FEATURES

CoalAge

Tax Credit Plants Emerge

Collecting a tax credit for producing a saleable product, Section 29 plants flourish.

By G. William Kalb

Editor's Note: Based upon the high attendance at various Section 29 presentations at Coal Prep '98 and '99 and an ongoing interest in the topic, the Advisory Board of Coal Prep 2000 has developed a half-day symposium specifically oriented to Section 29 projects. This symposium, scheduled for the Coal Prep 2000 morning session on Wednesday, May 3, in Lexington, Ky., is designed for both the exchange of information between Section 29 project participants and to provide a general background to the rest of the coal industry.

In sharp contrast to the consolidating coal industry and demise of the small operator, approximately 50 Section 29 projects have emerged during the past three years. The typical Section 29 project is designed to produce in the range of 300,000 to 500,000 tons per year (tpy) of a coal-based synthetic fuel, with the most viable operations using old slurry impoundments or fine product streams from existing preparation plants as a feedstock. Many in the industry have a concept of Section 29 projects but lack an in-depth understanding of them.

Section 29 projects came about as a result of the 1973 oil embargo by the Organization of Petroleum Exporting Countries (OPEC) and the subsequent quadrupling of the world price of oil. Congress enacted the IRS Code Section 29 Tax Credit Program in 1979 in an effort to decrease U.S. dependence on imported oil. The intent behind this tax credit program was to stimulate private investment in energy conservation, to promote energy produced from renewable resources, and to develop non-conventional energy sources. The tax credit was originally applied to a large number of fuels, including:

·Gas produced from coal seams and other non-conventional sources (landfills, etc);

·Oil from shale and tar sands;

·Steam produced from agricultural byproducts;

·Qualified, processed, wood-based fuels; and

·Liquid, gaseous, and solid coal-based synthetic fuels.

The tax credit was set in 1980 at $3 for the equivalent of each barrel of oil of a qualified fuel, with this value adjusted annually based on the inflation rate. A barrel of oil contains 5.8 million Btu, compared with a ton of a 12,000-Btu-per-lb coal containing 24 million Btu (equating to a $12.41-per-ton tax credit for each ton of synthetic coal-based fuel produced). Based on the inflation adjustment, the 1996 tax credit translated into $1.026 per million Btu (equating to a $24.62-per-ton tax credit for a 12,000-Btu-per-lb synthetic coal-based fuel). The tax credit is adjusted downwards as the price of oil increases, which, to this date, has had a very small impact on the tax credit. In 1998 the tax credit was $1.08 per million Btu which translates into a $25.92 tax credit for each ton of a 12,000-Btu-per-lb qualified synthetic coal-based fuel. The tax credit can be directly deducted, dollar for dollar, from the owners' tax bill.

A Section 29 qualified operation sells the synthetic fuel at the market price and simultaneously obtains the tax credit. In the case of a qualified synthetic coal-based fuel, the operator might sell a product for $22 per ton and then obtain a $25.92-per-ton tax credit (the tax credit is free, untaxable cash flow, assuming that the owner has the tax liability).

The program was initially utilized by the gas industry to develop gas reserves from non-conventional sources (coalbed methane, landfills, etc). It is estimated that $60 billion of investment was made in the recovery of coalbed methane, with gas production from alternative sources peaking between 1989 and 1994. Additional alternative gas production was from landfills, with this industry developed almost exclusively based on IRS Section 29. Within the gas industry, the Section 29 program resulted in significant progress being made in developing new technologies that would make the recovery of alternative sources of natural gas more economical. The Section 29 program was less visible in the oil industry because the large oil companies used the tax credits internally and Saudi Arabia had been flooding the market with oil with a lower price-per-million Btu than the cost-per-million Btu of producing oil in the United States from an alternative source (oil from shale and tar sands) minus the tax credit.

The coal industry's utilization of the Section 29 program matured slowly due to the requirement that synthetic fuel produced from coal must illustrate a chemical change, while the oil and gas industry had to produce their fuel from a less economic reserve. The first coal industry project that received a private letter ruling (the IRS' acceptance of the technology) was in 1986 for the K-Fuel process based in Gillette, Wyo. This process dried, decarboxylated, and stabilized a low-rank subbituminous coal and produced a 12,200-Btu-per-lb synthetic fuel usable in a boiler designed for bituminous coal without a derate.

Several amendments to the Section 29 IRS regulations did enhance the utilization of the coal industry's tax credit. First, the IRS program eventually was extended to include facilities that were online by June 30, 1998, with the tax credit applicable for 10 years following that date; and then a ruling by the IRS in the mid-1990s permitted the use of limited partnerships as a means of recruiting capital, decreasing the investment burden, and sharing (or selling) the tax credit.

These changes resulted in the development and commercialization of the Covol, Carbontite, Startec, Earthco, and E-Fuel processes that received favorable private letter rulings by the IRS.

Following a rush in late 1996 to sign engineering procurement contracts (a requirement for the tax credit), approximately 50 facilities claimed to be placed in service by the June 30, 1998, deadline. The major participants (multiple sites each) included Covol using a proprietary additive, Michigan Consolidated Gas using the Earthco process, Pace Carbon using the Covol process, Carbontronics using the Carbontite process, Startec using their own technology, and Duquesne Energy using the E-Fuel process (combine fine coal with waste paper and plastic byproducts).

Most of the above operations had the private letter ruling, the required engineering procurement, the construction contract, and had processed sufficient tonnage (frequently minimal) by June 30, 1998, to meet the IRS requirements. While there has been a significant falling-out of these operations, with approximately half of these original operations currently idle, it has been recognized that it is acceptable to modify various portions of the approved processes and/or to relocate these facilities. As a result, modifications are being made to the plants and a secondary market is developing for the relocation of those facilities that either were not economically viable or had a feedstock not amenable to the specific process.

With the exception of K-Fuels, Encoal, and Western Syncoal, most of the projects utilize a fine-coal feedstock (frequently from idle or active slurry impoundments) mixed with various additives and binders, followed by an agglomeration and drying process. A major positive result of the Section 29 projects has been the re-evaluation of various coal agglomeration systems including extrusion, pelletizing, and briquetting. Several of the ongoing modifications of the Section 29 approved facilities include the installation of alternative agglomeration processes (frequently briquetters replacing or augmenting pelletizing systems).

The re-evaluation of agglomerating systems for fine coal has major implications in the development of new clean coal technologies. Agglomeration of coal fines was a major U.S. business between 1900 and 1955 when stoker-sized coal was the dominant fuel for home heating/cooking, locomotives, and steam generating plants (for both power and industrial use). During this time period large amounts of otherwise nonusable fine coal (minus 1/4 inch) was binder briquetted as a stoker-sized fuel. However, the coal briquetting industry disappeared in North America with the advent of diesel locomotives, natural gas supply to homes, and pulverized fuel-fired power stations.

Today, with the current emphasis on environmental emissions, in conjunction with coal utilization and depletion of higher quality coal reserves, there is an increased need to deep clean coal (crush the preparation plant feedstock to a finer topsize to liberate more impurities). The deep cleaning approach requires the subsequent re-agglomeration of the beneficiated fine coal, with the Section 29 projects providing the commercial scale re-evaluation of these agglomeration processes. As a result of the Section 29 program, significant progress has been made in the development of lower-cost binder briquetting systems and binderless coal briquetting systems. The enhancement of these technologies significantly impact the future development of deep cleaning coal technologies and biomass type fuels.

The IRS program objective was to encourage the development of new technologies to economically recover alternative sources of fuel. The tax credits have a limited lifespan with the objective that the more viable sources of alternative fuels would eventually become economical without the tax credit.

Presently, the program for coal-based synthetic fuels remains very much alive and is in the process of recuperating, with facilities being relocated or modified to become commercially viable. It is anticipated that the tax credit program will be active through the 2008 deadline and various aspects/technologies developed for this program will eventually become economically viable without the supporting tax credit.

Kalb is president of Tra-Det Inc. located in Wheeling, W.Va. Contact at: 304/242-2092.

[illegible]

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 21-Apr-2000 08:43am
From: Mike Halpin TAL
HALPIN_M
Dept:
Tel No:

To: Walker, Jeff (Jeff.Walker@gen.pge.com)

Subject: Re: Cedar Bay Info Request

Jeff -
Good to hear from you. Coincidentally, I was planning to contact you about an issue that I am following which PG&E has some knowledge of in California. I'll ask my question after my responses to yours below:

Info request:

1. Can you direct me to a particular statute or guidance document that delineates what constitutes actual start-up parameters in boilers. Is there any specific mmBtu,opacity, CO2 level. etc. that when reached actually gives the boiler an on-line status. Cedar Bay's has several parameters incorporated into the CEM system that when reached, will designate that the boiler has formally transitioned from an off-line to a start-up/on-line status. I am not aware of the source of the start-up criteria and I would like a warm feeling that all is well here.

Since your question deals with CEMS, the direct answer to your question is that a boiler is "on-line" whenever it has heat input. See 40CFR75 SubPart B and I believe that 40CFR75.10(c) and (d) would provide the specific detail.

2. Corporate PG&E Gen is under the impression that a utility(either Florida Power or TECO) has proposed to do a test burn on a coal product that we have recently talked about, synfuel. Can you or are you able to validate if this is true and if you are able, can you advise me of the tentative date of the proposed test burn?

From what I have learned, FPC Crystal River has this approved in their permit. Apparently, they submitted an application and it was determined to not trigger PSD. I'm attaching 3 files for your use. Two of them deal with the PSD analysis and the 3rd is a copy of Crystal River's Title V permit. To my knowledge, a test burn was not completed.

3. Speaking of test burns, are test burn protocols that have been submitted to the DEP public record and if they are, what would be the most expeditious manner to obtain copies?

Any applications would be a matter of public record, but would require someone (from your office) to look through our files, as most of these documents are not electronically available. I do not believe that there are any standards regarding test protocols and am unaware of any recent test burns.
I believe that a few years ago, someone did a test burn for a blend of petcoke, and prior to that there was FPL's Orimulsion test. As you can

imagine, each case has its own issues, therefore I would advise:
1) If you decide you want to do a test, decide what you (PG&E) want to find out about it and come visit us (as in a meeting).
2) We'll suggest the things that we'll want, which will allow an application to be put together.

Alternately, you may be satisfied with what Crystal River has in their permit. In that case, you will need to show that PSD is not triggered and could try to get your Title V permit revised. If you wish to discuss this further, call me.

Now, here's my question - I am looking at a technology called SCONOx for a facility in Florida (operated by a competitor of yours). PG&E has incorporated this technology within an application at Otay Mesa (in California) and I've attached an article from the San Diego Union Tribune which notes this. I am trying to get my hands on (very quickly!) an estimate of the cost differential between SCR and SCONOx for a 175 MW (F frame) turbine. This is precisely what PG&E has applied for and thus my question - can you obtain this info for me?

Any info would be helpful.

Thanks
Mike

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. Applicant

Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33711

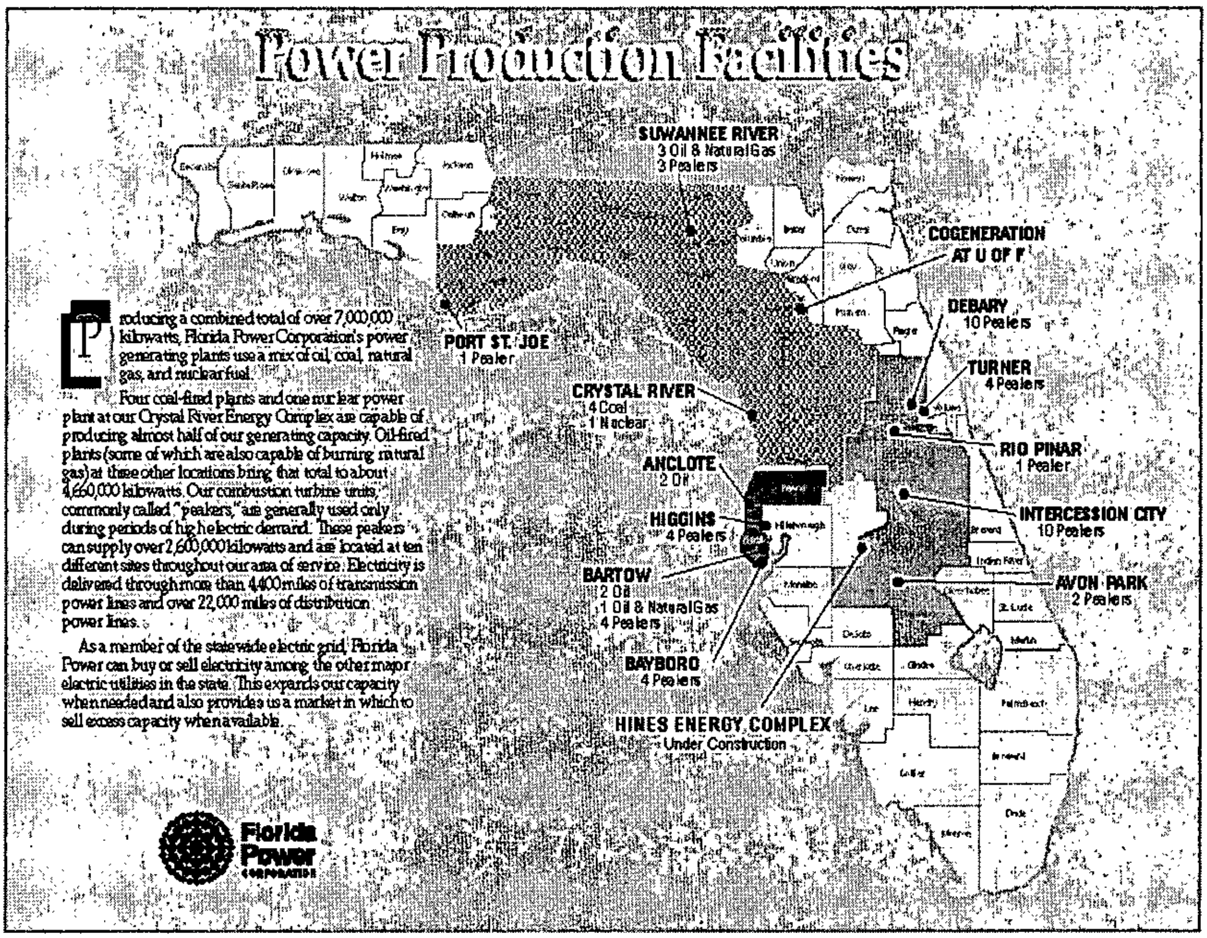
Authorized Representative: W. Jeffrey Pardue, CEP

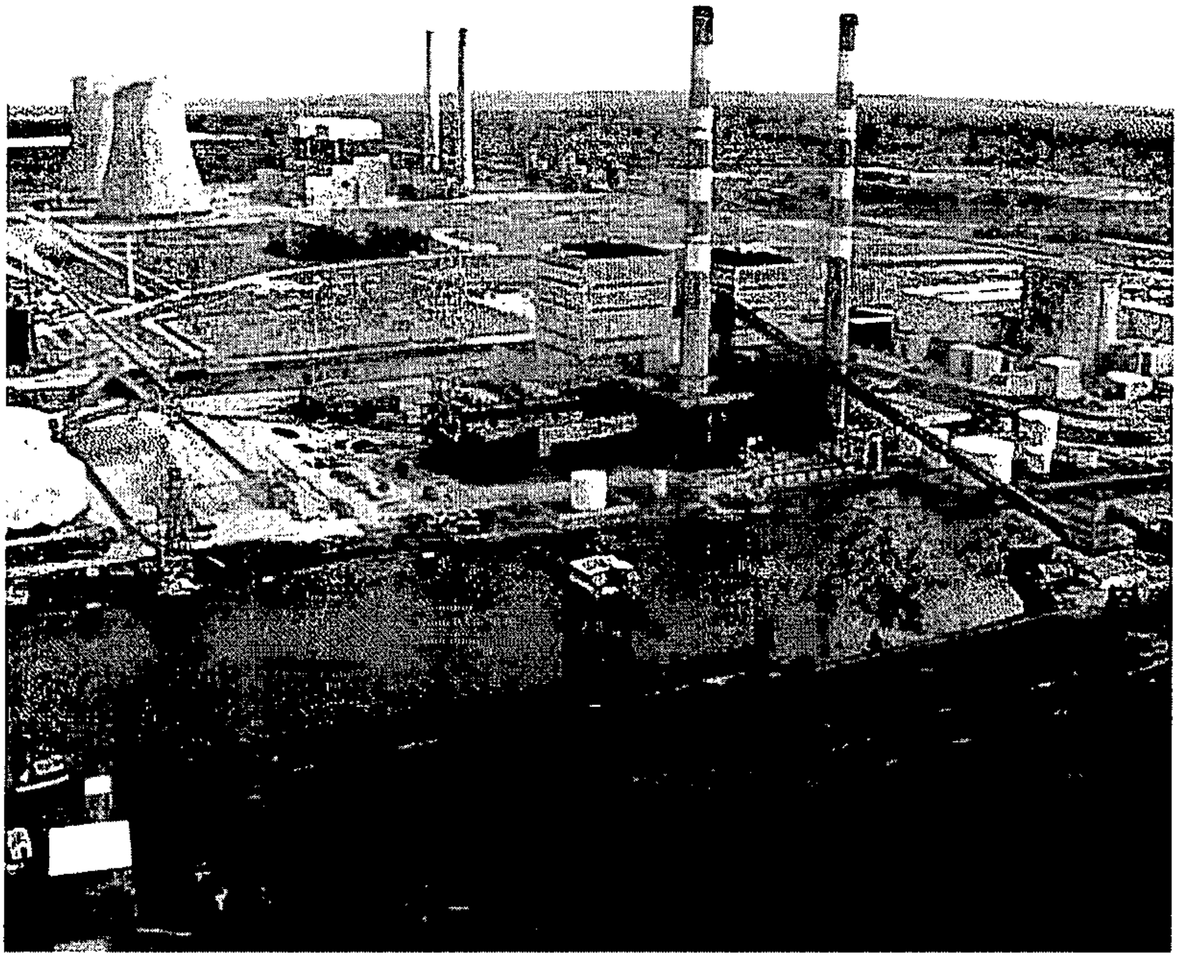
2. Source Name and Location

Crystal River Plant
Units 1, 2, 4, and 5
Crystal River, Citrus County

UTM Coordinates: Zone 17, 334.3 km East and 3204.5 km North. The plant is located on the Gulf of Mexico, approximately 7.5 miles Northwest of Crystal River, Citrus County.

The location of the Crystal River Plant within the FPC system is shown below followed by a photograph of the site downloaded from the FPC website.





Units 1 and 2 are in the foreground while Units 4 and 5 are in the background. The nuclear-powered:Unit 3 is to the right of Units 1 and 2.

3. Source Description

The Florida Power Corporation (FPC) Crystal River Plant consists of four steam electrical generating units. Units 1 and 2 are described in company information as coal units with net generating capacities of 373 and 469 megawatts respectively. Each unit has a 500 foot stack and employs saltwater cooling. Units 4 and 5 are also coal units with net generating capacities of 717 MW, 600 foot stacks, and 440 foot saltwater cooling towers.

4. Current Permit and Major Regulatory Program Status

Construction of Units 1 and 2 preceded most Federal and State clean air programs and began operation in 1966 and 1969 respectively. Construction of Units 4 and 5 was authorized by EPA Prevention of Significant Deterioration (PSD) Permit No. PSD-FL-007 and Florida Power Plant Site Certification PA77-09 and began operation in 1982 and 1984 respectively.

The four units are regulated under EPA's Title IV Acid Rain Program and are subject to the State of Florida's Major Source (Title V) Operation Permit requiements. An application for a facility-wide Title V operation permit was submitted by FPC in mid-1996. Conditions are still being negotiated between the Department and FPC.

5. Permit Modification Request

On February 24, 1998 the Department received a request from FPC for modification of its permits to add coal briquettes to the list of fuels authorized to be burned in Units 1, 2, 4, and 5. The briquettes will be produced from discarded coal fines from the mines that currently supply the coal for Units 1, 2, 4, and 5. Coal fines will be bound under heat and pressure with a small amount of Bunker C oil to produce briquettes that can be handled, combined, shipped and burned with the regular coal supply. Because the briquettes are produced from the same mines as the regular coal supplies, the chemical analyses of the briquettes and coal are similar.

Because the Bunker C oil used as a binder can actually have a higher sulfur content than the coal, even its less than one percent presence in the blended fuel could increase sulfur dioxide emissions from the plant by as much as 2,250 tons per year by Department estimates. Therefore FPC proposes to blend additional low sulfur coal into the regular coal supplies for the four units such that the average sulfur content will be maintained at the historical average from the past three years. FPC asserts and the Department accepts that burning briquettes will not cause measurable emissions increases and that a review for the Prevention of Significant Deterioration of Air quality (PSD) is not required.

6. Emissions Increases Due to Modification/Method of Operation

Because the main components of the units, including the compressors, combustors, rotors, fuel system, etc., will not be modified, it is arguable that the inlet foggers are not physical modification of the units. However the foggers are physical pieces of equipment whose addition and use can increase emissions on hot or dry days. The use of the foggers can also be considered a change in method of operation of the inlet "air conditioning system" that is already used to filter incoming air.

FPC estimated the maximum emissions increases by using the heat-input increase associated with a 20 degree F decrease in compressor inlet temperature. Using the heat input curve, a 20-degree F temperature decrease results in an increase in heat input of 60 mmBtu per hour. This value is multiplied by the emission rate in lb/mmBtu to obtain hourly emissions increases. The results are summarized below together with annual emission increase estimates, based on 1,750 hours of operation per fogger per year. The estimates are based on fuel oil firing and would be substantially less when firing natural gas.

TOTAL EMISSIONS INCREASES DUE TO USE OF INLET FOGGERS AT FOUR UNITS

Pollutant	Emission Rate lb/mmBtu	Emission Increase lb/hr	Annual Increase tons/yr	PSD Threshold tons/yr
NO_x	See Curve	11	39	40
PM/PM_{10}	0.015	0.9	3	25/15
CO	0.05	3	11	100
VOC	0.004	0.2	1	40
SO_2	0.19	11	40	40
SAM	0.016	1	3	7

The emissions increases calculated are the direct result from the modification or change in method of operation. These assume that the ability to achieve greater power output when the foggers are used does not result in the increased usage of the peaking units. The rationale is discussed below.

7. **Evaluation of PSD Applicability**

As a major source, a modification or change in method of operation of Units P7-P10 resulting in **significant net emissions increases** is subject to PSD review. Significant net emissions increase is defined in Rule 62-212.400, F.A.C as follows:

> *Significant Net Emissions Increase – A significant net emissions increase of a pollutant regulated under the Act is a **net emissions increase** equal to or greater than the applicable significant emission rate listed in Table 212.400-2, Regulated Air Pollutants – Significant Emission Rates.*

The significant emission rates are included (see PSD Threshold) in the Table above. The meaning of a net emissions increase is given in Rule 62-212.400, F.A.C. as:

> *Net Emissions Increase - A modification to a facility results in a net emissions increase when, for a pollutant regulated under the Act, the sum of all of the contemporaneous creditable increases and decreases in the **actual emissions** of the facility, including the increase in emissions of the modification itself and any increases and decreases in quantifiable fugitive emissions, is greater than zero.*

The definition of actual emissions is given in Rule 62-210.200, F.A.C. (definitions) as follows:

> *Actual Emissions - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:*
>
> *(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.*
>
> *(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.*
>
> *(c) For any emissions unit (other than an electric utility steam-generating unit specified in subparagraph (d) of this definition) which has not begun **normal operations** on a particular date, actual emissions shall equal the **potential emissions** of the emissions unit on that date.*

The term normal operations appears to be undefined and subject to some interpretation. Potential emissions are defined as follows:

> *Potential Emissions or Potential to Emit - The maximum capacity of an emission unit or facility to emit a pollutant under its physical and operational design. Any enforceable physical or operational limitation on the capacity of the emission unit or facility to emit a pollutant, including any air pollution control equipment and any restrictions on hours of operation or on the type or amount of material combusted, stored, or processed shall be treated as part of its design provided that, for any regulated air pollutant, such physical or operational limitation is federally enforceable.*

Actual hours of operation since the start of operations are as follows:

	Annual Operating Hours 1993 - 1998					
Unit/Year	1993	1994	1995	1996	1997	1998
P-7	193	873	649	1125	1996	1927
P-8	222	724	562	1269	1974	1796
P-9	68	697	715	1177	2031	1981
P-10	155	579	512	1186	1893	2015

There has been a steady increase in annual hours of operation since these units were installed in 1993. During 1997 and 1998, these units were each utilized between 1,796 and 2031 hours per year or more than half of the 3,390 permitted hours of operation per unit per year.

Although recent hours of operation are well below the permitted limits, they are actually fairly high compared with the typically low levels of operation characteristic of peaking units. Among the reasons for the relatively high levels are the prolonged shutdown of the baseloaded Crystal River Nuclear Unit 3 in 1997, the very hot summer of 1998, and the recognized low electrical power reserve margin in the State.

If these peaking units were being entirely replaced by larger units, it would be clear that they have not begun normal operations. In such a case, a comparison of future to past actual emissions would be based on a comparison of potential emissions to past actual emissions. Such a comparison would undoubtedly result in a determination that PSD is applicable unless the company took an extreme limitation in hours of operation.

If a like-kind replacement was being made, the same comparison would also result in a determination that PSD is applicable. That particular case was addressed for the purposes of comparison to the specific case addressed in the Puerto Rican Cement Decision. This is the watershed Federal Circuit Court of Appeals decision that upheld the past actual-to-potential emission comparison applicable to (at least) modernization projects. The comments of interest for the purposes of the present review are as follows:

> *"One can imagine circumstances that might test the reasonableness of EPA's regulation. An electricity company, for example, might wish to replace a peak load generator -- one that operates only a few days per year -- with a new peak load generator that the firm could, but almost certainly will not, operate every day. And, uncertainties about the precise shape of future electricity peak demand might make the firm hesitate to promise EPA it will never increase actual emissions (particularly since EPA insists, as a condition of accepting the promise and issuing the NAD, that the firm also promise not to apply for permission for an actual increase under the PSD review process). Whatever the arguments about the "irrationality" of EPA's interpretation in such circumstances, however, those circumstances are not present here. The Company is not interested in peak load capacity; it operated its old kilns at low levels in the past; its new, more efficient kiln might give it the economic ability to increase production; consequently, EPA could plausibly fear an increase in actual emissions were it to provide the NAD. Thus, this seems the very type of case for which the regulations quoted above were written. We can find nothing arbitrary or irrational about EPA applying those regulations to the Company's proposal."*

The FPC inlet fogger project is yet another step removed from a modernization project than the like-kind replacement example. The units will not be replaced at all. The modification and its effects can be isolated and directly estimated. The Department believes that the peaking units have begun normal operation. The addition of the inlet foggers will not change that fact or cause an increase in hours of operation. The modification itself (i.e. installation and operation of the foggers), however, has not yet begun normal operation and its future actual emissions based on potential to emit should be initially estimated assuming usage of the units at full capacity during the permitted 3,390 hours per unit per year.

The number of days during which the foggers can economically operate probably limits actual emissions increases to levels below significance for the purposes of PSD applicability. However, FPC proposes to limit operation of the foggers to 1,750 hours per unit per year. This value is approximately equal to the recent historical hours of operation for the four peaking units. It is also a clear indication that compressor air inlet cooling will not cause the units to operate all of the permitted hours. Emissions will increase under these limitations (as previously tabulated) by levels less than the significant emissions rates. The Department concludes, therefore that PSD does not apply to this project.

8. Proposed Addition of New Conditions to Permit PSD-FL-180

The construction permit has expired for the Intercession City Project to construct Units P7 through P11. The Department will re-issue the permit incorporating all other previously approved revisions and modifications to-date and will add a further condition authorizing installation and operation of the inlet foggers.

The new condition applicable to the inlet foggers proposed for Units P7 through P10 are shown in the draft re-issued and modified permit. It limits operation of the inlet foggers to 1,750 hours per unit per year.

9. Conclusions

The changes authorized by this permit modification will not cause increases in hours of operation and will not result in significant net emissions increases. The project will not increase the maximum short-term emission rates as these are already achieved under natural conditions of low ambient temperatures without the use of the foggers.

The Department concludes that PSD is not applicable to this project. The changes will not cause a significant impact or cause or contribute to a violation of any ambient air quality standard or PSD increment.

The Department's conclusion does not set a precedent for projects implemented at any facilities other than simple cycle peaking units. It does not set precedents related to any physical changes within the compressors, combustors, rotors, or other key components at such units. The application and determination of the Department's rules does not constitute an interpretation of the EPA rules under 40CFR52.21, Prevention of Significant Deterioration or 40CFR60, New Source Performance Standards.

PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATIONS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File Nos. 01740004-005-AC, PSD-FL-007

Florida Power Corporation Crystal River Plant
Units 1, 2, 4, 5 Coal Briquettes Project
Citrus County

The Department of Environmental Protection (Department) gives notice of its intent to issue Permit Modifications to Florida Power Corporation (FPC). The permit is to burn a maximum 20 percent blend of coal fines briquettes with coal by weight at the Crystal River Plant in Citrus County. A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. or 40 CFR52.21. The applicant's name and address are Florida Power Corporation, Post Office Box 14042, MAC BB1A, St. Petersburg, Florida 33733.

The briquettes will be produced from discarded coal fines from the mines that currently supply the coal for Units 1, 2, 4, and 5. Coal fines will be bound under heat and pressure with a small amount of Bunker C oil to produce briquettes that can be handled, combined, shipped and burned with the regular coal supply. Because the briquettes are produced from the same mines as the regular coal supplies, the chemical analyses of the briquettes and coal are similar.

Because the Bunker C oil used as a binder can actually have a higher sulfur content than the coal, even its less than one percent presence in the blended fuel could increase sulfur dioxide emissions from the plant by as much as 2,250 tons per year by Department estimates. Therefore FPC proposes to blend additional low sulfur coal into the regular coal supplies for the four units such that the average sulfur content will be maintained at the historical average from the past three years. FPC asserts and the Department accepts that burning briquettes will not cause measurable emissions increases and that a review for the Prevention of Significant Deterioration of Air quality (PSD) is not required.

An air quality impact analysis was not required or conducted. No significant impacts are expected to occur as a result of this project. It will not cause or contribute to a violation of any ambient air quality standard or increment.

The Department will issue the FINAL Permit Modifications with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Permit Modifications." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
3319 Maguire Boulevard, Suite 232
Tampa, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-5963

The complete project file includes the application, technical evaluation, Draft Permit Modifications, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.