REDACTED VERSION

Florida Power
CORPORATION

COGENERATION REVIEW

An Assessment of Florida Power's Qualifying Facility (Cogeneration) Purchases

PRELIMINARY

Energy Distribution Department
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COGENERATION REVIEW

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EXECUTIVE SUMMARY

Florida Power Corporation (FPC) has contracted for nearly 1,100 MW of firm capacity from qualifying facilities (QFs) since the passage of the Public Utilities Regulatory Policy Act (PURPA) in 1978. PURPA and the FPSC rules which implemented PURPA, obligated electric utilities to purchase capacity from QFs if the capacity is needed and the QF payments are below the utility's avoided cost. Therefore, FPC signed the QF contracts based upon the avoided costs at the time. The overwhelming majority of the QF contracts are based upon pulverized coal plants while the majority of QFs are actually natural gas combined cycle plants. The price of natural gas has been lower than projected by FPC and the availability of gas transportation has increased since the QF contracts were signed. In addition, the capital and construction costs have significantly decreased. Therefore, at the present time, the QF contracts are not cost effective when compared to FPC built natural gas fired combined cycle units. Based upon current natural gas forecasts, the QFs in aggregate would require a reduction of 4% (high gas forecast) to 24% (expected gas forecast), to equal current avoided costs. The table below shows the comparison of the cost per MWH of QF capacity and energy versus the cost per MWH of a FPC natural gas combined cycle plant. The cost per MWH of the Miller Purchase is included for reference purposes only.

Year	$/MWH QF	$/MWH* FPC CC	$/MWH Miller Purchase	QF% of Total Capacity
1994	43.83	45.44	40.01	4.4%
1995	50.65	46.06	39.56	10.5%
1996	52.56	46.69	39.13	11.4%
1997	55.05	47.14	39.33	12.0%
1998	58.83	47.70	39.11	12.0%
*FPC's combined cycle cost assumes a new site				

The cost effectiveness of QF contracts will also be affected by many factors including the cost of natural gas and changes in environmental laws (e.g. CO_2 tax). The resources need to be assigned to properly evaluate and implement, if feasible, all of the options available to increase the cost effectiveness of the QF contracts. These contracts pose a significant threat to FPC's competitive position.

QF capacity payments are calculated based upon value of deferral methodology. This methodology calculates the value of deferring the need for the construction of capacity annually. Therefore, the cost starts lower than traditional revenue requirements but increases by approximately 5% per year. Conversely, traditional revenue requirements start higher than value of deferral payments but decrease over time.

The net present value as of January 1, 1994, of all of the QF capacity payments is $2.7 billion, assuming an interest rate of 10%. FPC has concerns that these QF contracts may lower our current (Standard & Poor's) AA-bond rating. Standard & Poor's (S & P) methodology states that these off-balance sheet obligations should be considered to be debt equivalents. These obligations are adjusted by a risk factor which ranges from 10% minimum up to 50% for take-and-pay contracts. The risk factor is multiplied by the net present value (NPV) of the QF contracts to determine the utilities imputed debt. FPC cogeneration contracts should be assigned the lowest risk factor of 10%.

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In addition, FPC has become concerned about FPC's ability to accept this QF capacity during periods of minimum load. FPC's minimum load is approximately 1,800 to 2,000 MW, which occurs during mild weather conditions. This entire load could be served by FPC's nuclear plant and the QFs if the QFs did not reduce their capacity. During these periods, the output of FPC's steam units would have to be reduced as much as possible or cycled off. Cycling off steam units increases their O&M costs and renders them unavailable to meet the rapidly growing load a few hours later; forcing FPC to serve the load uneconomically. FPC has agreements in place, and is continuing negotiations with the QFs, to resolve this problem without additional payments to the QFs.

For all of the above reasons, FPC has investigated a buy out of some of the QF projects such as Auburndale, Lake Cogen and Pasco Cogen. The FPC investigation included three different scenarios. These were (1) operating as a QF project, (2) operating as a utility generator or (3) a buy out of FPC's contractual obligation. At this time, it is not financially viable to purchase these projects under these scenarios. If circumstances change (e.g. natural gas prices), these and other projects should be reevaluated. A copy of these analyses may be obtained from Robert Dolan, Manager of Cogeneration Contracts and Administration. To date, FPC considered it uneconomical to buy out any QF contract.

FERC's PURPA regulations, adopted by the Florida Public Service Commission. provide that approved QF rates do not become unjust and unreasonable because the utility's avoided cost at the time the QF comes into service is different than the utility's avoided cost at the time the QF contract was entered into. Therefore, FPC must find another method to reduce the cost of QF contracts. One method could be to buy down QF contracts.

When the contract with Pasco Cogen (106 MW) is taken as an example, the payment required to reduce their capacity payment to match FPC's embedded cost is $46 million. This figure assumes a 20% discount rate and uses FPC's expected fuel forecast. Buy down costs can be dramatically altered by the fuel forecast used, the QF's interest rate, the QF's expected rate of return, inflation, and other factors.

Many of the QF contracts require that the QFs ability to deliver their capacity shall not be encumbered by interruptions in their fuel supply. FPC has therefore placed one QF in default (Orlando CoGen, 72 MW) because they do not have a back up fuel. Two other QFs (Tiger Bay, 217.75 MW and Orange Cogen, 74 MW) have been notified that they will be in default if they do not have a back up fuel supply in place when they begin to receive capacity payments.

FPC is not currently pursuing additional capacity from non-utility generation sources. However, recommendations are made in this review should additional contracted capacity be required or mandated.

The FPSC has approved a bidding rule that only applies to generation which requires a determination of need (steam greater than 75 MW) and may be waived. The FPSC rule is as follows:

> *"Rule 25-22082(9) The Commission may waive this rule or any part thereof upon a showing that the waiver would likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers or is otherwise in the public interest".*

Peakers and potentially repowering may not require bidding. The Governor and Cabinet did not endorse the PPSA's task recommendation that all capacity additions be bid.

BACKGROUND

Please note that the total cogeneration capacity stated at various time in this review may vary depending on the subject. This variance is due to the fact that the cogeneration contracts have the ability to adjust their committed capacity. Depending on the application, the most appropriate total capacity figure will be used.

Review of the Requirements of the Public Utility Regulatory Policies Act

In 1978, the Public Utility Regulatory Policies Act (PURPA) was enacted and then amended in 1980. PURPA's constitutionality was challenged in Mississippi. Upon appeal, the U.S. Supreme Court found that PURPA was constitutional in 1982. Section 210 of that statute addresses cogeneration and small power production, the primary focus of this section. See Appendix 8 for a copy of PURPA.

Congress' goal in passing PURPA was to reduce the U.S. dependence on foreign oil by diversifying energy supply and reducing consumption. PURPA encouraged small alternative power producers (including hydro and renewables), and cogeneration resources. Congress sought to overcome the reluctance of utilities to deal with alternative power providers and conservation by requiring utilities to purchase from a class of defined small power production and cogeneration facilities that could achieve qualifying facility (QF) status. Congress also required utilities to interconnect and to supply backup power. As for the reluctance of alternative producers to become regulated by virtue of selling power in a traditionally regulated industry, congress exempted QFs from most of the regulatory burdens including Public Utility Company Holding Act (PUCHA) placed on investor-owned utilities.

Congress divided QF regulation between the Federal Energy Regulatory Commission (FERC) and the state public service commission where the purchasing utility is located. It is important to keep in mind that in most cases the sale of QF power to an electric utility is a wholesale, not a retail, transaction. As such, jurisdiction normally would lie with FERC. However, PURPA directs that certain Federal regulatory functions, such as the determination of avoided costs, be delegated from FERC to the states. PURPA gives FERC broad discretion to establish, through its rules and regulations, the parameters of the economic transactions between electric utilities and QFs. In turn, the individual states are bound to follow these FERC requirements.

A QF can be either a cogenerator or a small power producer. As a general matter a cogeneration facility simultaneously produces electric energy and forms of useful thermal energy, such as heat or steam used for industrial, commercial, heating or cooling purposes. A small power production facility is a facility that produces electricity from biomass, waste, hydro, renewable resources, or geothermal energy.

Criteria for Cogeneration Facilities

PURPA defines a qualifying cogeneration facility as a cogeneration facility which FERC determines by rule meets size, fuel use and fuel efficiency and such other requirements as FERC may prescribe, and is owned by a person not primarily engaged in the generation or sale of electric power. This broad definition leaves significant discretion in the hands of FERC.

FERC's rules define a qualifying cogeneration facility in terms of a topping-cycle and bottoming-cycle facility. A topping-cycle facility is one in which the energy input into the facility is first used to produce useful electric power, and the waste heat from power production is then used to provide useful thermal energy. A bottom-cycling facility involves the reverse process. The energy input is first applied to a useful thermal energy process and the emerging waste heat is then used to produce electricity. Most cogeneration facilities, such as natural gas-fired combined cycle facilities, are topping-cycle. An example of a topping cycle is Pasco Cogen Limited in Dade City. Pasco Cogen is a natural gas combined cycle plant. Two aero-derivative gas turbines are fired by natural gas. The exhaust heat is then captured in a heat recovery steam generator (HRSG). The steam generated in the HRSG produces electricity from a steam turbine. Low pressure steam is taken off the steam turbine and used in the Lykes Pasco citrus processing plant.

Bottoming-cycle facilities tend to built when there is an established industrial process producing waste heat, such as the process used to produce sulfuric acid. An example of a bottoming-cycle cogenerator is Cargill Fertilizer (formerly Seminole Fertilizer). The Cargill Fertilizer plant makes sulfuric acid from sulfur. This chemical (exothermic) process produces excess heat which is captured in a recovery boiler; the steam from the boiler is used to generate electricity.

For topping-cycle facilities, the useful thermal energy output of the facility must, during any calendar year, be no less than 5 percent of the total energy output. In addition, the useful power output plus half of the useful thermal energy output for a natural gas or oil facility, must be greater than 45% of the total energy output of the facility. If the useful thermal energy output is greater than 15% of the total energy output of the facility, then the efficiency standard is 42.5%.

FERC opinions generally have provided that a thermal output is "useful" if it has an independent business purpose with some economic justification. FERC has found business purposes to be presumptively useful when use of a facility's thermal output constitutes a common industrial or commercial process.

FERC rules allow FERC to waive the operating and efficiency standards contained in its rules if FERC finds that a facility will produce significant energy savings. For example, FERC has waived its thermal host requirements applicable to cogeneration facilities when QFs have temporarily lost their thermal hosts but are actively searching for a replacement host.

Criteria for Small Power Production Facilities

PURPA's definition of a small power production facility is essentially the same as the broadly-worded definition for qualifying cogeneration facilities, leaving significant definition discretion to FERC. A qualifying small power production facility is one which FERC determines meets such fuel use, fuel efficiency and reliability requirements as FERC prescribes by rule. FERC's rules provide that the power production capacity of a small power production facility, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 MW. Facilities are defined to be at the same site if they are located within one mile of each other. In 1990, Congress lifted the 80 MW limitation for small power producers that are fueled by certain waste products or by renewable energy. Generally these waste products are byproducts of industrial processes, such as coal waste. Likewise, the 80 MW limit does not apply to tire-burning plants. However, the limit still applies to municipal solid waste (MSW) facilities.

FERC's rules provide that at least 75 percent of the primary energy source of a small power production facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof. The rules further provide that the use of oil, natural gas and coal as a fuel may not in the aggregate exceed 25 percent of the total energy input of the facility during any calendar year.

Criteria For QF Ownership

PURPA provides that a cogeneration or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration or small power production facilities). Under FERC rules, facilities are considered owned by a person primarily engaged in the generation or sale of electric power if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company or companies, primarily engaged in the sale of electricity, or any combination thereof. QF status is based on the sale of net output from the facility. That is, for purposes of size, efficiency and ownership, the power utilized on site is subtracted from the gross output of the facility at the point of sale.

Obtaining QF Status

FERC's rules provide that QFs must apply to FERC for certification. This is typically done prior to project financing and construction. Hence, applications usually describe a *proposed* facility. FERC rules require that applications must contain enough information for FERC to determine whether PURPA's qualifying facility requirements will be met. FERC generally will accept the representations of the applicant as true. FERC's rules provide that QF status may be revoked if a QF which has been certified fails to comply with any statement contained in its application for certification. For this reason QFs sometimes amend their applications and request FERC recertification during the course of their project development.

Regulatory Exemptions Enjoyed By QFs

QFs are generally exempt from the Federal Power Act, the Public Utility Holding Company Act, and most state regulations. The only significant portions of the Federal Power Act from which QFs have not been exempted involve interconnection and wheeling, and are discussed below. If a project loses QF status during its lifetime, it is subject to regulation as a public utility.

State Regulation Of QFs

PURPA directs FERC to issue rules "as it determines necessary to encourage cogeneration and small power production," and which also require utilities to offer to purchase electric power from QFs. PURPA directs that in turn, each state regulatory authority charged with regulating electric utilities must "implement" PURPA rules. FERC issued its rules in 1979. In 1981, the Florida Public Service Commission (FPSC) adopted FERC's rules and issued additional, complementary rules of its own. The FPSC revised its cogeneration and small power production rules in 1984 and 1990. These rules are discussed in the section on the development of cogeneration at FPC.

Utility Obligation To Purchase QF Power

PURPA directed FERC to enact regulations which require all electric utilities, not just investor-owned utilities, to purchase electricity produced by QFs. FERC's regulations provide that each electric utility shall purchase any energy and capacity made available to it from a QF to which the utility is directly interconnected, or from a QF that causes such energy or capacity to be delivered to the utility. However, FERC's rules also provide that if there are operational circumstances in which purchases of QF power will result in the utility bearing costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, the utility will not be required to purchase power from QFs.

Rates For Purchases By Electric Utilities From QFs

PURPA provides that various traditional regulatory requirements, such as the just and reasonable standard and the public interest standard, govern rates for sales by QF to electric utilities. PURPA also requires that utilities purchase at rates which shall not discriminate against QFs, and that such rates shall not exceed the incremental or avoided cost to the electric utility of alternative electric energy. The incremental cost of alternative electric energy is statutorily defined as the cost to the electric utility of the electric energy which, but for the purchase from the QF, the utility would have generated or purchased from another source.

The states administratively establish the avoided cost rates that utilities pay for power purchased from QFs, in accordance with the requirements set forth in FERC's rules. FERC does not prescribe a specific methodology for the states' calculations of avoided cost. However, FERC regulations direct that in determining avoided costs, utilities shall, to the extent practicable, take into account the availability of capacity or energy from a QF during daily and seasonal peak periods, the ability of the utility to dispatch the QF, the terms of the purchase contact (including its duration, termination notice requirements and sanctions for non-compliance), the coordination of scheduled outages, the usefulness of QF power during utility system emergencies, the individual and aggregate value of energy and capacity from QFs on the utility's system, the smaller capacity increments and the shorter lead time available with additions of capacity from QFs, and the ability of the utility to avoid costs by deferring capacity additions, reducing fossil fuel use, or lowering line losses.

FERC's rules explicitly provide that nothing in the rules requires an electric utility to pay more than avoided cost. However, the rules stipulate that a rate set at full avoided cost satisfies the just and reasonable and public interest standards. Rates may be less than avoided cost if the state public service commission determines that a lower rate is just and reasonable, in the public interest, and is sufficient to encourage cogeneration and small power production. In a case in which the rate for purchases are based upon estimates of avoided costs over the term of a contract, the rates do not violate FERC rules if they differ from avoided costs at the actual time of delivery.

The rates paid by utilities to QFs contain an energy and capacity component. FERC's rules provide that utilities must only pay for the capacity value of power purchased when the purchase allows the utility to reduce its own capacity-related costs by deferring construction or firm power purchases. FERC's rules provide that rates for as-available energy purchases, at the QFs option, can be based on the avoided energy cost at the time of delivery or on an avoided energy cost calculated at the time the utility contracts to receive the energy over a specified future term.

Utility Obligation To Sell To QFs

PURPA directed FERC to enact regulations which require all electric utilities to offer to sell electricity to QFs. These rates, like purchase rates, must be just and reasonable, in the public interest and non-discriminatory. FERC requires that upon request of a QF, each electric utility shall provide supplementary power, back-up power, maintenance power or interruptible power. State public service commissions may waive the requirement to supply any of these four services if compliance would impair the utility's ability to render adequate service to its customers or place an undue burden on the utility.

Interconnection

FERC's regulations provide that electric utilities must agree to interconnect with any QFs in their service territory, unless such interconnection would expose the utility to additional regulation under the Federal Power Act. Utilities also must offer to operate in parallel with a QF. FERC rules also provide that interconnection costs, including costs of connection, metering, transmission, distribution and safety equipment be borne by the QF.

Wheeling

PURPA obligates electric utilities to offer to purchase QF power made available to them. It does not restrict this obligation to purchases of power from QFs to which the utility is directly interconnected. FERC's rules provide that if a QF agrees, an electric utility directly interconnected to that QF may transmit the energy or capacity to any other electric utility, which utility in turn is obligated to purchase the power or energy. The FPSC has required utilities in Florida to wheel electricity for QFs since 1984 utilizing the rates, terms, and conditions specified by FERC.

Under the Energy Policy Act of 1992, any individual or company generating wholesale power can apply to FERC for an order requiring an electric utility to provide transmission services. The order may also require the utility to expand its transmission capacity.

Retail Sales and Self-Service Wheeling

Florida law only allows for retail sales from a QF to the thermal host if the thermal host is a government body (e.g. the University of Florida and Florida State University). Self-service wheeling is prohibited unless the FPSC finds that provision of this service is not likely to result in higher cost electrical service to the general body of ratepayers.

There are two retail sales cases that FPC has been involved in with QFs. In the first, Timber Energy requested permission to serve the industrial park in Telogia where they are located. The FPSC ruled that Timber Energy could serve these customers but, if they did, they would have become regulated by the FPSC. Currently, there are no other businesses in the industrial park and Timber Energy is not interested in becoming a regulated utility.

In a second case, Mulberry requested permission to serve its thermal host as part of a fixed rent payment. The FPSC staff has recommended that this is a retail sale and it should not be allowed. The FPSC will vote on this issue during the upcoming Proposed Agency Action (PAA) scheduled for February 1, 1994.

There have been at least two requests for retail wheeling involving QFs. Both cases were denied by the FPSC as not being cost effective for the general body of ratepayers. These were the Metro Dade Downtown Government Center (FP&L) and W.R. Grace (TECO). In both cases, the QFs argued that it was cost effective for them to build either a transmission line or distribution line to the load thus bypassing the utility in question. The

FPSC ruled that this should not be a determining factor in whether retail wheeling should be ordered.

Exempt Wholesale Generators and Independent Power Producers

An exempt wholesale generator (EWG) is a defined term under the recently-enacted Energy Policy Act of 1992 (EPACT): *any person engaged, directly or indirectly through affiliates, and exclusively, in the business of owning and/or operating all or part of a facility used for the generation of electricity exclusively for sale at wholesale.* Additionally, Section 712 of EPACT requires state regulatory commissions to perform a general evaluation of:

1. The impact of purchased power contracts on a utility's cost of capital and retail rates;

2. Whether Non-Utility Generators (NUGs) have an unfair advantage over utilities or threaten system reliability because of their debt leveraging;

3. Should regulators preapprove power purchase contracts; and

4. Should regulators require assurances of adequate fuel supplies.

The FPSC has decided to evaluate these impacts on a case-by-case basis.

EWG status can be obtained only through application to FERC. Owners of EWGs are not subject to the Holding Company Act, and are not regulated as persons primarily engaged in the sale or transmission of electricity under the Federal Power Act. Unlike the QFs, electric utilities are not obligated to offer to purchase from EWGs. Thus, it is expected that EWGs will compete strongly with IPP's and QFs on price and terms and conditions of sale.

Utilities may not contract purchased power from an affiliated EWG unless the utility receives a state public service commission order finding that the transaction will benefit consumers, does not violate state law, will not provide the EWG with any unfair advantage by virtue of its affiliation, and is in the public interest.

The term independent power producer (IPP) is not a defined term under the Federal Power Act, PURPA, or EPACT. An IPP is commonly considered to be a seller of electricity at wholesale which fails to qualify as an EWG. The most significant legal consequence of failure to qualify as a QF is that electric utilities are not obligated to purchase the output of IPP's and EWG's. Failure to qualify as either a QF or EWG also means that the generator is not exempt from the Holding Company Act, and is subject to regulation under the Federal Power Act.

Because utilities are not required to purchase the output from IPP's, those facilities, like EWGs, must compete strongly with QFs on price and terms and conditions of sale. However, the presence of IPPs in the wholesale market likely will diminish over time with the advent of EWG status created by the Energy Policy Act of 1992. Independent generators are expected to strive for EWG status in order to avoid the strictures of the Holding Company Act.

FERC recently abandoned a proposed rulemaking, instigated in 1988, which would have exempted IPPs from many of the regulatory burdens of the Federal Power Act. However, in a series of case-by-case decisions, FERC has accomplished much of the IPP deregulation that it proposed. The most significant Federal Power Act burden as far as IPPs are concerned, is the requirement that all sellers of power must sell at a "just and reasonable" rate. Traditionally, FERC has required that rates be cost-based in order to be just and reasonable. However, FERC case law establishes that FERC will approve an IPP rate if it determines that the IPP lacks market power, and that the rate is market-based; that is, established through bidding or arms-length negotiation. EWGs are subject to the same just and reasonable standard as IPPs, therefore, it is anticipated that FERC will approve EWG rates on a similar basis.

Development of Cogeneration at FPC

1. Pre-PURPA (prior to 1978)

   Prior to the passage of PURPA, Florida Power Corporation had three contracts with cogenerators. Two contracts were for self-service generation only, with no sales to FPC. These were both for 1 MW and were located at the University of Florida and Minute Maid Dunedin (later H.P. Hood Company). The third contract was with St. Joe Forest Products. This contract allowed St. Joe Forest Products to delivery power to FPC (City of Port St. Joe) under emergency conditions. The interconnection was also used to provide backup power to St. Joe Forest Products.

2. Post PURPA pre-FPSC rules (1978-1982).

   During the period of rule development between the passage of PURPA and the completion of the Florida rules in 1982, FPC negotiated with prospective cogenerators in the spirit of PURPA and under terms of the anticipated Florida rules. These contracts can be separated into two types:

   a. Interconnection without sales to FPC.

      Citrus World #1 - November 1979
      Ben Hill Griffin - November 1981
      Buckeye Cellulose (Procter & Gamble) - August 1980

b. As-available contracts signed during this period.

Occidental Chemical Swift Creek #2 - January, 1980
US AgriChem - October, 1982
Pinellas Waste Recovery #1 - May 13, 1980

During this same period, negotiations were held with Biomass Monticello and Biomass Madison, which resulted in interconnections to purchase as-available energy from each of these 7.5 MW plants.

3. FPSC rules for as-available energy implemented (1982-1984).

The FPSC implemented rules for the sale of as-available energy in 1982. Any existing QF contracts that benefited from the FPSC rules were amended to incorporate those rules. Credit for variable O&M charges and for avoided plant start-up were added. The contract for Pinellas Waste Recovery was not modified since it was based on a formula for determining avoided cost that gave them more revenue than the newly defined as-available rate (COG-1).

The only contract signed during this period was for 20 MW additional capacity at the Pinellas Solid Waste Plant. This was signed in December, 1983.

4. FPSC rules for firm contracts implemented (1984-1990).

A statewide avoided unit was used as a basis for pricing capacity credits for cogenerators under the COG-2 firm rate. The draft of the rules was based on the statewide avoided unit being the next major generating unit to be built in the state by any of the investor owned utilities. Tampa Electric Company was planning to build two 700 MW coal fired power plants and the FPSC indicated that they were considering designating those as the statewide avoided unit in the draft. However, before the rules could be finalized, Tampa Electric withdrew their plans for the 1,400 MW facility and substituted a smaller combined cycle unit. In reconsideration of the rules, the FPSC determined that it would be in the best interest of the state to have a large coal fired unit rather than several small units planned by each of the utilities. Therefore, two fictitious 1992, 700 MW coal fired generating plants were designated as the statewide avoided unit and the pricing was based on estimates of the cost of building a plant at that time, along with escalations in capital and O&M costs utilizing TECO Big Bend #4 coal prices.

Based upon the 1992 statewide avoided unit, Florida Power Corporation developed a standard offer contract effective April 30, 1984, and several small power producers were proposed. However, only one contract was actually signed and that was with Timber Energy for 12.765 MW. The Biomass units were in bankruptcy and attempted to recover in order to sign a firm contract under the 1992 unit pricing. However, they were unsuccessful. A number of other proposals were made but none came to fruition while the 1992 unit was in effect. A contract was negotiated with the Corporation for Future

Resources (CFR) for 50 MW under the COG-2, Option B pricing schedule which allowed for the financial parameters to change annually requiring a recalculation of the capacity payment each year.

The next unit that was selected as a statewide avoided unit was a 1995 pulverized coal unit. This was a single 500 MW unit coal fired unit with its coal pricing based upon deliveries to Tampa Electric Big Bend #4. Signed up under this 1995 unit were, Bay County Resource Recovery, Biomass Madison and Jefferson (later sold to LFC), Lake County Resource Recovery, Pasco County Resource Recovery, and Pinellas Mid County Resource Recovery.

Until this time, all QF payments were assigned a risk factor of 0.80 because of the uncertainties involved. The risk factor reduced the capacity payments to 80% of the avoided costs. During the period that the 1995 statewide avoided unit was in effect, a law was passed granting the waste incinerators signed up under the standard offer pricing to have the 80 percent risk factor increased to 100 percent. This raised the 1995 price per KW from $16.04/KW/Month to $20.06/KW/Month for these incinerators, and changed the price of FPC's contracts with Pinellas County, Pasco County, and Lake County. Bay County was not affected because it was a special contract with negotiated rates for payment of early front loaded capacity payments which had already begun.

Contracts for three equally sized units totalling 156 MW were negotiated with General Peat Resources based on the 1995 unit. These had some front end loading of the capacity payments, and also required a higher on-peak capacity factor than did the standard contract (these contracts later returned to a normal payment schedule). After we signed these contracts, we petitioned the FPSC to closeout the 1995 unit, because 500 MW had been signed against it. However, FPC was unaware that another contract had been signed by Florida Power & Light. Because this contract had been signed, it did not allow enough capacity to satisfy all three of the General Peat contracts. Contracts for the second and third units were held in abeyance but were eventually approved against the new statewide avoided unit. Timber Energy signed an additional contract for 6 MW under the pricing of the 1995 unit, and CFR signed for an additional 24 MW under the 1995 pricing.

In 1989, the FPSC decided that the next statewide avoided unit would be a 385 MW FP&L combined cycle unit with a 1993 in-service date. This 1993 plant was converted to a 1996 500 MW coal plant by the FPSC on their own motion in October of 1989. The 40 MW Pinellas County Resource Recovery (PCRR) contract includes the 1995 coal payment schedule if the plant is completed before 1995. However, if the plant is completed during 1995, then the payments for the 1996 coal plant will apply. If the PCRR facility is completed after January 1, 1996, the then current avoided unit payments will apply.

5. FPSC "new" rules for firm contracts (1990-present).

As a result of the oversubscription of the 500 MW statewide avoided unit, the FPSC amended the state rules. The new state rules are based on a utility specific unit. See Appendix 4 for the FPSC's current cogeneration regulations.

6. 1991 Bid for QF Capacity

A change in our forecasting parameters in 1990 indicated that we had some capacity shortages, particularly in the 1993-1994 time range. In addition, FPC was developing two cogeneration projects with Peoples Gas, and needed the negotiations for these projects to be kept at "arms-length" to avoid a conflict of interest. These reasons, along with FPC's desire to build its own capacity in Polk County without bidding, resulted in FPC issuing a RFP in January 1991, for capacity that could be on-line prior to December 1993. A contract format was developed based on a coal unit priced at 1991 prices for offer to qualifying facilities that could be on-line by the end of 1993. Approximately 450 MW was needed, and more than double this amount was proposed to FPC. However, the decision was made to contract for approximately 600 MW to allow for a 25% dropout rate. This dropout rate was considered conservative. Between October 1990, through March 1991, contracts were signed with Seminole Fertilizer (47 MW), Lake Cogen Limited (102 MW), Pasco Cogen Limited (102 MW), Orlando CoGen Limited (72 MW), Royster Phosphates (28 MW), El Dorado Energy (103.8 MW), Mulberry Energy (72 MW), Dade County Resource Recovery (43 MW), and Ridge Generating Station (36 MW). Also negotiated on a similar basis, was EcoPeat (36.5 MW).

Currently, the only dropouts that we have had is a reduction of 32 MW of capacity from Seminole Fertilizer, and the indefinite postponement of 40 MW that had been contracted earlier with Pinellas County. CFR had been considered "dead" and its capacity was not included in the satisfaction of our needs. CFR had an option B contract for 50 MW based on the 1992, unit and a 24 MW contract based on the 1995 unit. The contract was for service at a specific location (near Drifton) and it was later determined that the contract potentially caused a negative impact on our ability to import the Miller purchase from the Southern Company. We did not give CFR permission to move the contract to the Hinson area and it appeared the project would fold at its contractual location. However, there was considerable interest in CFR by the FPSC; subsequently an FPSC order was made to accommodate CFR. This resulted in FPC and CFR negotiating a dispatchable contract based on the 1991-1995 unit. This contract did not allow a capacity redesignation of +10% that was allowed in the contracts written as a result of the 1991 bid. The net effect of these changes from the original strategy is the addition of CFR substantially equals the reduction in Seminole Fertilizer and the removal of the 40 MW of Pinellas County capacity from our forecast.

7. Polk County Combined Cycle Need Case Proposed Units 1-4

FPC petitioned the FPSC to build 4-235 MW combined cycle units in Polk County. The FPSC approved the certificate of need for units 1 and 2, but deferred action on units 3 and 4. This was done because there is adequate time to consider these units without impacting construction schedules, and too many uncertainties including load, fuel, and conservation forecasts. In fact, since the FPSC ruling, the projected load growth has declined.

Pursuant to Order No. 25805, Docket No. 910759-EI, Page 43, the FPSC stated "Florida Power has demonstrated that it reasonably considered capacity purchases from other utilities and non-utility generators to meet future generation needs. In the past, Florida Power has purchased significant amounts of QF capacity..."

8. 1997 Combustion Turbine Standard Offer

It was assumed that we would have our 25 percent dropout rate on future projects when the need for a 1997 combustion turbine rated at 150 MW was determined. Based on this assumption, we had 80 MW of standard offer and 70 MW of negotiated contracts. A standard offer contract of 74.9 MW was accepted during a two week open season. After an extensive evaluation, Panda Energy was selected among the several standard offer contracts received. That left 5.1 MW of standard offer open. The remaining 70 MW has been removed from the plan due to the QFs that did not fail as expected. See Appendix 2 for a complete list of QF projects.

9. New Capacity Needs

FPC's Ten-Year Site Plan forecasts the energy and capacity requirements for the company during the next ten years and proposes generating capacity additions and removals to meet these needs. It takes into account the contribution from the qualifying facilities under contract. In the 1993 Ten-Year Site Plan, the only planned generating capacity not already under contract or under construction is the Polk County Units 1 & 2. The Ten-Year Site Plan was filed March 26, 1993, with the Bureau of State Planning Division of Resource Planning and Management of the Department of Community Affairs. Currently, FPC is updating the Integrated Resource Plan and is expecting to file it with the FPSC during March 1994.

10. FPSC Rules for Firm Contracts

The FPSC has proposed a hearing in 1994 to revise the cogeneration rules based upon the recently adopted bidding requirements. The initial workshop is scheduled for February 14, 1994.

Bidding Rules

On December 7, 1993, the FPSC adopted a rule which requires electric utilities to engage in a competitive bidding process prior to filing a need determination under the Power Plant Siting Act (PPSA) unless the utility can demonstrate that competitive bidding is not in the public interest. Prior to the passage of this rule, the FPSC's informal guidelines encouraged investor-owned utilities to bid new generation. These guidelines generally did not result in new baseload projects being bid because utilities successfully justified why bidding was not the best decision for new generation. This process did not appear to be a major problem, until the FP&L Cypress Energy project. At that point, the FPSC decided to issue a proposed bidding rule. Concurrently, the Governor appointed a task force to review the PPSA. The competitive bidding issue is one of many areas reviewed and the task force considered whether legislative changes should be recommended.

The FPSC's approved bidding rule generally provides the following:

- Electric utilities must establish and use a fair selection process for new generation if the generation addition requires certification under the PPSA.

- Electric utilities can use any selection method, although bidding is encouraged.

- The electric utilities have an obligation to serve and an ensuring responsibility to plan, develop, and manage its resources.

- If purchased power is not found to be in the best interest of ratepayers, the electric utility must provide the FPSC with an explanation.

- Bidding is encouraged for all generation which requires a certificate of need. A certificate of need is currently required for all generators with a steam cycle capacity greater than 75 MW.

- If a certificate of need is not required (i.e. combustion turbines, repowering or combined cycle units with a steam cycle of less than 75 MW), then bidding is not mandatory.

Specifically, the rule would:

1. Require all electric utilities (IOU's, coops and munis) to issue a Request for Proposals (RFP) prior to filing a petition for determination of need, unless to do so is not in the best interest of the utilities ratepayers.

2. Require each utility RFP to identify the MW size, timing, and price and non-price attributes of the generating unit which the utility plans to build, absent a more economical or reliable alternative.

3. Require the utility to provide timely notice of its issuance of an RFP in major newspapers and publications with statewide and national circulation.

4. Require the utility to evaluate proposals (which may include non-utility generators, utility generators, turnkey offerings, and other generating supply alternatives) from which a manageable group of potentially viable and cost-effective finalists would be selected.

5. Require the utility to negotiate in good faith with the finalists to the solicitation process to achieve the most economical and reliable alternative to its next planned generating unit.

6. Limit the ability of non-participants to the RFP process to challenge the outcome of the selection process at a need determination proceeding. The selection process may be challenged at any time, either on the Commission's own motion or by a justified compliant by a substantially affected party.

7. Provide for a case-by-case waiver from issuing an RFP based on a Commission finding that such a waiver is in the best interests of the utility's ratepayers.

The FPSC did not adopt the staff's alternate rule which, had very detailed bidding criteria.

FPC generally supports the FPSC rule because it does not mandate bidding or require the selection of non-utility generators.

Florida Power believes generation resources should be managed using a "portfolio approach." Florida Power's current generation mix and diverse fuel sources are good examples of this principle.

Florida Power believes that if purchased power does not exceed a utility's reserve margin, the utility has the burden of proof to show why it did not select purchased power; however, once the reserve margin threshold is reached, then the utility should have to prove why purchased power is better than building new generation.

Florida Power proposed that the portfolio approach be used and that the burden of proof should change when the threshold is exceeded. Florida Power's position is based on the negative impacts that purchases have on utility cost of capital, planning flexibility, reliability and the obligation-to-serve.

Through its testimony, Florida Power stated that:

- High levels of purchased power contracts adversely affect a utility's credit quality.

- Evaluation criteria for purchased power contracts should be established to assign a level of equity to neutralize the off-balance sheet debt for the utility to maintain its capital structure. The additional cost of equity would then be imputed onto the bid.

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- Contracting for capacity does not result in all the benefits of ownership.

- The utility has an obligation-to-serve and an ensuing responsibility to plan, develop and manage its resources.

The Other Key Intervenors

- Florida Competitive Energy Producers Association (CEPA) - IPP trade association which includes Destec, Air Products, Cogentrix, Falcon Seaboard, Jay Makowski and Ark Energy.

- Legal Environmental Assistance Foundation (LEAF) - environmental conservation group

The Position of the IPPs

The IPP's expressed a need for a highly structured regulatory framework for the bidding process, including the selection criteria. This would put all parties on an equal basis by allowing all competitors access to the utility's optimization model and system operational data.

The IPP's felt that it would not be appropriate for the utility to control the bidding process. Currently, the utility, with no regulatory oversight or approval, determines the capacity need, drafts & publishes the RFP, receives and evaluates the bids, and selects the winner. Only at the end of the process is there FPSC involvement. They recommended that a neutral and unbiased party make the major decisions when the utility is a participant.

In addition, they want to establish procedures for utilities to automatically bid out all additional capacity needs once the Ten-Year Site Plan is filed.

The IPP's maintained that long-term purchase contracts do not effect the utility's cost of capital. In the absence of a disallowance, the buy option has no financial detriment on the purchasing utility when compared to building.

The IPP's stated that the buy versus build decision should be made in the broader context, that being whichever offers the ratepayer the best deal in terms of cost, risk and reliability.

Due to the passage of a competitive bidding rule, Florida Power is anticipating that the Power Plant Siting Act task force's expected recommendation for mandatory bidding will be ignored by the Florida State legislature next spring, since the FPSC will have already acted to resolve the perceived problems from the current need determination process. However, the proposed legislation from the PPSA task force would impose very stringent rules on utilities, greatly favoring conservation and IPP's.