.

Q. **What additional evidence exists regarding utility expectations regarding future growth in electricity demand?**

A. Electricity demand growth requires Florida utilities to build new powerplants or purchase capacity from independent power producers. Florida utilities also annually provide plans for new capacity additions. These plans indicate that Peninsular Florida (all major Florida electric utilities except Gulf Power) expect significant electricity demand growth, and hence, they plan to add about 9,900 megawatts of generation capacity between 1992 and 2001 including the capacity that cogenerators and independent power producers will sell to utilities. This represents a 30 percent increase over capacity at the end of 1991 (about 33,000 megawatts).

Q. **How do these projected growth rates compare to historical trends?**

A. Forecasted growth rates of 2.6 to 2.7 percent are considerably lower than recent history.

Q. **What was the historical growth in Florida electricity demand between 1980 and 1991?**

A. Florida's use of electricity has grown faster than almost any other state. In Florida between 1980 and 1991, electricity sales demand grew at a rate of 4.2 percent per year. In comparison, electricity demand in the U.S. grew at 2.4 percent per year. In only two states (Nevada and Wyoming) electricity demand grew faster than in Florida over the same period.

Both residential and commercial electricity demand grew especially fast during this period, about 4.7 and 7.3 percent, respectively. Industrial demand declined slightly.

Q. **Why is the electricity demand growth forecast of Florida and Florida electric utilities less than historical growth?**

A. The most important factor affecting growth rates is the forecasted decrease in the growth rate in the number of customers. This can be explained by forecasts that population growth will slow. The

State of Florida Governor's Office is forecasting in its medium case that population will grow at an annual average rate of 1.7 percent between 1990 and 2010, a 40 percent decrease from the rate of growth between 1980 and 1991.

Q. **Did you have access to public sensitivity studies that account for uncertainties in these forecasts?**

A. No. The forecasts of demand growth contained in the FEPCG's Ten Year Plan was not accompanied by sensitivity studies. To develop a range of forecasts that encompassed relevant uncertainties in key assumptions, I tested the effect of factors such as population growth on electricity demand growth in Florida.

Q. **Why are sensitivities important to your analysis?**

A. I wanted to see whether there would be large enough demand for the SunShine pipeline even under demand conditions that would result if key parameters like population growth were at the low end of the plausible range.

Q. **Please describe your methodology for developing these sensitivity studies.**

A. I used demand models developed by EPRI. Using public data and projections, I calibrated the models to within a narrow range of the forecasts of the FEPCG and Florida utilities. I then tested the sensitivity of results using public projections of population and other inputs.

Q. **What electricity demand models did you use?**

A. I used EPRI's demand models that have gained industry-wide acceptance : the Residential End-Use Energy Projection System (REEPS), the Commercial Sector End-Use Planning System (COMMEND), and the Industrial End-Use Forecasting System (INFORM). These systems model electricity demand on an end-use specific basis. For example, the residential model projects the saturation and the intensity of use of various types of end-use systems such as air conditioning, cooking and water heating. The REEPS model also projects the change over time in the efficiency of appliances due to new technology.

Q. **What data sources did you use to calibrate your model?**

A. I used a wide variety of EPRI and other sources of data to calibrate the models to Florida conditions.

Q. **Which sector is the largest consumer of electricity in Florida?**

A. The residential sector was the largest and most important sector, accounting for 50 percent of the total 1990 demand for electricity in Florida.

Commercial was the second largest accounting for 39 percent. Industrial was the smallest and accounted for 11 percent.

Q. **What did you identify as the most important uncertainties in your analysis of residential demand for electricity?**

A. The most important uncertainties affecting residential electricity demand are population, household and customer growth and energy efficiency.

Q. **How fast did Florida's population grow between 1980 and 1991?**

A. Florida's population has been growing faster than nearly all other states. Between 1980 and 1991, Florida's population grew at an annual average rate of 2.85 percent per year. In contrast, the U.S. total population grew at a 1.0 percent rate. Further, only three states (Alaska, Nevada and Arizona) had a faster rate of growth in population.

Q. **What inputs did you use for population growth in your sensitivity studies?**

A. I used two public projections of population both indicating that Florida population growth will slow relative to 1980 to 1991 levels. In the case designed to approximate the FEPCG and Florida utility projections of electricity demand, I used the Florida State Governor's Office forecast of 1.7 percent between 1990 and 2010. In the low sensitivity case, I used the lowest public forecast of population growth which I could find: the University of Florida Bureau of Economic and Business Research (BEBR), February 1992 low projection for Florida population growth between 1990 and 2010. In this projection, population grew 1.1 percent per year.

In the high growth scenario, I assumed that population growth would continue at the same rate as during 1980 to 1991 historical levels.

Q. **What was the range of demand growth in your residential sensitivity projections?**

A. Residential electricity sales increased at rates from 1.7 to 3.6 percent in the low and in the high case, respectively.

Q. **What did you identify as the important uncertainty in your analysis of commercial demand for electricity?**

A. The most important uncertainty affecting commercial electricity demand is the rate of increased commercial sector economic activity which can be measured by commercial employment growth and energy efficiency.

Q. How fast did Florida's commercial employment grow between 1980 and 1991?

A. Between 1980 and 1990, commercial employment increased at a rate of 4.6 percent, 60 percent faster than population.

Q. What inputs did you use for this factor in your sensitivity studies?

A. The State of Florida Governor's Office is forecasting that commercial employment will grow between 1990 and 2010 at the same rate as population. We used this assumption together with the State of Florida Governor's Office population forecast, in the case designed to approximate the FEPCG and Florida utility projections of electricity demand. In the low growth case, we used the BEBR projection of population together with the assumption that commercial employment would increase at the same rate as population.

In the high growth scenario, we assumed that the historical relationship between population and commercial employment was maintained and assumed that the historical rates of population growth would continue.

Q. What was the range of growth rates in your commercial demand projections?

A. Commercial electricity sales growth increased at rates from 1.6 to 4.5 percent in the low and in the high cases, respectively.

Q. What did you identify as the most important uncertainty in your analysis of industrial demand for electricity?

A. The value of manufactured products was the most important variable affecting the industrial demand forecast.

Q. What inputs did you use for this factor in your sensitivity studies?

A: I used two forecasts of the growth in the value of manufactured products were used. The first was from the U.S. Bureau of Labor Statistics (2.7 percent growth per year) which was used in the case designed to approximate the FEPCG and Florida utility projections of electricity demand and in the low case. The second was from the U.S. Department of Energy's Energy Information Administration (3.1 percent growth per year) which was used in the high case.

Q. What was the range of growth rates in your industrial forecasts?

A. Industrial electricity sales were projected to increase at a rate of 2.3 to 2.5 percent.

Q. What projections of <u>total</u> electricity demand growth in Florida did you develop using the EPRI models?

A. The projections of growth between 1990 and 2010 of total electricity demand were 1.7 percent per year in the low case and 3.8 percent per year in the high case.

Q. Are conservation effects included in these sensitivity projections?

A. Yes. The EPRI models account for improvements in efficiency of electric appliances and equipment purchased by consumers on their own for new households or as their old appliances are retired. This helps explain why the forecasts of future growth in Florida and elsewhere developed using these models are less than historical growth rates. This very significant increase in efficiency means that there is little more economic conservation that utilities can easily achieve via additional demand-side management energy conservation programs. This explains why our sensitivities are consistent with the FEPCG 1992 Ten Year Plan forecast that includes all planned DSM effects.

Q. What conclusions did you develop based on your analysis of electricity demand?

A. Demand for electricity in Florida is likely to grow substantially through to 2010. If demand grows at the rate forecast in the Ten Year Plan through to 2010, electricity generation requirements will exceed 1991 levels by 26 percent in 2000, and by 63 percent in 2010 (See Exhibit A).

Demand growth could be explosive. If demand grows at the rate in the high sensitivity case, that is, if recent trends continue, generation requirements could be 40 percent higher in 2000 relative to 1991, and 103 percent higher by 2010.

Even under the most conservative assumptions tested, demand growth would be substantial: 17 percent by 2000 and 37 percent by 2010.

Q. What are the implications of this demand growth?

A. Florida will need to build additional powerplants to meet this demand.

Q. In addition to demand growth, what else affects the demand for new powerplants?

A. More new powerplants will be needed if Florida utilities retire existing powerplants.

Q. How much powerplant capacity in Florida will be retired by 2010?

A. I assume that no coal or nuclear powerplants in the state will retire before 2010. I make this assumption to be conservative in my estimates of pipeline demand. If Turkey Point nuclear powerplant Units 3 and 4 retire when their licenses expire in 2007, gas pipeline demand will be 0.2 to 0.3 Bcf/day higher than shown here in all 2010 scenarios.

I assume that 800 megawatts of existing oil/gas steam capacity (about 4 percent of the total amount of such capacity in Florida) and most combustion turbines will be retired by 2010. However, the impacts of these retirements is relatively small.

SECTION II - FUEL CHOICE AT NEW FLORIDA ELECTRIC POWERPLANTS

Q. **Why did you examine fuel choice at new powerplants?**

A. New powerplants will be required to meet the coming growth in electricity demand in Florida. These powerplants could be natural gas fueled and require new pipeline capacity.

Q. **How did you assess fuel choice at new powerplants?**

A. I reviewed utility-announced plans for new powerplants to see what fuels they were choosing. I then analyzed the economics of various new powerplant options including the cost and non-cost factors affecting fuel choice. This enabled me to see why utilities had made the choices they had, and to develop a conservative estimate of the amount of new natural gas pipeline capacity required to serve these plants.

Q. **What did you conclude from your assessment?**

A. Utilities expect that two-thirds of the new powerplant capacity in Florida will be natural gas-fired. My conservative estimate of the amount of capacity that will require new pipeline capacity is no less than fifty percent. Thus, I conclude that there will be many new plants choosing gas and needing new pipeline capacity

Q. **Please outline the remainder of your testimony in this section.**

A. This section has six subsections. Section II.1 presents the fuel choice plans of Florida utilities. Section II.2 explains why the economics of gas pipeline capacity vary according to the type of powerplant (i.e. baseload, intermediate load, seasonal peaking and daily peaking powerplants). Sections II.3, II.4, II.5, and II.6 discuss the economics of fuel choice for baseload, intermediate, seasonal and daily peaking powerplants, respectively. These sections also present my conservative estimate of the choice to use gas and the need for gas pipeline capacity.

Section II.1

Q. Does public information exist regarding fuel choice plans of Florida utilities?

A. Yes. Florida electric utilities annually provide the North American Electric Reliability Council (NERC) with their estimates of future capacity additions and the fuel to be used at these new powerplants. These plans for additions extend ten years. The latest plans available extend through 2001.

Q. What fuel choices are utilities planning to make?

A. Exhibit B shows planned capacity additions for the 1992 to 2001 period. This estimate also includes non-utility owned powerplant capacity such as cogeneration and independent power producer capacity. Two-thirds of the planned capacity additions will use natural gas as the principal fuel. The remaining one third is divided among coal, oil and other fuels.

One-sixth (17 percent) of the total planned capacity will be coal-fired. One-third of the coal capacity to be added is associated with the purchase of capacity from an existing coal unit in

Georgia, Scherer #4. Another 30 percent of the total coal capacity to be added is associated with the Stanton Energy Center #2. The remainder is spread among other sites.

Other fuels, such as biomass, refuse, peat, etc., account for 8 percent of the total planned capacity. This 8 percent includes some capacity for which fuel choice is unknown. If this capacity is gas-fired, the total share of gas could be higher. Finally, 8 percent of the total will be oil projects, and nearly all of these projects are combustion turbines coming on-line by 1994 which could potentially switch to gas use at a later date.

Q. **What conclusions do you draw from these announcements?**

A. Florida utilities will use natural gas powerplants to meet most of the demand growth during the 1990s.

Q. **What did you do after reviewing utility plans for new powerplants?**

A. I reviewed the economics of fuel choice for powerplants and developed conservative estimates of what shares of new powerplant capacity would use gas and require new pipeline capacity. In order to do this, I first had to segment new powerplants into categories for which the economics were similar.

Section II.2

Q. What is the purpose of this sub-section of your testimony?

A. This sub-section discusses why I have chosen to characterize powerplants by utilization, and how I characterized them. It turns out that this characterization is important in determining how gas competes at new powerplants.

Q. Are all new electric powerplants utilized in the same manner?

A. No. Some powerplants operate at close to full capacity during the entire year, while others are used much less frequently. This is because: (1) demand for electricity varies significantly during each day, and seasonally, (2) electric power utilities attempt to nearly always meet all customer demand levels, and (3) electricity storage is costly. Utilities must plan their capacity additions in a way that optimizes the efficiency of their system at lowest cost.

Q. Does utilization affect the economics of fuel choice at new powerplants?

A. Yes. For those powerplants that are utilized less, fixed costs are spread over fewer hours, and their per unit production costs increase. These fixed costs include capital investment costs and charges, fixed gas transportation costs, and fixed O&M costs.

Some powerplants are more costly in terms of initial investment or other fixed charges than others, but are economic in some conditions because they have lower fuel and other variable costs. For example, coal powerplants often have higher capital investment costs than gas plants but lower fuel costs; coal powerplants are mostly likely to be economic if the plant's utilization is high.

Thus, high fixed cost plants are most likely to be chosen if the new powerplant is expected to operate at high utilization, and less likely if a lower utilization plant is required.

Q. **How did you group powerplants according to utilization?**

A. Often the optimum combination of powerplants involves several different types with utilization levels ranging from close to 100 percent per year down to close to 0 percent. I used four discrete categories: (1) baseload with utilization levels typically between 65 and 85 percent, (2) intermediate load, with levels typically between 45 and 60 percent, (3) seasonal peaking, with levels between 10 and 30 percent, and (4) daily peaking with levels around 1 percent.

Q. **Given the impacts of utilization on fuel choice, how did you conduct your analysis of the economics of new powerplant fuel choice?**

A. I conducted my analysis separately for each type of powerplant: (1) baseload, (2) intermediate, (3) seasonal peaking, and (4) daily peaking.

Section II.3 - Baseload Powerplants

Q. **What are the options for new baseload powerplants in Florida?**

A. The principal options for new baseload powerplants are coal, and natural gas powerplants.

In addition, there are other options such as oil powerplants and other powerplants such as wood, biomass, and municipal solid waste powerplants.

Q. **Why are municipal waste, biomass and other powerplants not principal alternatives for new baseload supply?**

A. Fuels for these kinds of powerplants are generally not developed especially for power generation, but are available as by-products of other activities.

For example, municipal solid waste is a by-product of municipal waste disposal. These supplies are limited relative to demand for power, and hence their role is limited relative to gas and coal.

Q. **Why are oil-fired powerplants not among the principal options for new baseload construction?**

A. Baseload oil powerplants are considered undesirable because of the volatility and uncertainty of oil prices. Almost no new baseload oil capacity is planned in the U.S.

Q. **How do electric utilities choose among various fuel options?**

A. Utilities consider future costs of new powerplants, as well as other factors such as the risks associated which each option. I discuss the costs of baseload coal and gas powerplant options immediately below, and then discuss several key non-cost factors.

Q. **How do electric utilities evaluate the future costs of new powerplant options?**

A. Electric utilities generally estimate the costs of new powerplant options over the life of these powerplants on a present value of revenue requirements basis. This analysis of costs considers all the costs of the powerplant, including fuel, capital charges, operation and maintenance expenses.

In order to evaluate cost effectiveness at varying utilization levels, I have presented the results of these estimates on a per kilowatthour levelized annuity price basis. This method effectively spreads the present worth of revenue requirements over the electricity a plant is expected to generate. The option with the lowest annuity price has the lowest present value of costs per kilowatthour over the accounting life of the powerplant. Costs which vary year to year (e.g. fuel costs, capital charges) are levelized; a fixed annuity is calculated which has the same present value as the varying cost price stream.

Q. **Are ranges of cost estimates typically used for power planning studies?**

A. Yes. Cost estimates are often presented in the form of a range. Utility cost estimates are uncertain since they are based on forecasts of cost factors, which are themselves uncertain. For example, estimates of the costs of new natural gas powerplants are strongly affected by future natural gas prices. Since natural gas prices are uncertain, so are the cost estimates for new natural gas powerplants.

Q. **What is the cost of new coal powerplants?**

A. Currently, new coal baseload (75% capacity factor) plants coming on-line in 1995 are estimated to cost between 38 and 46 mills per kilowatthour. These estimates are shown on Exhibit C.

Capital costs account for a little less than half of these costs, 16 to 20 mills per kilowatthour. Fuel costs account for 11 to 15 mills per kilowatthour. O&M and other costs account for 11 mills per kilowatthour.

Q. **How did you calculate the mills per kilowatthour capital cost estimate?**

A. First, I converted my total capital cost estimate (which includes allowance for funds used during construction to pay for interest) expressed in dollars per kilowatt of capacity to a real (i.e., inflation adjusted) levelized annual cost estimate in dollars per kilowatt per year. This levelized annual capital cost has the same present value as the actual year-by-year capital charges. I did this by multiplying the dollar per kilowatt cost by a capital charge rate of 0.094.

The capital charge rate assumes that capital costs are recovered over a thirty year period. The rate also assumes that the utility cost of capital is 5.6 percent in real terms.

Second, I converted the annual per kilowatt cost to a per kilowatthour cost using a capacity factor of 75 percent.

Q. **How did you calculate the mills per kilowatthour fuel cost estimates?**

A. First, I calculated a real, levelized annuity price in $/MMBtu which has the same present value as the actual year-by-year fuel costs. I used a discount rate of 5.6 percent, and calculated the cost over a thirty year period.

Second, I multiplied the real levelized fuel cost by the powerplant heat rate in Btu per kilowatthour. I assumed 7200 Btu/KWh and 8800 Btu/KWh for new gas and coal powerplants, respectively.

Q. **How did you calculate the mills per kilowatthour O&M cost estimate?**

A. First, I used available O&M real levelized annuity cost estimates. These estimates divided the costs into fixed annual O&M costs expressed in units of real dollars per year, and variable O&M cost estimates expressed in mills per kilowatthour.

Second, I converted the fixed annual O&M costs to per kilowatthour costs using a 75 percent capacity factor.

Finally, I added the variable and fixed O&M costs.

Q. **How does the total mills per kilowatthour compare to the total present value of powerplants costs?**

A. The total present value of the costs of a 300 megawatt coal powerplant over thirty years that costs 46 mills per kilowatthour on a levelized real annuity basis is $2.72 billion. This cost is calculated by multiplying the number of kilowatthours generated during the thirty year period by the 46 mills. The cost of a similar sized coal plant costing 38 mills per kilowatthour is $2.25 billion.

Cost components estimated in real levelized annuity mills per kilowatthour can also be calculated by multiplying total plant production by the mills per kilowatthour cost.

Q. **What uncertainties affect this cost estimate?**

A. One important uncertainty with respect to coal powerplant costs is the initial capital investment cost. Capital costs account for little less than half of the total coal powerplant cost. Further, capital costs are uncertain. The estimates developed by organizations like EPRI of capital costs for coal powerplants are based in part on historical average experience. Coal powerplant costs have varied, and in some cases have been significantly lower than average. Coal powerplant cost variability occurs because they vary in design, size, labor costs, and contracting arrangements.

Q. What are the differences between the high and low total coal powerplant cost estimates?

A. The lower cost estimate is based on a capital investment cost estimate of $1100 per kilowatt taken from a recent bid from a coal powerplant developer in Florida. The higher coal powerplant cost estimate of $1425 per kilowatt uses a generic capital cost estimate developed by the Electric Power Research Institute.

The high estimate of total coal powerplant cost uses an ICF Resources forecast of delivered coal prices to Florida of $1.65 per MMBtu. The low estimate uses delivered coal costs taken from recent spot coal shipments to Florida.

There is no difference in O&M costs between the low and high estimates. Both estimates of total coal powerplant cost use EPRI generic estimates for other factors such as powerplant efficiency (39 percent) and O&M costs.

Q. **How does your coal price forecast compare to current delivered coal prices in Florida?**

A. ICF Resources' forecast is ten to fifteen percent lower than the costs of most of the coal delivered to Florida under long-term contract. It is 27 percent higher than the spot price of coal used in the low case.

Q. **How does ICF Resources coal price forecast compare to the coal price forecast of Florida Electric Power Coordinating Group (FEPCG)?**

A. The coal price (greater than 2.5 percent sulfur coal) forecast of FEPCG is $1.77 per MMBtu on a levelized annuity basis. This is slightly higher than the ICF Resources forecast. If the FEPCG forecast is correct, then gas will be slightly more competitive than shown here.

Q. **What is your estimate of the cost of new baseload natural gas powerplants?**

A. New natural gas baseload plants cost between 36 and 43 mills per kilowatthour. Fuel costs account for a little more than one-half of the total costs, 23 to 27 mills per kilowatthour. Capital costs are less, about one-quarter of the total, 9 to 11 mills per kilowatthour. Capital costs are a smaller portion of the gas powerplants relative to coal powerplants because gas plants cost less to build. The remaining costs are O&M costs, 4 mills per kilowatthour.

Q. **What is the most significant uncertainty in the case of new natural gas plants?**

A. The biggest uncertainty is gas prices. Historically, gas prices have been more volatile than coal prices. This uncertainty is reflected in the wide range of gas forecasts. For example, the low estimate of total natural gas powerplant costs uses ICF Resources' base case forecast of future natural gas prices delivered to Florida utilities on a levelized real annuity basis of $3.25 per million British thermal units (MMBtu). The higher total cost estimate uses a higher natural gas levelized real annuity price forecast of $3.75 per MMBtu delivered to Florida utilities, developed using the U.S. Department of Energy's Energy Information Administration's *1993 Annual Energy*

Outlook wellhead gas price, to which I added estimated transportation costs.

The second uncertainty affecting the range of estimates is future natural gas powerplant capital costs. The lower total cost estimate also uses a generic capital cost estimate developed by EPRI of $600 per kilowatt. This is very similar to Florida Power's capital cost estimate in its September 16, 1991 Direct Testimony and Exhibits Volume II Study, Docket 910759-EI. The higher total cost estimate uses a capital cost estimate of $800 per kilowatt from a recent bid for a new natural gas powerplant. Both estimates use EPRI generic estimates for other factors such as powerplant efficiency (47 percent), and O&M costs.

Q. **How does the ICF Resources forecast of natural gas prices compare to other selected forecasts and indicators of future prices?**

A. ICF Resources' forecast of natural gas prices is lower than other forecasts. For example, ICF Resources' forecast of average U.S. well head prices in 2010 in 1991 dollars is $2.80/Mcf versus $3.68/Mcf in the EIA reference case forecast of January 1993, and $4.82/Mcf in the EIA reference case forecast of 1992 (see Exhibit D).

Q. What is the 1992 FEPCG forecast of delivered natural gas prices in Florida?

A. The FEPCG forecast of delivered real (1991 dollars) natural gas prices on a levelized annuity price basis is \$3.80/MMBtu which is \$0.05 or 1 percent higher than the EIA forecast.

Q. Have gas companies been willing to sign long-term contracts for gas at prices consistent with the low end of this range?

A. Yes. While this does not mean the gas companies are right, it does provide evidence that some gas companies believe that gas prices will remain low over the long-term.

Q. What do you conclude from a comparison of new baseload coal and natural gas powerplant costs for plants coming on-line in 1995?

A. The range of costs for new coal and natural gas powerplants overlaps. However, the bottom end of the gas range is lower than the low end of the coal range, though not enough to indicate that on the basis of costs all of one type or another will be built. Rather, a mixture of both appears likely.

Q. Does this cost comparison have different results for powerplants coming on-line in 2000 or 2010 rather than 1995?

A. The cost estimates stated above were developed for a powerplant beginning operation in 1995. The competition between coal and gas powerplants in later years also appears not to be clear cut.

On the one hand, coal might become more competitive since gas prices are forecast to increase over time while coal prices are not.

On the other hand, concern about global climate change and about emissions of greenhouse gases such as carbon dioxide (CO_2) might lead to new regulations adversely affecting coal's competitive position *vis-a-vis* gas. Although it is difficult to analyze the magnitude of this potential, a CO_2 tax could greatly disadvantage coal as an option on an expectations basis. In many of the cases ICF Resources analyzed for EPRI in a recent study of climate change impacts on electric utilities, utilities were taxed at a rate of $50 dollar per ton. A $50 per ton CO_2 tax could increase coal's costs by an extra 23 mills/kwh relative to gas. Coal's cost increase more than gas's cost primarily because coal is a more carbon intensive fuel.

Furthermore, while new technology could change the costs of both coal and gas, we think that these developments might favor gas. Gas turbine technology has been improving significantly in past years.

Also, new technologies are being developed to "repower" existing oil and gas powerplants. Repowering usually involves using new advanced technology at a plant site that would otherwise retire. While there are not many oil plants in Florida scheduled to retire before 2010, there are some. The repowered plant could cost less than building a gas plant at a new site using new technologies. Repowering also allows the utility to use an existing site. This is a real advantage since new powerplant sites are difficult to obtain. Many of these old, existing, oil powerplant sites in Florida would not be acceptable locations for coal use. While repowering could occur at coal plant sites, most of the coal powerplants in Florida are likely to be ready for retirement much later than the older existing oil and gas plants.

Q. **What other, non-cost factors affect fuel choice decisions?**

A. There are four leading risks that affect the decision on fuel choice and powerplant technology type: (1) fuel price risk, (2) demand risk, (3) capital risk, and (4) environmental regulatory risk. Overall, these factors may confer a slight, but not decisive, advantage to natural gas.

Q. **What is fuel cost risk, and does it favor coal or gas?**

A. Fuel cost risk refers to the degree to which fuel costs will differ from expectations, especially the potential that costs will be higher than expectations. The potential that natural gas prices will be significantly higher than forecast is greater than the potential that coal prices will be significantly higher. Natural gas prices have historically been more volatile, and there is much less natural gas than coal in the U.S. Also, there is more disagreement among available forecasts of prices (see Exhibit D).

Natural gas prices might also be less than expected. Thus, measures taken to protect against high natural gas prices might result in higher consumer costs.

In the event of higher natural gas prices, however, electric utilities could retrofit gas plants with new coal gasification technology. This new technology is actively being demonstrated by the U.S. Department of Energy's Clean Coal program.

This would reduce the effect of natural gas price uncertainty.

Q. What is demand risk and does it favor coal or gas?

A. Demand risk refers to the potential that demand when a new powerplant is completed is less than was expected when the decision was made to build it several years earlier. For example, in the 1970s and 1980s, many utilities added powerplants, but ended up with excess capacity because demand grew more slowly than expected.

Gas powerplants are generally smaller than coal powerplants, and can be built with less lead time (three to four years versus four to seven years). They can also be added in phases since gas powerplants have distinct modular components. For example, a gas turbine can be added first, followed later by a heat recovery boiler and a steam turbine. Thus, gas additions can be more closely tailored to demand growth, and hence they entail less risk that too much capacity will be added because demand growth fails to meet expectations.

Q. What is capital risk, and does it favor coal or gas?

A. Capital risk is related to demand risk and refers to the potential that the costs of underutilized powerplants will be paid by consumers. Larger, higher fixed cost powerplants have higher financial risk. The fixed costs of natural gas powerplants are usually less than that of coal powerplants. Costs of construction of coal-fired plants are also harder to predict and control. Thus, there is less financial risk associated with gas powerplants even for coal and gas units at the same site. The one exception is low utilization gas powerplants. At these plants, the fixed costs of firm pipeline capacity are large as a portion of average kilowatthour costs.

Q. **What is environmental regulatory risk, and does it favor coal or gas?**

A. Both the coal and natural gas options discussed comply with all current environmental regulations. However, laws and regulations may be promulgated in the future. We expect that, if there are changes, they will make the existing regulations more stringent.

Environmental regulatory risk refers to the potential that future regulations will become more stringent, and result in retrofit control costs. There is less risk that future environmental regulations will adversely affect natural gas powerplants than coal powerplants. This is because natural gas powerplants have: (1) no solid waste products compared to coal powerplants which generate coal ash and often flue gas desulfurization wastes, (2) less CO_2 emissions, as mentioned earlier, (3) practically no SO_2 emissions, and (4) less nitrogen oxide emissions.

In particular, new coal powerplants result in:

- 127 percent higher emissions of CO_2, a greenhouse gas and a potential cause of global climate change, than gas powerplants.
- More solid waste; gas powerplants produce no solid waste.
- 633 percent more nitrogen oxide emissions.
- More SO_2 emissions on a local area basis that may be subject to increased local oversight.

Q. **Do the risk considerations change your view that a mixture of coal and gas will be used to meet baseload demand growth?**

A. In light of these considerations, natural gas appears to have an advantage over coal in the areas of risk. However, this advantage is not decisive enough to eliminate coal as an option, especially not from a conservative estimate of the share of gas.

Because of these risk factors, consumers may be better served by a policy of diversification. The degree to which risk affects decisions is very difficult to assess quantitatively and depends on both consumer attitudes towards risk and the uncertainty in prices.

Q. **What is your conservative estimate of the share of gas in new baseload powerplants?**

A. I conservatively estimate that new baseload power-plants in Florida during the period through 2010 will be split evenly between coal and natural gas. I believe this to be the minimum share that will go to gas, based upon the above considerations.

Section II.4 - Intermediate Load

Q. **What are the principal options for new intermediate load powerplants?**

A. Coal and natural gas are also the principal options in this load segment.

Q. **What are the costs of new coal and natural gas powerplants in intermediate load?**

A. Powerplant cost estimates barely overlap; gas costs appear are almost universally lower. Coal powerplants cost between 46 and 55 mills per kilowatthour versus 40 to 48 for natural gas powerplants.

Q. **Why are these estimates higher than for baseload powerplant cost estimates?**

A. These costs are higher on a per kilowatthour basis than the baseload cost estimates because fixed capital charges and O&M costs are spread over fewer hours. Thus, costs are higher on a per unit of electricity produced basis.

Q. **Why is the competitive position of coal and natural gas powerplants different in this market segment?**

A. In this market, powerplants are utilized less than in the baseload segment. As a result, the competitive advantage of gas relative to coal is significantly clearer in the intermediate load segment. Coal powerplant costs increase more because they have more fixed costs (e.g. capital, and fixed O&M costs) than gas powerplants, and these costs are spread over less hours.

Q. **Are there non-cost advantages to natural gas use for this segment?**

A. Powerplants operating in intermediate load, and even more so in the seasonal and daily peaking load segments, frequently change their load levels to meet changes in demand. Natural gas powerplants are able to rapidly adjust their output to changes in customer electricity demand, while coal-fired powerplants cannot.

Q. **What are the implications of cost and non-cost factors on fuel choice in this fuel market?**

A. In light of the competitive advantage of gas in this segment, I estimate gas's share of this market to be larger than in the baseload market segment. On a conservative basis, I estimate that 75 percent of the new intermediate capacity built in the state will use gas, and the remainder will use coal. In comparison, for baseload powerplants I estimate a 50 percent share for gas.

Section II. 5 - Seasonal Peaking Powerplants

Q. **What are the principal fuel choice options in the seasonal peaking market?**

A. The principal options are natural gas and distillate oil powerplants.

Q. **Why are coal powerplants not likely to be attractive options in this market?**

A. In this market, powerplants are used much less than in the baseload and intermediate segments, approximately 10 to 40 percent per year. Coal powerplants are not likely to compete successfully in this market mainly because the large fixed costs of coal powerplants are spread over so few hours that they are not competitive. In comparison, gas powerplants have lower fixed costs.

Q. **Why are renewables such as wind and solar not competitive in this market?**

Our studies indicate that under favorable conditions, renewable powerplants can play important niche roles in meeting peak demands for electricity with current technology. However, their role is likely to be limited in Florida, particularly because: (1) based on our review of the literature, Florida and surrounding areas have relatively poor wind resources relative to other parts of the U.S. (attaining even 10 percent average capacity factors in Florida may not be possible), (2) solar power capital costs, as estimated by EPRI, are very high, and (3) these sources are intermittent, they provide less contribution towards meeting peak demand, and they have not been integrated on a large scale in utility generation systems.

Natural gas combined cycles provide very strong competition to these plants. Exhibit F shows the levelized average costs for these options.

Q. **Why are distillate oil powerplants competitive with natural gas options in this load segment?**

A. Oil powerplants start to become competitive, at lower utilization levels even though oil and natural gas powerplants are very similar in terms of capital investment costs and other non-fuel parameters. For the purposes of this analysis of the need for new gas pipeline capacity in Florida, I am defining a natural gas powerplant as one that reserves firm capacity on a pipeline so that it may always burn gas. It is possible that a "distillate oil" powerplant may be able to burn gas economically on an interruptible basis, but this plant would not directly affect the need for firm pipeline capacity in Florida.

Oil is competitive even though ICF Resources forecasts indicate that distillate will become significantly more costly over time than natural gas. Oil's competitiveness derives from the fact that it can be delivered without the construction of new pipeline capacity. In contrast, natural gas costs increase as the utilization of the firm pipeline capacity decreases and the fixed charges associated with the pipeline are spread over fewer units.

Q. **How big is the impact of pipeline utilization on delivered natural gas costs?**

Using ICF Resources' forecasts of wellhead prices, total delivered costs for a firm capacity holder assuming pipeline utilization of 90 percent is $3.25 per MMBtu on a real levelized annuity price basis. At 25 percent utilization, delivered gas costs are $4.89 per MMBtu, fifty percent higher.

Q. **What did you assume for pipeline utilization given your forecast of the utilization level of new gas powerplants?**

A. I assumed pipeline utilization equal to the powerplant capacity factor plus 15 percent up to a maximum of 90 percent. For example, the gas transportation costs of a powerplant operating at 50 percent utilization level were calculated assuming pipeline utilization of 65 percent. This enabled me to conservatively estimate the costs of reserving pipeline capacity facing a utility considering such an option. Higher pipeline utilization would make reserving pipeline capacity for a given powerplant more attractive.

Q. **At what capacity factor will oil and gas peaking powerplants be equally competitive?**

A. Even though oil is more competitive in this market than in intermediate and baseload, it still costs more than gas at capacity factors greater than 3 percent when using ICF Resources' natural gas prices (see Exhibit F), and 7 percent when using EIA natural gas prices (not shown). In other words, it is more economic for a utility to reserve pipeline capacity for a powerplant operating over 3 to 7 percent of the time than to burn only oil in that plant.

Q. Does the oil cost estimate shown include the added cost of oil taxes proposed by President Clinton?

A. No. If, as proposed by President Clinton, oil taxes are about $0.25 per MMBtu higher than gas taxes, then oil would be even less competitive than shown here. This would mean that gas will be competitive with oil at lower capacity factors.

Q. What is your conservative estimate of fuel choice and pipeline requirements for seasonal peaking plants?

A. A large portion of the new seasonal peaking load will consume natural gas. However, only some of these will be willing to purchase firm gas pipeline supply. Thus, a conservative estimate of 50 percent is used for gas market share in this market segment.

Section II.6 -Daily Peaking

Q. What are the principal options in this segment?

A. The principal options are oil and natural gas. Coal is even less competitive in this segment than in seasonal peaking since fixed costs are spread over even fewer hours. Renewables have the problems mentioned above.

Q. What technologies would be used in this segment?

A. Combustion turbines, a low cost powerplant, and a component of the combined cycles used in other segments would be preferred for either distillate oil or gas. Combustion turbines have higher fuel costs than combined cycles because they are less efficient, but they have less capital investment costs.

Q. Will natural gas be used by new daily peaking powerplants?

A. Yes, when interruptible supply is available, costs less than distillate, and can be burned in a given unit. ICF Resources forecasts that interruptible gas will cost less than distillate oil.

Q. **What is a conservative estimate of the share of new peaking powerplants willing to purchase firm pipeline capacity?**

A. In this segment, powerplants are only used for a fraction of the year during the peak periods of electricity demand which generally occur during winter. Firm gas supply is not competitive in this sector since the costs of natural gas pipeline capacity must be spread over a few hours of powerplant operation. My conservative estimate is that none of these new daily peaking powerplants will reserve additional pipeline capacity.

Q. **Please summarize your conservative estimates of the share of new powerplant capacity demanding new pipeline capacity.**

A. In this section, I have testified that natural gas powerplants that use firm pipeline capacity can be expected to be the choice at: (1) 50 percent of baseload powerplants, (2) 75 percent of intermediate load powerplants, (3) fifty percent of seasonal peaking plants, and (4) zero percent of daily peaking powerplants (see Exhibit H).

Q. **Please summarize why you think these estimates are conservative with respect to pipeline capacity requirements.**

A. In each segment we have been careful to be conservative in the estimated share we give to gas. We believe these numbers are conservative because utility plans are heavily weighted towards gas; ICF's forecasts are more favorable to gas than some of the government forecasts as a result of on-going research; and most of the non-quantifiable risks, such as environmental and financial risks, also favor gas.

Q. Please summarize your analysis of fuel choice.

A. Utilities plan to choose gas as the principal fuel for two thirds of their powerplants. Our conservative assessment of the economics indicates that except for daily peaking, 50 to 75 percent of the plants will need new gas pipeline capacity. Thus, I conclude the fuel choice for new powerplants will lead to substantial increased gas pipeline demand.

SECTION III - FUEL CHOICE AT EXISTING OIL POWERPLANTS

Q. Why are you analyzing fuel choice at existing plants?

A. Many utilities that have powerplants now using oil would like to use gas in them because it costs less. Some of these plants may be willing to use more gas if new pipeline capacity were available.

Q. **How much existing powerplant capacity could use natural gas in Florida but is not doing so?**

A. Florida currently has 20 gigawatts of existing generation capacity which uses natural gas, oil or both. One-third of the fuel consumed at these plants is gas and two-thirds is oil. In general, all these powerplants can currently use gas, or their on-site equipment could be converted to the use of natural gas. For example, in 1991, about 6 gigawatts of Florida Power & Light's steam powerplants consumed both oil and gas; the utility's other 3 gigawatts of steam plants burned oil only. If more gas were available at current prices, they could use more because it costs less than oil. Since 1985, the year most gas became deregulated, gas in Florida has been less costly every year than one percent sulfur residual fuel oil, the type of oil than can be used at most plants in Florida. Hence, some utilities may be willing to purchase firm pipeline capacity to ensure the availability of gas.

Q. **How is the decision to switch to gas from oil different from the decision between new oil and gas powerplants?**

A. The decision to obtain more pipeline capacity for increased use of natural gas is different than the decision about fuel choice involved in the construction of new powerplants. This is because very little new capital investment is required in order to switch existing powerplants to gas.
The decision is also different because natural gas is often competing against a different type of oil. Residual fuel oil, the fuel used at existing powerplants, contains much more sulfur and costs less than distillate oil, the fuel that would be used at new oil powerplants. Distillate is used at new powerplants in order to take advantage of combined cycle and combustion turbine technology which requires clean fuels.

Q. **Are there regulations with important consequences for the decision to switch that are less important in the new powerplant market?**

A. Yes. By 2000, sulfur dioxide emissions of all Florida utilities will be regulated under the acid rain provisions of the Clean Air Act Amendments of 1990. Under these new regulations, utilities will receive a fixed level of sulfur dioxide (SO_2) emission allowances each year. The utility can emit SO_2 at this level, exceed this level if it can purchase allowances from other utilities, or sell extra allowances if the utility over-controls. Thus, Florida utilities and consumers can save money to the extent utilities control SO_2 emissions at a cost less than the market value of allowances. Since gas contains practically no SO_2, switching to gas could increase the amount of allowances that can be sold. Conversely, not using gas could impose additional costs on utility customers. SO_2 allowance costs were also added to the costs of new coal powerplants, but they are smaller than in the case of existing oil/gas plants because new coal powerplants were assumed to use SO_2 scrubbers and have very low SO_2 emissions.

Q. **Is the decision to switch to gas and obtain incremental gas pipeline capacity affected by plant utilization levels?**

A. Yes. The decision between continued use of oil and gas differs between powerplants with different utilization levels. If a powerplant purchases pipeline capacity, delivered natural gas prices are high at low utilization plants, since pipeline reservation charges are spread over small amounts of natural gas. In contrast, delivered oil prices are much less affected by plant utilization levels.

Q. **Will there be baseload oil plants which could switch to gas?**

A. No. Oil and gas powerplants cost more to operate on a variable cost basis than coal and nuclear units. Once a plant is built, the decision to operate it is made based on variable costs alone. Thus, almost no existing oil or gas plant currently operates in baseload utilization levels and almost none are expected to operate at utilization levels high enough to qualify as baseload in 2000 or later, and hence no baseload oil or gas plants will be available to add to demand for pipeline capacity.

Q. **How did you estimate the amount of demand for power in baseload and other load segments, and the extent to which existing oil plants will be used to meet this demand?**

A. ICF Resources analyzed the hourly demand for electricity and estimated the amount of demand in baseload and in other segments. The shares of capacity in each load segment are 33, 29, 22 and 16 percent for baseload, intermediate, seasonal peaking, and daily peaking, respectively.

ICF Resources also conducted an assessment of which type of powerplants will be used in each demand segment. This integration of demand and supply was undertaken using ICF Resources' Coal and Electric Utilities Model (CEUM) is a linear programming regional and state-specific model of the U.S. electric utility and coal industries. The model integrates an assessment of electricity demand, and demands for powerplant fuel, with supply from coal, and other fuel industries, and with generation supply options. This model has been widely used by the U.S. Department of Energy, the U.S. Environmental Protection Agency, and dozens of private electric utility and industry clients.

Q. **Will daily peaking existing oil powerplants use natural gas?**

A. Yes. These plants will use gas supplied on an interruptible basis when available.

Q. **Will these plants demand additional gas pipeline capacity?**

A. No. Firm gas supplies cannot compete with oil at daily peaking powerplants where the utilization of the pipeline would be so low.

Q. **Please outline the remainder of this section.**

A. The remainder of this section focuses on the potential that intermediate and seasonal peaking oil powerplants will shift to gas and demand firm pipeline supply.

Q. **What are the costs of gas and oil at existing intermediate load powerplants?**

A. The most important factor affecting the choice of natural gas versus oil are the respective prices of the two fuels.

The cost of firm gas supply delivered in intermediate load in 2000 on a levelized basis is forecast to range between $4.00 and $4.50 per MMBtu. The lower cost estimate is based on ICF Resources' forecast of natural gas, and the higher cost estimate is based on the EIA forecast (see Exhibit I).

In contrast, the cost of 1 percent sulfur residual oil, the type of oil that can be used at most of Florida's powerplants, including the cost of SO_2 emission allowances (approximately $0.10 to $0.25 per MMBtu), is projected to be $4.98 to $5.13 per MMBtu in 2000 on a real levelized annuity basis.

Q. **What is the source of the oil price forecast?**

A. The oil cost estimate is based on ICF Resources' forecast of residual oil prices. We expect one percent residual fuel oil prices to increase 65 percent in real terms between 1992 and 2000 for two reasons. First, world crude oil prices will increase 25 percent in real, inflation-adjusted terms between 1992 and 2000. Second, we expect that oil refineries will increase their capacity for converting residual oil to other oil products, thus eliminating the current excess supply of residual oil.

Q. Does the oil cost estimates shown include the added cost of energy taxes proposed by President Clinton?

A. No. However, as proposed by President Clinton, oil taxes are about $0.25 per MMBtu higher than gas taxes, then oil would be even less competitive than shown here.

Q. How does your forecast of residual oil prices compare to other forecasts?

A. The Florida Electric Power Coordinating Group forecasts that less than one percent residual oil prices will increase 53 percent in real terms between 1992 and 2000.

Q. What is the assumed range of SO_2 allowance prices?

A. $200 to $500 per ton on a levelized real annuity basis.

Q. What is the source of the SO_2 allowance price estimates?

A. The range of allowance price estimates was taken from public literature.

Q. What are the implications of the costs of oil and gas at intermediate powerplants?

A. The range of gas costs is lower than the range of oil costs. I believe a conservative assessment would indicate that 75 percent of the capacity is assumed to use natural gas supplied on a firm basis.

Q. What are the costs of gas and oil at existing seasonal peaking load powerplants?

A. The cost of natural gas in seasonal peaking load in 2000 on a levelized basis ranges between $4.53 and $5.05 per MMBtu. This gas cost range is higher than the intermediate load cost since pipeline costs are spread over fewer Btus. Again, the lower cost estimate is based on ICF Resources' forecast of natural gas, and the higher costs is based on the EIA forecast.

In contrast, the cost of 1 percent residual oil is unchanged relative to intermediate load, $4.98 to $5.13 per MMBtu. The oil cost estimate is unchanged because the fixed costs of oil use are very small (e.g., no specialized pipelines are required).

Q. **What are the implications of these cost estimates, and are there other factors affecting fuel choice decisions at existing oil plants?**

A. Since the low end of the range of gas costs is lower than the low end of the range of oil costs, and the range of gas costs only somewhat overlaps the range of oil costs, gas appears to have a competitive edge. Further, there are some additional advantages associated with natural gas use. First, oil prices have been even more volatile than natural gas prices, and OPEC market power can affect oil prices while no such market power exists in the United States. Natural gas use results in an approximately 30 percent decrease in carbon dioxide emissions relative to residual fuel oil. As mentioned, it is possible that these emissions may be regulated in the future. Natural gas use may also reduce NO_x and sulfur dioxide emissions relative to oil use. Finally, as noted previously, oil taxes may be increase more than gas taxes, and the above estimates do not reflect this possibility.

On the other hand, the competitive position of gas is less for capacity factors less than 25 percent.

Thus, conservatively, I assume that only 50 percent of the capacity is assumed to use natural gas.

Q. **In summary, to what degree will natural gas displace oil consumption at existing Florida powerplants, and how much existing powerplant capacity will seek firm pipeline capacity supply?**

A. Powerplants in all load segments will seek to purchase gas when available. Also, a significant share of existing oil capacity will be likely to demand firm pipeline supply. Specifically, I estimate that 75 percent of the capacity used in intermediate load, 50 percent of the seasonal peaking capacity, and zero percent of the daily peaking capacity will require firm pipeline capacity.

SECTION IV - ESTIMATES OF FUTURE DEMAND FOR NATURAL GAS PIPELINE CAPACITY

Q. **What is your estimate of the demand for pipeline capacity in 2000?**

A. Pipeline capacity requirements from the electric utility sector plus non-electric demand at 1992 levels will be 3.8 Bcf/day (see Exhibit G). This assumes that electricity demand growth will be equal to the level forecast in the 1992 Ten Year Plan, 2.6 percent per year, and that the share of capacity opting for pipeline capacity will be equal to my conservative estimates.

Q. **How does your estimate compare to available pipeline capacity including the proposed SunShine pipeline?**

A. Pipeline capacity, assuming final approval and construction of Florida Gas Transmission Phase III, is about 1.5 Bcf/day. Thus, pipeline demand is larger than pipeline supply by 2.3 Bcf/day. If the SunShine pipeline were built with a capacity of 0.8 Bcf/day, demand would still exceed supply.

Q. **Does this forecast assume any increase in demand for pipeline capacity outside the electric sector?**

A. No. My forecast considers only the growth in pipeline capacity requirements of the electric utility sector. Demand growth for gas in other sectors would increase the need for additional pipeline capacity above the estimates shown here.

Q. **What is your estimate of the demand for pipeline capacity in 2010?**

A. Pipeline capacity requirements from the electric utility sector plus non-electric demand at 1992 levels will be 5.0 Bcf/day. This estimate assumes that electricity demand growth will be equal to the level forecast in the 1992 Ten Year Plan, 2.6

percent per year, and that the share of capacity opting for pipeline capacity will be equal to my conservative estimate.

Q. **How does your estimate compare to available pipeline capacity including the proposed SunShine pipeline?**

A. Pipeline capacity, assuming Florida Gas Transmission Phase III receives final approval and is brought on line, is 1.5 Bcf/day. Thus, demand will exceed supply by 3.5 Bcf/day. The SunShine pipeline has a capacity of 0.3 Bcf/day, and thus demand would still exceed supply even if the line were built.

Q. **Is it possible that demand from the electric sector will be greater than shown?**

A. Yes. If demand for electricity grows at the rate of the high sensitivity case, 3.8 percent per year, pipeline capacity requirements from the electric utility sector plus non-electric demand at 1992 levels will be 4.2 Bcf/day in 2000 and 6.0 Bcf/day in 2010.

In this case, demand will exceed available pipeline capacity by 2.7 to 4.5 Bcf/day.

Demand could be even higher if less conservative assumptions are used about the share of capacity demanding firm gas supply, the retirement of Turkey Point nuclear powerplant units 3 and 4, and the if non-electric demand for pipeline capacity grows.

Q. **What are the risks that pipeline demand will not be enough for the full SunShine project?**

A. Assuming (1) that electricity demand growth is as low as in the lowest electricity demand sensitivity case (e.g., 1.7 percent per year), (2) that a conservatively estimated share of capacity chooses firm gas supply, and that (3) there is zero growth in non-electric demand for gas, 3.5 Bcf/day of pipeline capacity will be needed in 2000, and 4.2 Bcf/day in 2010. Demand would be greater than available supply by 2.0 Bcf/day in 2000, and by 2.7 Bcf/day in 2010. Thus, even in the scenario with the lowest demand for pipeline capacity if the SunShine pipeline with a capacity of 0.8 Bcf/day were added, demand would still be greater than supply.

Q. **What were the steps involved in developing these estimates?**

A. In each year and for each scenario, the total amount of powerplant capacity in the load category was estimated - i.e. baseload, intermediate, seasonal peaking and daily peaking.

This amount of capacity was further divided into powerplant capacity that could be gas-fired and that which could not. For example, existing nuclear and coal powerplants were assumed not to be capable of using natural gas, while all existing oil or gas powerplants, and all new powerplants were assumed to be potentially gas capable.

These estimates, as mentioned earlier, were developed using ICF Resources' Coal and Electric Utilities Model (CEUM).

The analysis in Section II determined the portion of these plants assumed to use firm gas supplies. The natural gas powerplants were then divided into two groups. The first are combined cycles with an average heat rate of 7,200 Btu/Kwh with an daily peak demand of 0.17 Bcf/day per gigawatt. The second group are combustion turbines and existing oil/gas capacity with a heat rate of 11,000 Btu/Kwh and a daily peak demand of 0.26 Bcf/day per gigawatt. The detailed calculations are attached (see Exhibit J). The non-electric demand for gas was assumed to be 0.4 Bcf/day in all years and for all scenarios. Total gas pipeline demand was the sum of electric and non-electric sector demand.

Q. **What are the sources of your heat rate estimates?**

A. The 7,200 Btu/Kwh is based on expected downward revisions to EPRI's Technical Assessment Guide (TAG); current EPRI estimates are higher and would result in even greater gas pipeline requirements. This heat rate is for high utilization. Combined cycles utilized at low levels may have higher heat rates.

The estimated heat rate of 11,000 Btu/Kwh is based on two sources. EPRI's TAG currently estimates new gas combustion turbine heat rates at 11,500 Btu/kwh. Existing oil and gas stream plants in Florida typically have heat rates in the 10,500 to 11,500 range. Often, as power plants age, heat rates increase. I chose 11,000 Btu/Kwh for all years as a conservative estimate.

Section V - Summary of Findings

Q. Please summarize your principal findings.

A. The growth in electric generation demand in Florida will justify more pipeline capacity for new powerplants. In addition, existing powerplants burning oil will demand firm gas supplies requiring more pipeline capacity.

The extent of the demand for new powerplants depends on (1) the growth rate in electricity demand, (2) whether the new plants will choose gas as their primary fuel, and (3) whether they want firm pipeline capacity. My investigation of forecasts by the Florida Electric Power Coordinating Group's (FEPCG) Ten Year Plan and of those announced by utilities, supplemented by a review of historical electricity demand growth and sensitivity projections that I developed, indicates that even if future conditions tend to minimize demand growth, significant electricity demand growth is still likely to occur by 2000 and even more by 2010.

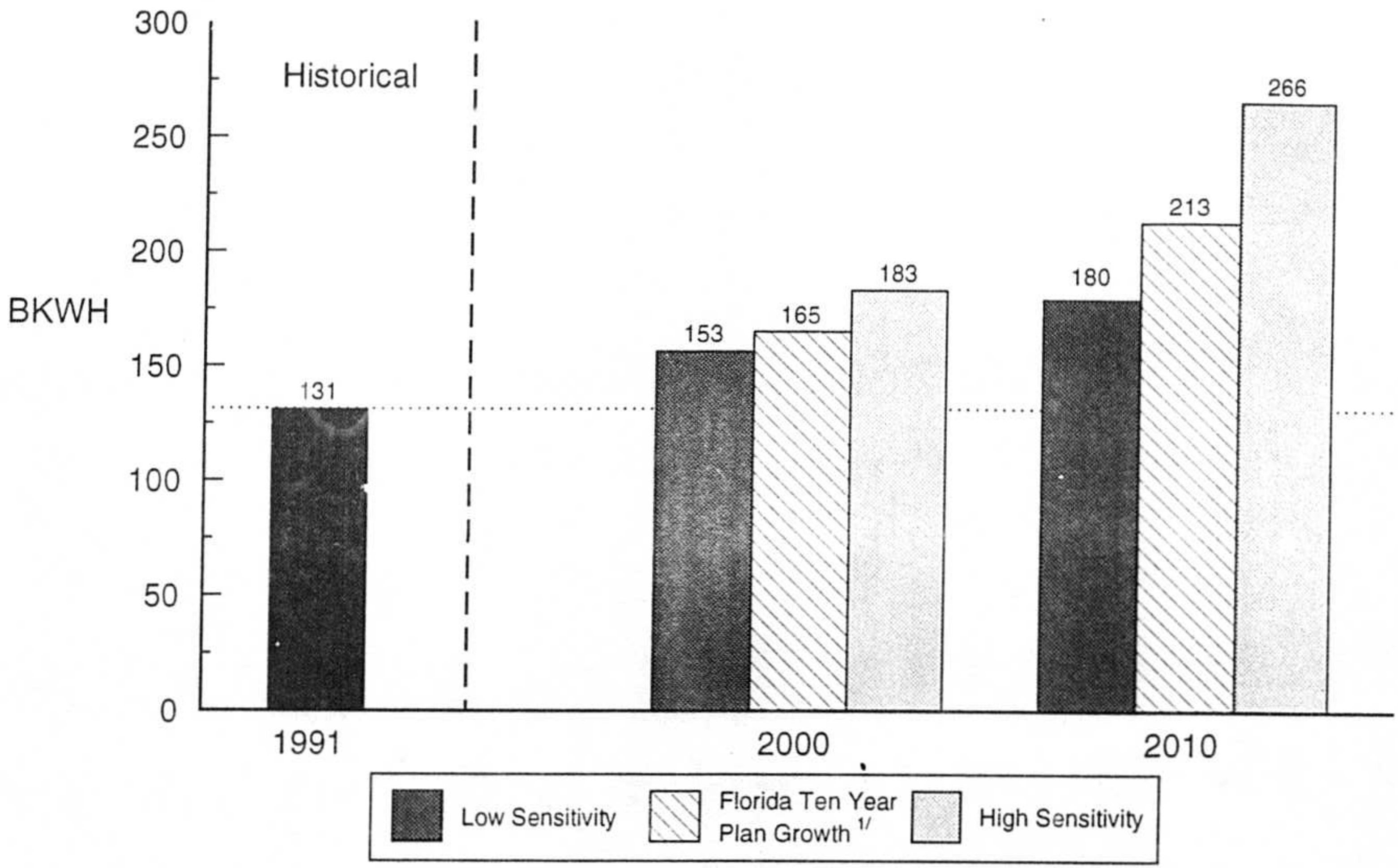
Florida utilities expect that most (about 67 percent) of their new powerplants will be gas-fired. My analysis of the economics of new powerplant options indicates that even using conservative assumptions about fuel choice, a large share of new powerplants will be gas-fired and need new pipeline capacity.

The extent to which existing oil/gas plants in Florida will prefer gas and seek firm gas supply depends primarily on gas and residual oil prices. The decision will also be influenced by acid rain regulations, which favor gas use over oil, and potential new federal energy taxes, which also favor gas use over oil use. My analysis of the economics indicates a large portion of existing plants will use gas and seek firm pipeline capacity.

I estimated demand for gas pipelines in Florida using alternative electricity demand growth scenarios. Using the FEPCG's Ten Year Plan as the basis for electricity growth rates results in total demand for pipeline capacity in 2010 of 5.0 Bcf/day. This result is 3.5 Bcf/day greater than the 1.5 Bcf/day of capacity that will be available if Phase III additions to Florida Gas Transmission are approved. In 2000, total demand will be 3.8 Bcf/day, or 2.3 Bcf/day above available supply. Thus, even in 2000, the demand for pipeline capacity will be much larger than the available capacity even if the proposed SunShine pipeline is built. All my estimates make the following conservative assumptions: (1) no growth in non-electric demand for gas; (2) conservative estimates of the share of plants choosing firm gas supply; and (3) no retirement of existing nuclear power plants until after 2010.

Even when I used assumptions that result in low electricity demand growth and low demand for pipeline capacity, demand for pipeline capacity exceeds supply by 2.0 Bcf/day in 2000 and 2.7 Bcf/day in 2010. Thus, even if the SunShine pipeline is added, demand will exceed supply.

FLORIDA GENERATION REQUIREMENTS IN 2000 AND 2010



1/ Average electricity demand growth for 1992-2001 extended to 2010; conservatively assumes that imports of power grow at same rate as demand. If imports fail to keep up with demand, more generation than shown is required.

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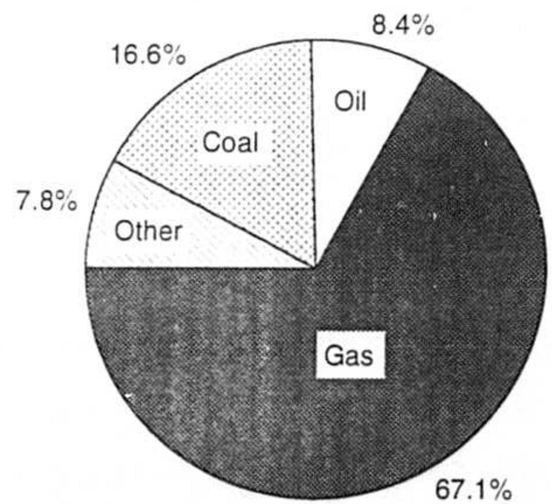
AKC#23 FUTR_GEN DRW

FLORIDA UTILITY CAPACITY EXPANSION PLANS BY FUEL TYPE: 1992 TO 2000

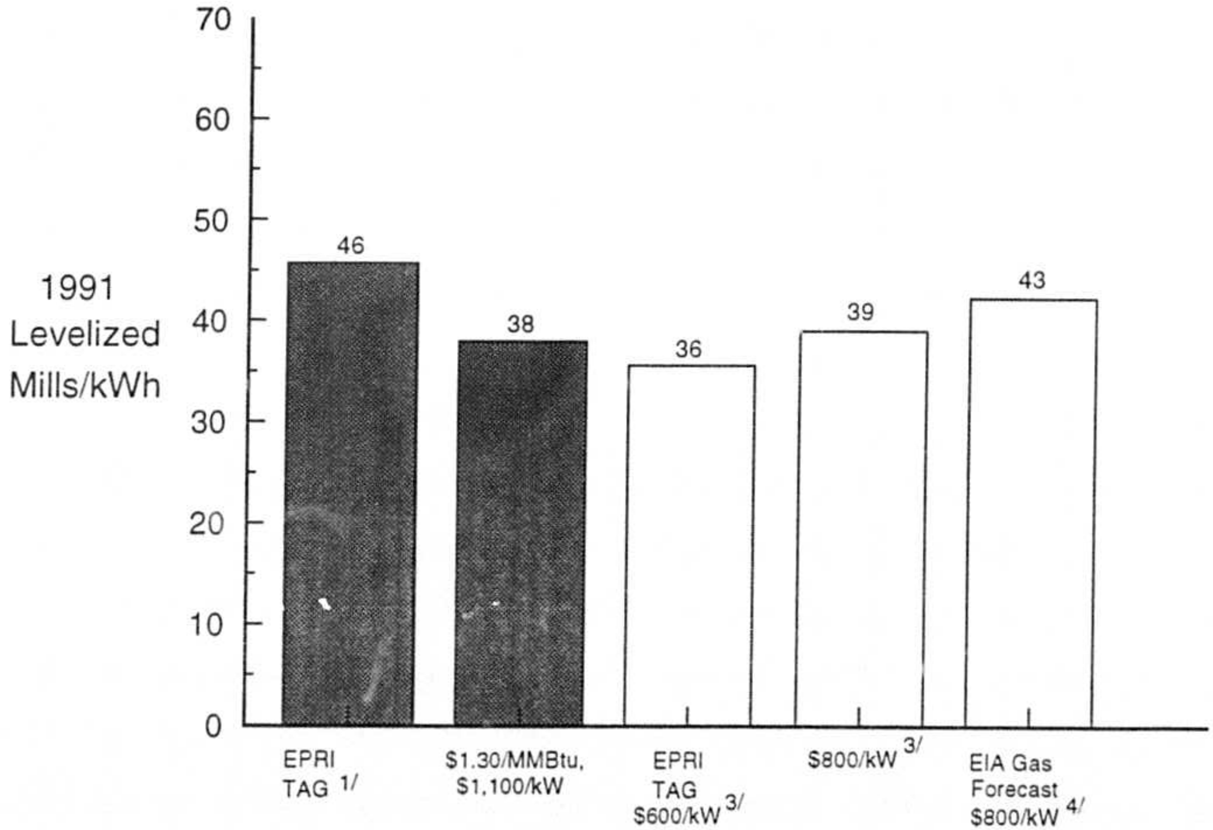


Total Capacity Additions = 9,856 MW

Source: Southeastern Electric Reliability Council, Coordinated Bulk Power Supply Program, April 1992.
North American Reliability Council, Electricity Supply & Demand, 1992
Totals may not add to 100% due to rounding.

LL:ANR:FLcapadd

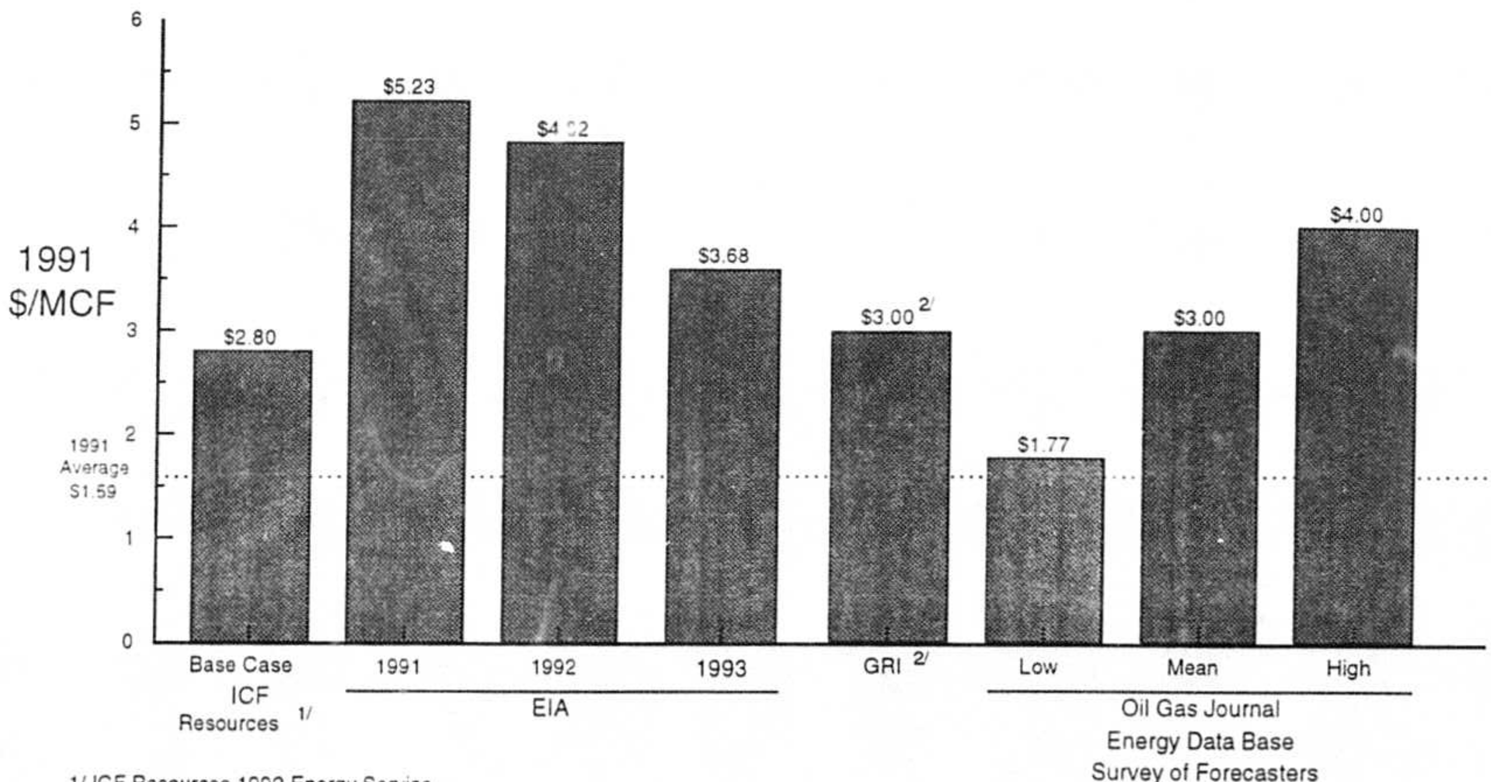
Costs of New Powerplant Options - 75 % Capacity Factor



1/ Delivered coal cost $1.65/MMBtu; $1,425/kW for capital cost
2/ Includes SO2 allowance cost of approximately 0.4 mills/kWh
3/ Levelized real annuity gas price of $3.25/MMBtu
4/ Levelized real annuity price of $3.75/MMBtu

AKC #23 BUSBAR.DRW

RANGE OF NATURAL GAS PRICE FORECASTS FOR 2010 — U.S. AVERAGE WELLHEAD PRICES



1/ ICF Resources 1992 Energy Service

2/ Wellhead price was calculated assuming an estimated national average of $0.65 per MCF transportation charge since GRI provides an average electric utility end-use price.

AKC #23 WELLHEAD DRW

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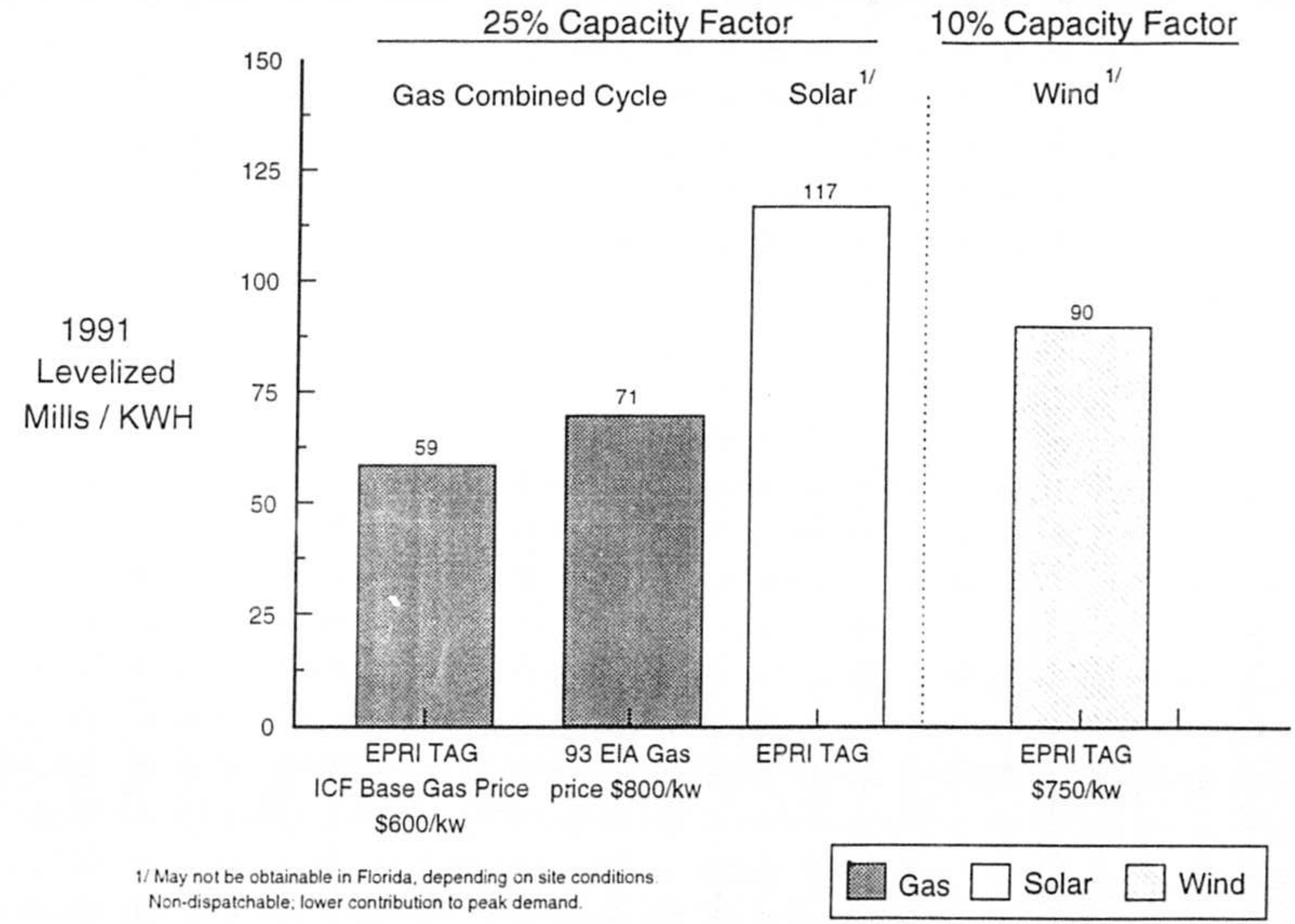
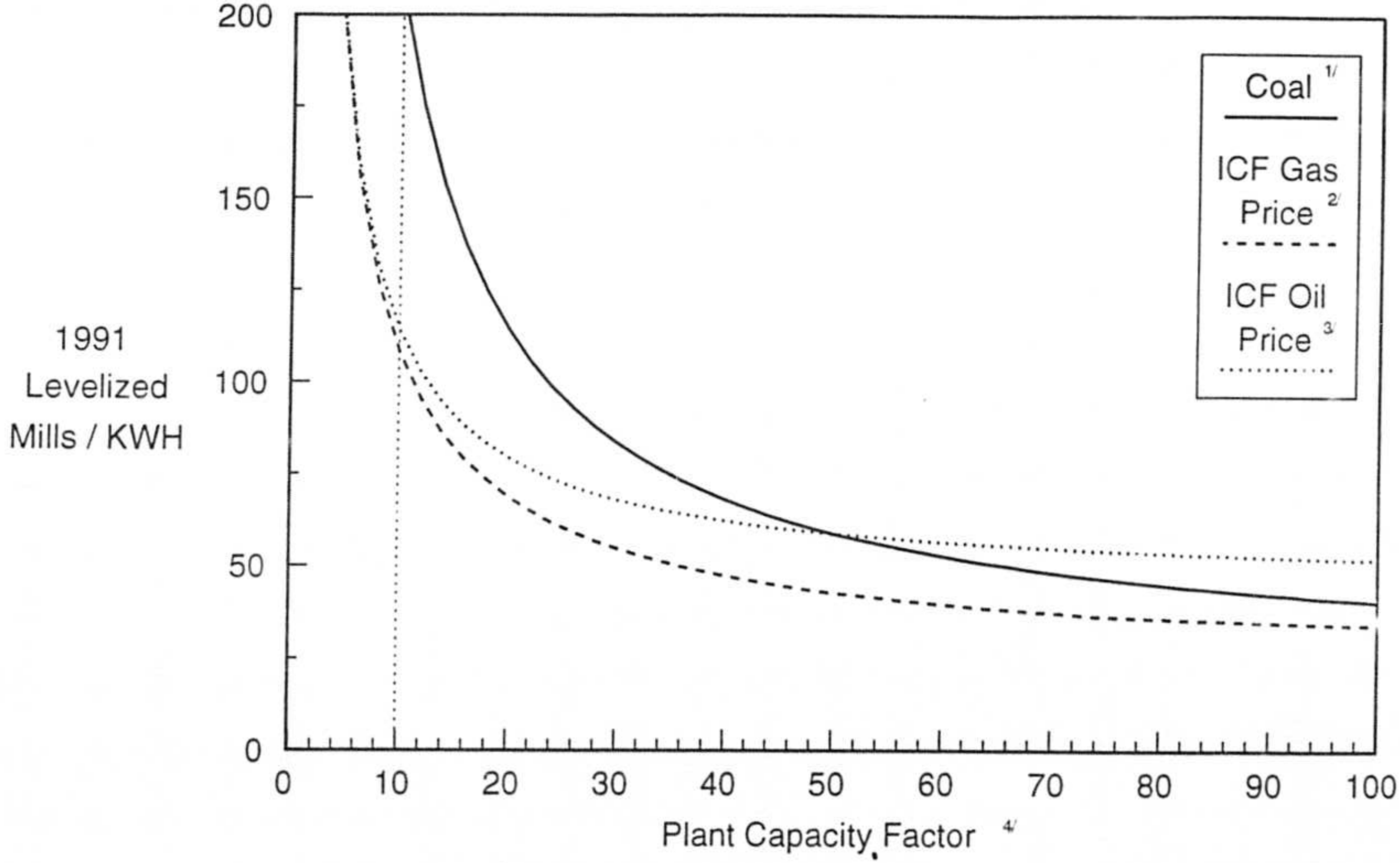
BUSBAR COSTS OF OPTIONS - 10% AND 25% CAPACITY FACTOR



1/ May not be obtainable in Florida, depending on site conditions.
Non-dispatchable; lower contribution to peak demand.

AKC/#23JNB RENEW DRW

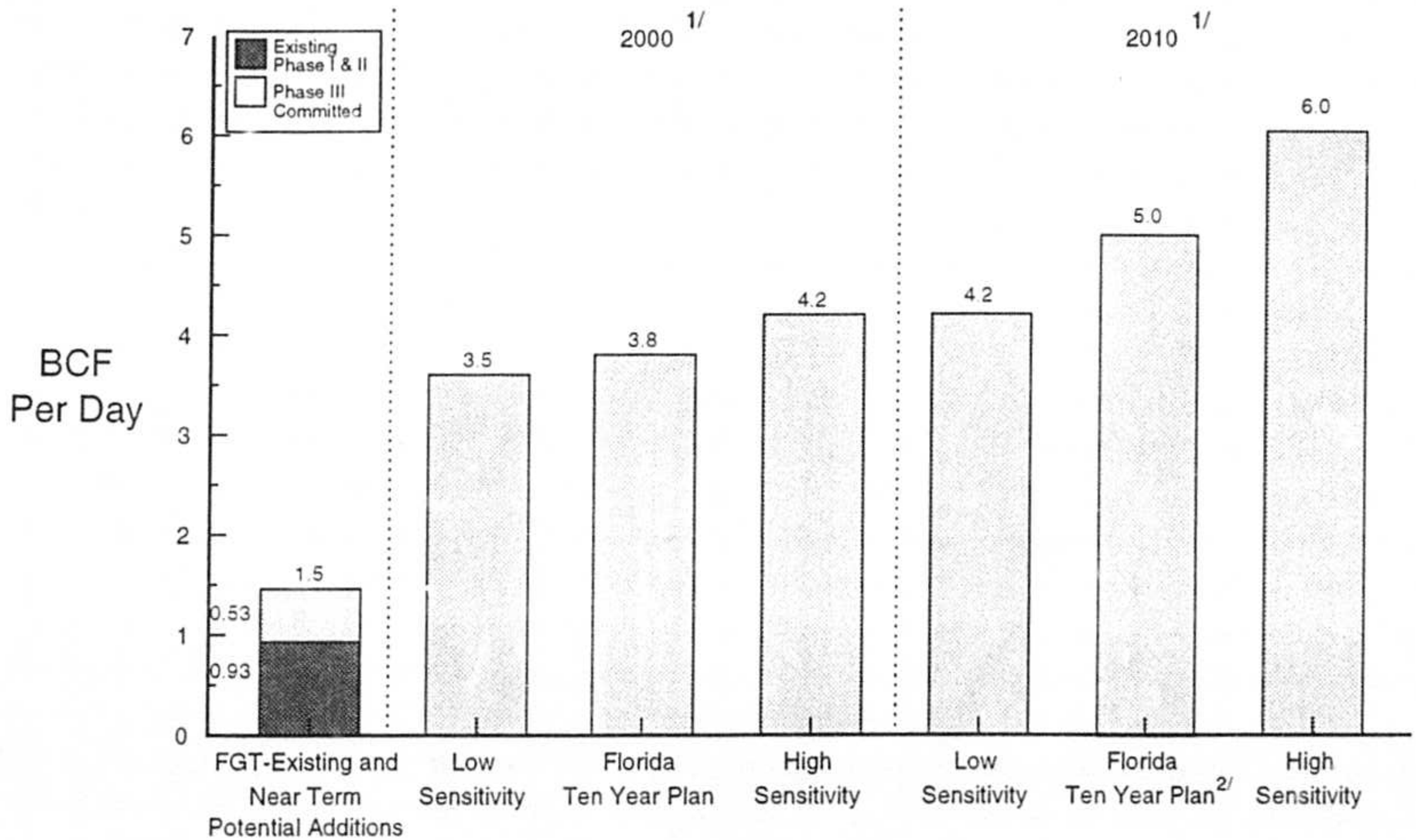
THE IMPACT OF PLANT UTILIZATION ON TOTAL PLANT COSTS



1/ 1.65 $/MMBTU coal, 1425 $/KW capital cost.
2/ 3.25 $/MMBTU gas, 600 $/KW capital cost.
3/ 5.72 $/MMBTU dist oil, 600 $/KW capital cost.
4/ Pipeline capacity is the lower of (plant capacity + 0.15) or 0.90.

AKO:DISK23:KWH-CAP.DRW

FLORIDA PIPELINE REQUIREMENTS - 2000 AND 2010



1/ Assumes non-electric sector gas demand is constant at 1990 level

2/ 1992-2001 electricity demand growth extended to 2010.

AKC #23 GAS_TRAN DRW

NATURAL GAS COMPETITION AT NEW POWERPLANTS — MARKET SEGMENTATION

Load Segment	Principal Competition	Gas Share
Base	Coal Versus Natural Gas	50%
Intermediate	Coal Versus Natural Gas	75%
Seasonal	Gas versus Distillate Oil	50%
Daily	Gas Versus Distillate Oil	0%

OIL VERSUS GAS IN 2000 AT EXISTING O/G POWERPLANTS

Segment (Average Capacity Factor)	Delivered Natural Gas Cost ($/MMBtu) - ICF Resources Base Case Annuity	Delivered Natural Gas Cost ($/MMBtu) - EIA Annuity	Delivered 1% Residual Oil Cost ($/MMBtu) - ICF Resources Base Case Annuity	Cost of SO2 Allowance Purchases ($/MMBtu)*	Total Cost of 1 % Residual Oil
Intermediate (50%)	4.00	4 50	4.88	0.10 - 0.25	4.98 - 5.13
Seasonal Peaking (25%)	4.53	5.05	4.88	0.10 - 0.25	4.98 - 5.13

* Levelized real annuities of $200 - $500 per ton starting in 2000.

FLORIDA TEN YEAR PLAN (2.6 PERCENT) ELECTRICITY SALES GROWTH SCENARIO - 2010

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	20.1	70-90%	4.6 - 6.9	50	100	0.4 - 0.6
Intermediate	17.5	50-60	17.5	75	70	2.6
Seasonal Peak Load	12.7	17-19	12.7	50	15	1.6
Daily Peaking	9.5	1	9.5	0	0	0
Total	59.8	45	44.3-46.3	0	N/A	4.6 - 4.8

HIGH ELECTRICITY SALES GROWTH SENSITIVITY - 2010

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	24.4	70-90%	8.2 - 10.2	50	100	0.7 - 0.9
Intermediate	20.7	50-60	20.7	75	72	3.0
Peak Load	15.0	17-19	15.0	50	5	1.9
Daily Peaking	11.3	1	11.3	0	0	0
Total	71.4	45	55.2 - 57.2	0	N/A	5.6 - 5.8

LOW ELECTRICITY SALES GROWTH SENSITIVITY - 2010

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	16.9	70-90%	1.7 - 3.7	50	100	0.14 - 0.3
Intermediate	14.6	50-60	14.6	75	55	2.3
Seasonal Peak Load	10.6	17-19	10.6	50	5	1.4
Daily Peaking	8.0	1	8.0	0	0	0
Total	50.1	45	34.9 - 36.9	0	N/A	3.8 - 4.0

FLORIDA TEN YEAR PLAN (2.6 PERCENT) ELECTRICITY SALES GROWTH SCENARIO - 2000

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	17.0	70-90%	2.0	50	75	0.2
Intermediate	12.8	50-60	12.8	75	66	1.9
Peak Load	10.5	17-19	10.5	50	5	1.3
Daily Peaking	7.5	1	7.5	0	0	0
Total	47.8	45	32.8	0	N/A	3.4

HIGH ELECTRICITY SALES GROWTH SENSITIVITY - 2000

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	18.6	70-90%	3.4	50	90	0.3
Intermediate	14.1	50-60	14.1	75	75	2.0
Peak Load	11.5	17-19	11.5	50	3	1.5
Daily Peaking	8.2	1	8.5	0	0	0
Total	52.4	45	37.5	0	N/A	3.8

LOW ELECTRICITY SALES GROWTH SENSITIVITY (1.7 PERCENT) - 2000

Load Segment	Total Capacity in Segment (GW)	Capacity Factor (%)	Potential Gas - New Plants and Existing O/G (GW)	Gas Share	% New Combined Cycle - Rest turbine and O/G steam	Bcf/day - 0.17 Bcf/day for Comb cycle, 0.26 otherwise
Baseload -	15.4	70-90%	0.5	50	0	0.07
Intermediate	11.6	50-60	11.6	75	63	1.77
Peak Load	9.6	17-19	9.6	50	2	1.25
Daily Peaking	6.9	1	6.9	0	0	0
Total	43.5	45	28.6	0	N/A	3.1