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September 15, 1994

VIA HAND DELIVERY

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
101 E. Gaines Street
Tallahassee, Florida 32301

Re: Amendment to Standard Offer Contracts of Florida Power Corporation and Auburndale Power Partners, Limited Partnership, Docket No. 940819-EQ

ACK ✓ AFA APP CAF CMU CTR EAG LEG LIN 6 OPC RCH SEC 1 WAS OTH

Brown

Dear Ms. Bayo:

We write on behalf of our client Auburndale Power Partners, Limited Partnership ("APP") to object to staff's recommendation dated September 8, 1994 in this docket. The matter is listed as Item No. 9 on the September 20, 1994 Agenda. APP recognizes that written responses to recommendations are not common. However, because the Commission's vote on this matter will affect the entire projects of both APP and LFC No. 47 Corp. ("LFC"), we believe that it is important to clearly frame APP's positions now to promote orderly discussion at the September 20 Agenda Conference and avoid unnecessary formal hearings. APP's positions on each of the issues identified in staff's recommendation are set forth in Appendix A.

Summary of Position

This transaction involves the proposed assignment of two standard offer contracts currently owned by LFC to APP. Florida Power Corporation ("FPC") has consented to the assignment. As part of the assignment, the parties have agreed that the standard offer contracts will be performed from APP's cogeneration facility located south of FPC's Central Florida Substation near Auburndale, Florida and that output under the contracts will be curtailed during times that FPC's loads are low. APP and FPC believe that the contemplated assignment, the change in location, and the agreed upon curtailment associated with the standard offer contracts do not, and should not, alter the Commission's prior approval of cost recovery under the contracts. Should, however, the Commission determine that the contract modifications require further cost recovery review, there are demonstrable ratepayer benefits to support cost recovery approval. FPC has provided the Commission with data demonstrating that the transaction will save its ratepayers in excess of $46 million over the life of the transaction and will alleviate Commission recognized transmission capacity constraints by relocating the situs of the contracts south of FPC's Central Florida Substation.

Staff states that while there may be public benefits from the transaction, those benefits have not been "sufficiently demonstrated" to warrant Commission approval. APP believes that the benefits and ratepayer savings are real and respectfully objects to Staff's recommendation. APP urges the Commission to approve the joint petition at the September 20 Agenda Conference.

Background

The issues involving the assignment of the standard offer contracts were initially presented to staff in November and December of 1993. The transaction was formally filed with the Commission almost 5 months ago as a joint petition for declaratory statement. On July 7, 1994, staff issued a recommendation addressing the declaratory statement request stating that the assignment constituted a new contract by novation and suggested that the parties seek approval of the "new" contract pursuant to the Commission's proposed agency action procedures. Although APP denied, and continues to deny, that the contemplated assignment ever constituted a novation, it renegotiated the transaction to address staff's concern and advised staff counsel that it intended to file an amended petition for declaratory statement. On July 29, 1994 APP, FPC, and LFC met with the Commission's General Counsel, the Director of the Electric and Gas Division, and other members of technical and legal staff to address the assignment and obtain staff guidance as to its recommended procedure for timely processing the matter. At that time, APP, FPC and LFC advised staff of the time-critical nature of the proceeding and that the parties were operating under a deadline of August 31, 1994, beyond which any party could terminate the agreement at will. Staff recommended that the parties seek Commission approval of contract modifications under the Commission's proposed agency action procedures. Staff also orally identified a list of information that it would need to process the request, and stated that it would work to process the petition in time for consideration at the September 20 Agenda Conference. Finally, staff specifically agreed that if it had questions regarding any supporting data or needed additional information it would so advise the parties to avoid unnecessary delay.

On August 5, 1994, the parties withdrew the petition for declaratory statement and contemporaneously refiled a petition for approval of contract modifications in accordance with the procedures recommended by staff. On August 22, 1994 FPC submitted the data that staff requested regarding the benefits and impacts of the assignment transaction. Prior to filing its recommendation on September 8, 1994, staff never once questioned the supporting data or requested additional information despite repeated phone calls by APP to staff inquiring as to whether staff had questions, concerns, or needed additional information concerning the filings. Until receipt and review of staff's September 8 recommendation, APP firmly believed that ample evidence had been timely filed to support the approval of the contract modifications. Staff's critique of the data supporting the joint petition places the parties in the difficult position of having to respond to recently stated staff concerns at Agenda Conference.

Specific Response to the Staff Recommendation

If adopted, staff's recommendation would appear to set new industry-wide policy regarding standard offer contracts. Staff states that once a standard offer contract is approved by the Commission for cost recovery purposes, any change in the situs of the contract or fuel type of the generating facility supplying power under the contract would invalidate the Commission's prior cost recovery approval and require new review. Recommendation at 4. This standard has never before been articulated by the Commission. In fact, when the Commission initially approved FPC's form standard offer contract to which LFC is a party, it never addressed the location of the QFs that would eventually execute FPC's standard offer. Indeed, the location provision was left blank.[1] Additionally, the fuel type of the generating facility is never mentioned in FPC's standard offer contract and was never a factor considered by the Commission when it approved the LFC standard offer contracts for cost recovery. Furthermore, there is nothing in the LFC Standard Offer Contracts that prohibits LFC from changing the fuel type of its facilities during the term of the contracts. It is simply wrong for staff to now suggest that mutually agreed on and beneficial changes involving contract location and fuel type will somehow invalidate prior determinations of cost recovery under the standard offer contracts. Staff's

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[1] In re: Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Prices for Peninsular Florida's Electric Utilities, 88 F.P.S.C. 1:435, Docket No. 880004-EQ, Order No. 18735 (January 26, 1988).

position also directly contradicts established Commission policy not to revisit standard offer contracts once approved.[2] In addition, if the Commission implements this new policy in this proceeding it will be effectively applying new Commission rules in midstream.

Florida's Administrative Procedures Act provides that an agency must adopt rules through the appropriate rulemaking procedures unless rulemaking is not feasible and practicable.[3] Thus, if the Commission seeks to adopt cogeneration policy regarding assignment, changes in location, and changes in fuel type associated with standard offer contracts it must do so through rulemaking unless it can show that rulemaking is impracticable. There are no indications of any impediments to rulemaking in this case. In fact, the Commission staff has admitted that rulemaking regarding these issues is available because assignment of standard offer contracts, change in location, and change in fuel type are matters currently being debated in an ongoing rulemaking proceeding. See page 4 of Staff Recommendation dated August 25, 1994, in Docket No. 931186-EQ, listed as Item 2 on the September 20 Agenda. If new policy is adopted, it should be done through the appropriate procedures and should be applied on a prospective basis so not to unfairly jeopardize existing projects and contracts. This is consistent with the Commission's policy not to apply its cogeneration rules and changes to those rules retroactively.[4]

Should the Commission determine that the contemplated modifications to the standard offer contracts now require further approval for purposes of cost recovery, there are demonstrable ratepayer benefits to support such cost recovery approval. On August 12, 1994, FPC submitted a package of data supporting the joint petition and responding to staff's inquiries at the July 29 meeting. See FPC Responses to Staff Questions dated August 22, 1994, attached hereto as Appendix B. In response to Staff Question No. 7, FPC has performed a revenue requirements analysis which

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[2] Florida Power & Light v. Beard, 626 So.2d 660 (Fla. 1993); In re: Planning Hearings on Load Forecasts Generation Expansion Plans, and Cogeneration Prices for Florida's Electric Utilities, 91 F.P.S.C. 8:560, 629, Docket No. 910004-EQ, Order No. 24989 (August 19, 1991).

[3] Fla. Stat. §120.535 (1993).

[4] In Re: CFR BIO-GEN's Petition for a Declaratory Statement regarding the Methodology to be used in its Standard Offer Cogeneration Contracts with Florida Power Corporation, 91 F.P.S.C. 4:109, 114, Docket No. 900877-EI, Order No. 24338 (April 9, 1991).

shows that over the life of the transaction there are ratepayer savings in excess of $46 million to be derived from the agreed on curtailment modifications, the net present value of which exceeds $12.8 million. See Appendix B, pages 3 and 17.

FPC and APP have also advised the Commission of the transmission and reliability benefits of relocating the situs of the standard offer contracts to Polk County, south of FPC's Central Florida Substation. Joint Petition at 12. Contract location south of that substation enhances FPC's ability to import bargain and emergency power during times of need. These benefits are real and have been recognized as such by the Commission. The Commission has formally determined that projects located north of the Central Florida Substation aggravate FPC's north-to-south transmission capacity constraint problem and impede FPC's ability to import bargain and/or emergency power from the Georgia System.[5] In addition, the Commission has specifically approved FPC's cogeneration policy that penalizes the location of projects north of the Central Florida Substation because it "ensures that the ratepayers do not pay for transmission capacity that they would not have purchased, had FPC constructed its avoided unit in Polk or Hardee County."[6]

Staff states on page 8 of its recommendation that while benefits may be derived from the contract modifications, they have not been "sufficiently demonstrated" to warrant Commission approval. Staff's characterization of the joint petition and supporting data as "insufficient" plainly contradicts the Commission's past treatment of other cogeneration contract modifications. This inconsistency is illustrated by review of at least two prior Commission orders: Order No. PSC-92-0129-FOF-EQ in Docket No. 900383-EQ; and Order No. 17615 in Docket No. 861367-EI.

1. CFR-Biogen - Order PSC-92-0129-FOF-EQ.

In the CFR-Biogen matter, CFR-Biogen and FPC were involved in a dispute regarding certain terms of two standard offer contracts.[7]

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[5] In Re: Planning Hearings on Load Forecasts Generation Expansion Plans, and Cogeneration Prices for Florida's Electric Utilities, 91 F.P.S.C. 8:560, 578-9, Docket No. 910004-EU, Order No. 24989.

[6] Id. at 580.

[7] In re: Complaint by CFR-Biogen Corporation Against Florida Power Corporation for Alleged Violation of Standard Offer Contract, and Request for Determination of Substantial Interests., 92 F.P.S.C. 3:657, Docket No. 900383-EQ, Order No. PSC-92-0129-FOF-EQ

The parties eventually resolved the dispute by negotiating a new power sales agreement. CFR-Biogen and FPC filed a joint petition for approval of the negotiated contract with the Commission. In determining whether to approve the negotiated contract, the FPSC compared the benefits of the original standard offer contracts to the benefits of the negotiated contract. The CFR-Biogen staff recommendation states:

> CFR has signed two previous standard offer contracts with FPC in 1987 and 1988. For all practical purposes, the single negotiated contract presently before the Commission is a modification of those existing contracts. That being the case, the only relevant analysis is to compare the two payment streams of the contracts. (Emphasis supplied.)

The Commission approved the negotiated contract executed by CFR-Biogen and FPC stating that it "is more cost-effective than the parties' standard offer agreements."[8] The Commission also noted that "it appears that the negotiated contract will yield a savings of approximately 7 million over the life of the contract."[9] FPC's projected estimated savings resulting from the assignment of the LFC Standard Offer Contracts to APP is $46,550,480 over the life of the contract which is more than 6 times the savings on which the Commission based its approval of the CFR-Biogen negotiated contract.

2. Conserv -- Order No. 17615.

In the Conserv matter, Conserv and Tampa Electric Company ("TECO") were involved in litigation before both the Commission and the circuit court regarding the terms of a cogeneration agreement that they executed in 1981.[10] Following a partial summary judgement issued by the circuit court holding that Conserv had the right to renegotiate the agreement, Conserv and TECO renegotiated and executed a new cogeneration agreement. The Commission found

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(March 31, 1992).

[8] Id. at 658.

[9] Id. (emphasis supplied.)

[10] In re: Petition of Tampa Electric Company for Approval of Payments to Conserv, Inc. Pursuant to Amended Cogeneration Agreement., 87 F.P.S.C. 5:322, Docket No. 861367-EI, Order No. 17615 (May 26, 1987).

that the renegotiated agreement was a new contract.[11] In determining whether to approve the renegotiated contract, the Commission compared revenue flows under the original and renegotiated contracts.[12] The Commission stated that "staff's analysis shows that changing the billing methodology, and other minor changes results in a range of potential <u>annual revenue losses</u> of $14,259 to $107,064 for the remaining years of the contract."[13] The Commission further stated that "[t]he net present value of the total potential losses is $447,614."[14] Although supporting data indicated a negative ratepayer impact, the Commission justified its approval of the renegotiated contract by finding that <u>if</u> Conserv experiences unplanned outages or buys back-up power that exceeds 5% of its load, the renegotiated contract could be beneficial to the ratepayers.[15] The Commission approved the renegotiated contract stating that "it appears likely that the renegotiated contract will ultimately save the ratepayers a modest sum as it will cost them a modest sum."[16] Thus, in Conserv, the FPSC approved a new contract when its benefit to the ratepayers was speculative, and if realized, any savings would be modest. In contrast, FPC has represented that the assignment of the LFC Standard Offer Contracts to APP will result in a definite benefit to FPC's ratepayers of approximately $46 million over the life of the contract, which savings will be realized immediately.

Staff also appears to have overlooked the data filed by FPC in support of the joint petition. For example, staff seems to suggest that FPC "did not respond" to staff's inquiry why FPC elected to negotiate curtailment as part of mutually agreed upon "contract modifications" instead of attempting to unilaterally curtail without the QF's consent. Recommendation at 5. FPC specifically responded to this inquiry in its Response to Staff's Questions dated August 22, 1994:

> FPC has negotiated these curtailment agreements in an effort to mitigate the anticipated minimum load problem. FPC felt it appropriate to negotiate with the QFs directly

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[11] <u>Id.</u> at 323.

[12] <u>Id.</u>

[13] <u>Id.</u> (emphasis supplied.)

[14] <u>Id.</u>

[15] <u>Id.</u>

[16] <u>Id.</u> at 324.

> because past experience has shown that the FPSC would prefer affected parties negotiate a settlement whenever possible.

FPC Response to Staff Question No. 2. FPC's response to the inquiry was clear: FPC chose to negotiate a curtailment agreement with the QF that has significant benefits to the ratepayers rather than attempting to unilaterally curtail through litigation.

Staff's reluctance to recommend approval appears to be based on the rationale that "it would not be good public policy to allow an existing renewable resource facility to be abandoned in order to generate power from a natural gas facility, unless there are substantial benefits to FPC's ratepayers." Recommendation at 4. There is no basis for staff to suggest that there is an established Commission policy which would prohibit the owner of a renewable resource facility from ceasing operation of that facility. Indeed, as of the date of this letter, the Commission is currently debating whether to initiate a rulemaking proceeding to consider adopting formal policy with respect to renewable generators in Docket No. 931186-EQ which is pending as Item No. 2 on the September 20 Agenda. As previously discussed in this letter, to retroactively apply staff's policy when the underlying premise to that "policy" is subject to debate in a pending rulemaking docket is inappropriate according to established Commission policy and the Administrative Procedures Act.

In addition, staff makes several flawed assumptions for applying its purported "policy" regarding renewable resources to this assignment transaction. First, staff erroneously states that LFC intends to abandon the facilities after the assignment. LFC has never expressed that intent, rather it has simply stated that it will not sell energy and capacity to FPC under the LFC standard offer contracts. Second, staff erroneously assumes that the LFC plants are renewable resource facilities. In fact, the LFC standard offer contracts were approved by the Commission for cost recovery purposes without any regard to fuel type and there is absolutely no obligation on the part of LFC to utilize renewable fuel. This problem of determining what is and what is not a renewable resource facility stems from the absence of statutory or regulatory authority defining renewable resource generators. Indeed, staff in its recommendation that the Commission adopt new rules regarding renewable resource generators recognizes that a "controversial issue will be the definition of ... renewable resource." See page 6 of Staff Recommendation dated August 25, 1994 in Docket No. 931186-EQ. Third, staff mistakenly suggests that the substantive terms of the LFC contracts have fully commenced. In fact no capacity payments have been made under the LFC standard offer contracts, and the assignment is scheduled to occur prior to FPC paying for any capacity.

Requested Commission Action

APP seeks only fair and consistent regulatory treatment and in that regard respectfully requests the Commission to apply the same standards to this case that it has in other cases involving assignments and cogeneration contract modifications. To the extent that the Commission determines that the contract modifications require further cost recovery review, the Commission should find that the benefits of the transaction derived from the agreed upon curtailment and contract relocation are clearly sufficient to justify the approval of the joint petition at the September 20 Agenda. The $46 million in ratepayer savings resulting from curtailment is based on the same revenue requirement analysis upon which the Commission has relied in the past to evaluate cogeneration contract modifications. Additionally, the transmission benefits of administering the contracts from Polk County has been specifically acknowledged in prior Commission orders. Moreover, the benefits and savings projected from this transaction far exceed projected savings in other proceedings where the Commission has approved contract modifications.

For these reasons we respectfully request that you deny staff's recommendation and approve the joint petition. We will be in attendance at the September 20, 1994 Agenda Conference to address the matter further. Thank you for your consideration.

Sincerely,

HOLLAND & KNIGHT

D Bruce May

D. Bruce May

cc: Chairman Deason
Commissioner Johnson
Commissioner Clark
Commissioner Garcia
Commissioner Kiesling
Martha Brown
Tom Ballinger
Joe Jenkins
Rob Vandiver

Enclosure
DBM/sms

TAL-49824.4

APP's PROPOSED RECOMMENDATION

ISSUE 1: Is LFC's assignment of its Standard Offer Contracts with Florida Power Corporation to Auburndale Power Partners contemplated by the terms of those contracts?

RECOMMENDATION: Yes. Section 9.6 of the original Standard Offer Contracts permits assignment with FPC's prior written approval.

ISSUE 2: Is the change in location from the existing LFC facilities in Madison and Jefferson counties to the Auburndale facility in Polk County, Florida, contemplated pursuant to the original Standard Offer Contracts?

RECOMMENDATION: Yes. The original Standard Offer Contracts were approved for purposes of cost recovery without regard to location of facilities or fuel type and there is nothing in the contracts to prevent the QF from changing the location or fuel type of the facilities over the life of the contracts. In re: Annual hearings on load forecasts, generation expansion plans and cogeneration prices for Peninsular Florida's electric utilities, 88 F.P.S.C. 1:435, Docket No. 880004-EQ, Order No. 18735 (January 26, 1988). Thus, the contemplated changes in the situs of the contracts and the fuel type of the generating units should not affect the Commission's prior determination of cost recovery. Additionally, the utility is supportive of the location change and the Commission has recognized significant ratepayer benefits from administering contracts such as these south of FPC's Central Florida Substation. See In re: Planning Hearings on Load Forecasts Generation Expansion Plans, and Cogeneration Prices for Florida's Electric Utilities, 91 F.P.S.C. 8:560, 578-80, Docket No. 910004-EQ, Order No. 24989 (August 29, 1991).

ISSUE 3: Are the agreed upon "Off-Peak Curtailment Periods" as defined in the Consent and Agreement between Auburndale, FPC, and LFC contemplated pursuant to Sections 5(a) and 5(c) of LFC's original Standard Offer Contract?

RECOMMENDATION: Yes. The mutually agreed upon "Off-Peak Curtailment Periods" are contemplated by Sections 5(a) and 5(c) of the original Standard Offers. Furthermore, there are demonstrable benefits from such mutually agreed curtailment in that it coordinates output under earlier vintage contracts with FPC's present load requirements and creates ratepayer savings by avoiding purchases of unneeded power. These benefits justify Commission confirmation that the contracts as modified continue to qualify for cost recovery.

ISSUE 4: Should the joint petition for approval of contract modifications be approved?

RECOMMENDATION: Yes. The Consent and Agreement has not materially altered the original Standard Offer Contracts so as to necessitate additional approval of cost recovery. However, should the Commission determine that changes in contract location, facility fuel type and the agreed upon curtailment require additional review, that review should consist of an evaluation of benefits to FPC's ratepayers. There are demonstrable ratepayer benefits (including, without limitation, ratepayer savings in excess of $46 million) to support approval of cost recovery under the contracts as modified. The benefits of the modified Standard Offer Contracts exceed the benefits on which the Commission has previously based its approval of other cogeneration contract modifications. See Order No. PSC-92-0129-FOF-EQ and Order No. 17615.

ISSUE 5: If the assignment and change in location are approved, would Rule 25-17.0832(3)(a), Florida Administrative Code be violated?

RECOMMENDATION: No. If the assignment and change in location are approved as being contemplated pursuant to the original LFC Standard Offer Contracts or as part of a new negotiated contract, then Rule 25-17.0832(3)(a), Florida Administrative Code, would not apply.

TAL-49988

FPC Response To FPSC Staff Questions Concerning LFC Assignment

Q1. Quantify under a net benefit analysis the amount and costs of economy power that could not be imported if LFC operates its two cogeneration facilities in Jefferson and Madison Counties?

A1. FPC's import limit is presently 456 MW and will reduce to 438 MW by 6/1/95. FPC presently has firm contracts that utilize this import totalling 416 MW. By moving LFC to Auburndale, FPC's "theoretical" import limit would increase by 17 MW. In order to determine the exact number, FCG studies would need to be run and the exact value agreed on by affected parties. This benefit is difficult to quantify at this time, however perceived benefits in the future could be:

- During capacity shortage conditions, additional emergency power could be purchased.
- Economy power could be purchased that could lower FPC's generation costs at certain times.

Q2. Assuming that the LFC Projects are performed at the Jefferson and Madison County locations in accordance with the requirements of the original Standard Offer Contracts, including the 70% capacity factor, would FPC be confronted with a minimum load problem? If so, would it be administratively expedient for FPC to attempt to resolve that problem by evoking the curtailment provisions of Rule 25-17.086?

A2. FPC anticipates a minimum load problem at certain times even with the curtailments that have been negotiated to date (including LFC curtailments at Auburndale). Without LFC curtailing its 17 MW off-peak, the conditions worsen. FPC is presently developing curtailment plans for various low load scenarios. Once these plans are complete they will be reviewed with FPSC and the QFs.

FPC has negotiated these curtailment agreements in an effort to mitigate the anticipated minimum load problem. FPC felt it appropriate to negotiate with the QFs directly because past experience has shown that the FPSC would prefer the affected parties negotiate a settlement whenever possible.

Q3. Assuming that LFC does not perform at the 70% capacity factor, what are the default provisions under the current Standard Offer Contracts?

A3. The LFC contracts will default under the following conditions:

- After January 1, 1995, LFC fails to maintain an overall capacity factor of 70% based on a twelve month rolling average basis for 24 consecutive months.

- After January 1, 1995, LFC refuses or is unable to deliver the Committed Capacity of 17 MW.

- LFC ceases all electric generation for 12 consecutive months.

- LFC voluntarily declares bankruptcy.

Once LFC is declared in default, FPC's obligation to make capacity payments is suspended until the default is remedied.

Q4. Quantify LFC's costs of retrofitting its plant so as to meet the performance criteria under the Standard Offer Contracts.

A4. See attachment 1 that was supplied by LFC (FPSC supplied original via separate submittal).

Q5. Can the LFC Standard Offer Contracts be compared with FPC's current avoided unit.

A5. Attachment 2 compares the net present value (NPV) of the existing LFC contracts (Big Ben4) and FPC's current avoided unit (advanced combustion turbine). There is an NPV difference of over $20 million (includes capacity and energy), with the combustion turbine the cheaper alternative.

Q6. What specific benefits will flow to FPC from the curtailment contemplated in the Standard Offer Contracts under the Assignment?

A6. By assigning the LFC contracts to Auburndale, FPC is able to negotiate voluntary curtailments for both the LFC and Auburndale (ElDorado) contracts. This allows up to 31.2 megawatts to be curtailed off-peak which is not likely without the LFC assignment. FPC has been actively negotiating voluntary curtailments with all QFs in an attempt to alleviate any possible low load problems (See Question 2 also).

The voluntary curtailments at the Auburndale facility will reduce the frequency and associated costs of:

- o Cycling FPC coal units.
- o Start-up and shut-down of FPC coal units.
- o Supplementary firing with No. 2 oil or gas of FPC coal units.
- o Possible uneconomic generation operation of the FPC system (i.e. use of combustion turbines to meet the shoulder hour demand).

Q7. Staff requested Present Value Revenue Requirement ("PVRR") analysis under three scenarios:

a. FPC's PVRR assuming that the 114 MW Auburndale negotiated contract is performed with no curtailment and the remaining 36 MW is sold on an as-available basis to FPC, plus FPC's PVRR under the original LFC Contracts performed from the Madison and Jefferson locations.

b. FPC's PVRR assuming that the Auburndale 114 MW negotiated contract is operated with curtailment with the LFC plants operating under the Standard Offer Contracts in north Florida.

c. FPC's PVRR if the Assignment is approved and the existing 114 MW negotiated contract is operated with the curtailment, and the LFC contracts are moved to APP location in Auburndale and operated under the curtailment contemplated in the Assignment.

A7. Attachment 3 compares FPC production costing runs and projections for Scenarios 1 and 3 for the 30 year term of the LFC contracts. There is an estimated cumulative net present value (NPV) savings of $12,818,623 on assigning LFC contracts to Auburndale. This savings is based on FPC's current cost of money (8.95%). Savings are due to better on-peak performance (Auburndale has a required 92% on-peak capacity factor performance) and the negotiated 100% curtailment of the LFC 17 mw capacity off-peak.

Scenario 2, where Auburndale agrees to curtailment off-peak without assignment of the LFC contracts, does not appear practical. Auburndale has no incentive to a voluntary curtailment agreement because the facilities' generating capacity (150 MW) is far in excess of the present firm contract capacity (114.18 MW).

Q8. Staff inquired as to what was to be done with respect to the interconnect.

A8. On approval of the assignment of the LFC contracts to Auburndale, the FPC and LFC existing transmission interconnection agreements will terminate. The existing transmission connections at LFC (Jefferson and Madison County) will be electrically isolated from the FPC system. Any continuing power requirements at these facilities will be supplied via local 13 KV distribution. As far as the removal of existing transmission facilities (estimated removal cost - $20,000 per connection), this is dependent on LFC negotiating new power sales contracts and new transmission interconnection agreements with FPC. It should be noted that any new transmission interconnection agreements would require up-grade of the existing transmission interconnections (addition of telemetering and automatic sectionalization).

Florida Power Corporation
Cogeneration Contracts and
Administration Department
8/19/94

ATTACHMENT 1

August 11, 1994

FPSC
Florida

RE LFC No.47 Corp., Madison and Jefferson Plants

Dear

LFC No.47 Corp. ("LFC 47") is a single purpose corporation having as its sole assets all of the equipment, real estate, permits, contracts, etc. required to operate two power plants. One of the plants is located in Madison County, the other is in Jefferson County, Florida. Both plants have standard approved 8.5 MW contracts ("PPA") to sell energy to Florida Power Corporation ("FPC"). Under these contracts, the plants must pass a Capacity Test before January 1, 1995, and continue to deliver energy at a 70% Capacity Factor after December 31, 1994. Both Capacity Test and Capacity Factor are defined in the PPAs.

Questions have been raised regarding the viability of the above referenced plants and whether the approval of a contemplated assignment of PPAs would be a "lifeline" to plants that are otherwise not viable. The purpose of this letter and attachments is to present information showing that the plants are viable and can meet the Capacity Test and Capacity Factor.

FINANCIAL BACKING OF LFC 47

LFC 47 is a subsidiary of LFC Energy Corporation ("LFC Energy"), which is a subsidiary of LFC Financial Corp ("LFC Financial"). LFC Financial is a closely held diversified corporation having its origin as Lease Financing Corporation, founded in 1963. As a part of this diversity, LFC Financial has invested in a number of energy projects through LFC Energy. As of December 31,1993, LFC Energy had total assets of $129,729,592 and LFC Financial had total assets of $376,934,000.

OTHER LFC ENERGY PROJECTS

In addition to the Madison and Jefferson plants in LFC 47, LFC Energy, through other special purpose subsidiaries, owns two 50 MW and one 25 MW gas fired plants in California, a 20 MW wood chip fired plant in Michigan, a 22 MW windfarm in California, and substantial gas interests in California, Colorado, and Texas. LFC Power Systems Corporation ("LFC Power") is another subsidiary of LFC Energy with approximately 200 employees who provide all design, engineering, permitting, operating and maintenance personnel to all LFC Energy projects as well as to outside third parties under negotiated contracts. Because of good operating and maintenance practices on the part of LFC Power, the gas plants and the windfarm consistently run with an availability factor exceeding 97%, and the wood plant runs at about a 93% availability factor. The 70% Capacity Factor in the Madison and Jefferson PPAs should be easily achieved. (See additional information regarding the Capacity

Factor presented in Attachment 1, Madison And Jefferson Plants - Availability Analysis.) The three California gas plants and the Michigan wood plant were designed and built by LFC Power.

LFC 47 HISTORY

The Madison and Jefferson plants were purchased by LFC 47 in early 1989. Since that purchase, approximately $3 million was spent to repair and upgrade the plants. The purchase price and all repairs and upgrades were paid with cash through advances from LFC Energy. LFC 47 has no outside debt, equity, or other financing. LFC Energy will similarly fund expenses of start-up and running the Capacity Test.

Following initial purchase by LFC 47, all electrical controls and protective devices were upgraded. The Jefferson turbine was replaced and meticulously balanced. The Jefferson generator was rewound. All manual generator field controls were replaced with electronics. Boiler air capacity and control was increased. All spill contamination from previous operation was remediated and approved spill containment and control equipment was added.

FUEL SOURCES

In late 1992, both plants were fully operational. The plants continued to operate, following the FPC estimated hourly rates, through January, 1994. Sufficient fuel supplies were available to provide in excess of 2000 tons of fuel per plant per week. These fuel supplies generally continue to be available today. In addition, we have been working with a new supply being developed to recycle the local waste steam under Florida's one-third recycling laws. This source anticipates having available in excess of 2000 tons of recycled fuel per week. (The pro forma economic analysis in Attachment 2 anticipates about 750 tons per week, per plant from this source, replacing that portion of conventional wood chips previously purchased from suppliers.) Both plants have been permitted to burn "carbonaceous fuel" which includes paper, cardboard and other similar clean recycled materials. This, in effect, builds in a closed loop with the community supplying fuel and labor and the plant returning generated electricity.

WHY THE PLANTS WERE SHUT DOWN

Under the PPAs, the plants operate on avoided cost rates through december 31, 1994. These rates historically are the lowest from late December through early February. The 1994 operating plan developed for these plants in October, 1993 anticipated shutting down during the first quarter of 1994 (because of the low historical energy rates), then begin final preparations for the Capacity Test in late 1994. However, LFC 47 entered an agreement with Auburndale Power Partners ("APP") in November, 1993, to assign the PPAs to APP, subject to FPC and FPSC approval. The original termination date on the APP agreement was January 31, 1994 intended to allow return to the original operating plan if an APP-FPC consent agreement could not be reached. As this termination date approached, APP and FPC were close to completing their consent to the assignment and the termination date was extended.

On filing of the Petition For Declaratory Statement on April 14, 1994, the termination date was again extended to July 31, 1994, to allow for the anticipated FPSC staff review. The plants were not restarted since FPSC approval was anticipated before July 31, 1994. The APP agreement has again been extended to August 31, 1994.

CURRENT START-UP STATUS

During this elapsed time, verious tasks were completed to keep the plants in start-up condition. All regulatory permit activity continued (both plants have valid air permits in place), an ash agricultural land spreading program was negotiated for subsequent disposal of ash (expected to be signed shortly), and a large transformer struck by lightning has been rewound and should be reinstalled shortly. (It is being reinstalled within a structural steel cage to prevent any damage from future lightning strikes.) The plants have had full time security with plant operators, maintenance supervisors and the plant manager kept on the payroll as the security personnel. During this downtime, routine maintenance such as turning shafts to prevent development of flat spots, circulating lubricating oil through bearings, and other moisture protection procedures have been continued. The plants are therefore in start-up condition with key personnel currently on the LFC Power payroll.

MEETING THE CAPACITY TEST

Each of the generators at the Madison and Jefferson plants are rated to produce in excess of 8.5 MW of power. In November, 1992, a short term test was run in which the Madison plant sustained a gross capacity rate of 8.5 MW and the Jefferson plant sustained a gross capacity rate of 9.0 MW. The tests were run over a two day period to obtain heat balance, efficiency data, and component performance over a range of operating capacity rates. The same plant configuration today can also meet these tests.

MEETING THE CAPACITY FACTOR

The analysis presented in Attachment 1 shows that actual plant availability for the period June - November, 1993, was 81.1%, well in excess of the 70% Capacity Factor required in the PPAs. This was achieved with no spare parts, running only to accumulate operating experience since FPC avoided cost rates did not economically justify operating at maximum capacity and availability. (Note that the wood chip plant in Michigan, owned by LFC Energy and operated by LFC Power, the same entity that will operate and maintain the Madison and Jefferson plants, operates at 93% availability.) Using the average net operating capacity of 7.2 MW for Madison and Jefferson, the 81.1% availability converts to a 68.65% Capacity Factor, without any effort to control output. Using the gross billing option in the PPAs, the average operating net capacity of 7.2 MW increases to a gross actual average capacity of 8.2 MW and the 81.1% availability converts to a 78.18% Capacity Factor, well in excess of the 70% minimum in the PPAs. The plants are in the same operating condition as when this actual data was gathered and can therefore meet the Capacity Factor as required in the PPAs.

PRO FORMA FINANCIALS

Attachment 2 is a computer pro forma financial analysis of expected operating cash flows for LFC 47, operating under the PPAs. Revenue includes a Big Bend fuel based energy rate plus capacity payments stipulated in the PPAs. Operating and maintenance expenses are based on actual LFC Power historical costs incurred. Fuel costs are a combination of readily available bark and shavings (39.6% by weight), chips (22.9% by weight), and recycled material (37.5% by weight). Energy rates and operating and maintenance expenses are inflated at 2.5% per annum. Fuel costs are inflated at 3.0% per annum. Under these assumptions, the plants generate $163,446,522 operating cash (after expenses). At a 15% discount factor, the present value of this cash flow stream is $15,648,412. These pro forma calculations provide excellent financial return and sufficient incentive for continued efficient operation.

If any lingering doubts remain regarding the viability of the Madison and Jefferson plants, you are invited to visit the plants to personally view therir condition.

ATTACHMENT 1

MADISON AND JEFFERSON BIOMASS PLANTS

AVAILABILITY ANALYSIS

Each of the Madison and Jefferson plants has a Standard Offer Contract For The Purchase Of Firm Energy And Capacity From A Qualifying Facility ("PPA") with Florida Power Corporation ("FPC"). Included on Sheet No. 9.302 of Rate Schedule COG-2, Appendix A is the paragraph captioned Calculation of 12 Month Rolling Capacity Factor.

The specified PPA capacity for each plant is 8.5 MW. Under the PPA, each plant must maintain a 70% capacity factor in order to receive capacity payments. Using the definition of capacity factor in COG-2 Appendix A, the plants actually operated at 68.65% capacity factor for the period June through November, 1993 assuming a average output of 7.2 MW. This was accomplished without any special effort (such as spare parts or expedited repairs) in operation or maintenance.

The analysis included 3597 hours of run time over an elapsed time of 4438 hours. The 4438 hours elapsed time was not reduced for any FPC caused disconnect time as allowed in the Capacity Factor calculations, whereas the 3597 hours include all disconnect time since it is derived from the actual FPC metered data for the period. An FPC disconnect of 1.938% of the elapsed time (86 hours over a 6 month period) would have made the Capacity Factor 70% as required under the contract.

The calculated capacity factor of 68.65% differs from an overall capacity factor of between 40 and 50% because the plants were cycled up and down according to the estimated hourly rates provided each day by FPC. At times when the estimated hourly rates were below a certain threshold, the plant output was cut back to 2 to 3 MW. Output was increased only when the FPC estimated rate schedules showed long periods above the rate threshold. This tracking of actual run output compared to the FPC estimated hourly rates is shown on the graphs provided in Attachment 3.

The Madison plant has been tested at a peak output of about 7.7 MW. Jefferson has been tested at a peak of about 8.5 MW. Prior to the capacity start date of January 1,1995, each plant was to have been uprated with modifications to the cooling tower and addition of superheater banks so that peak capacity output would exceed 8.5 MW. The cost to do this work is approximately $250,000 per plant for a total of $500,000 for both plants. Electrical and control uprates have already been completed. As they currently stand, without the cooling tower and superheater uprates, Madison will comfortably sustain 7.2 MW and Jefferson, 7.7 MW. The calculated capacity factor of 68.65% was based on sustaining 7.2 MW as described below.

The above Capacity Factor calculations are all based on a net billing option. Under the PPA, the QF can choose a gross billing option in which all power generated is sold to FPC, and station load requirements are purchased and metered separately. At full operation, station load at each plant is approximately 1.0 MW. This means the capacity used to calculate Capacity Factor above would be 8.2 MW under gross billing rather than 7.2 MW under net billing. Substituting the 8.2 MW average run over the 3597 hours results in a Capacity Factor of 78.19%, well above the 70% minimum in the PPA. Again, this Capacity Factor would be further increased when FPC disconnect time is subtracted from the 4438 hours total elapsed time.

Computer data files have been constructed with hourly actual energy rates, estimated rates and actual plant output. Files were constructed from either Madison or Jefferson data over a period of several months. A computer program was written to count the number of hours in each month during which output exceeded 2.5 MW, the low end when the plant output was deliberately cut back because of low estimated rates. Calculated monthly hours available was then multiplied times the sustainable net capacity of 7.2 MW to get monthly total MW produced. This was then divided by the product of total elapsed hours in the month times contract capacity of 8.5 MW. The result is a calculated capacity factor of 68.65% for the six month period.

The following table is a summary of monthly calculations:

MONTH	RUN HOURS	TOTAL HOURS	RUN %	CAP FACT *
JUNE	579	707	81.9%	69.37%
JULY	589	794	74.2%	62.84%
AUGUST	476	699	68.1%	57.68%
SEPTEMBER	697	766	91.0%	77.08%
OCTOBER	557	712	78.2%	66.27%
NOVEMBER	699	760	92.0%	77.91%
TOTALS	3597	4438	81.1%	68.65%

* These Capacity Factor calculations are based on 7.2 MW and a net billing option. Capacity Factor will exceed 70% under a gross billing option since the internal station load of 1 MW would be added to output increasing it to 8.2 MW.

August 9, 1994

Attachment 2

[illegible] CORPORATION

[illegible]

ASSUMPTIONS

PURCHASE PRICE		TECHNICAL DATA		[illegible]	
PROJECT SPONSORS	1000000	CURRENT PLANT CONDITION		[illegible]	
TOTAL [illegible] COST	1000000	CAPACITY (MW, [illegible])	[illegible]	[illegible]	[illegible]
PROJECT [illegible]	6	HEAT RATE [illegible]	[illegible]	[illegible]	[illegible]
PROJECT EQUITY	1000000	PARASITIC LOAD [illegible]	1.1	[illegible]	5.00%
[illegible]	7	FUEL USE [illegible]	[illegible]	[illegible]	
[illegible] COST [illegible]	[illegible]	[illegible] COST [illegible]	[illegible]	[illegible]	[illegible]
[illegible]		AVAILABILITY	[illegible]		
CAPITALIZED [illegible]	0	[illegible] CONDITION		FUEL	[illegible]
[illegible]	0	CONTRACT CAPACITY [illegible]	[illegible]	[illegible]	[illegible]
[illegible]	15	[illegible] CAPACITY FACTOR	72.30%	[illegible]	[illegible]
[illegible]	12			WOOD CHIPS	[illegible]
[illegible]	[illegible]	NEW CAPACITY [illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	OTHER	[illegible]
[illegible]	0	PARASITIC LOAD [illegible]	[illegible]	OTHER	[illegible]
		[illegible]	[illegible]		[illegible]
		[illegible]	[illegible]	[illegible]	
OPERATION AND MAINTENANCE COST		AVAILABILITY	[illegible]	[illegible] FUEL COST [illegible]	[illegible]
SALARIES	[illegible]	[illegible] CAPACITY FACTOR	[illegible]	[illegible] COST [illegible]	[illegible]
REPAIRS	[illegible]	[illegible]		FUEL COST [illegible]	[illegible]
SERVICES	[illegible]				
PROPERTY TAX	[illegible]	[illegible]		MAJOR MAINTENANCE	
INSURANCE	[illegible]	[illegible]	[illegible]	FIRST YEAR [illegible]	[illegible]
UTILITIES	[illegible]	[illegible]	[illegible]	[illegible] YEAR [illegible]	[illegible]
PERMITS, OTHER	[illegible]	[illegible]	[illegible]	CYCLE (YRS)	3
[illegible]	[illegible]			[illegible]	[illegible]
TOTALS	[illegible]			[illegible]	[illegible]
EMERGENCY SERVICE [illegible]					

APPENDIX B

Page 12

LFC ENERGY CORPORATION
MADISON AND JEFFERSON [illegible] PLANTS

REVENUES

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ENERGY RATE [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CAPACITY PMT [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ENERGY MADISON [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CAPACITY FACTOR (%)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ENERGY JEFFERSON [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CAPACITY FACTOR (%)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MADISON ENERGY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MADISON CAPACITY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JEFFERSON ENERGY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JEFFERSON CAPACITY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL ENERGY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL CAPACITY [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL REVENUE ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

FUEL COST

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
MADISON FUEL USED [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MADISON FUEL COST [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JEFFERSON FUEL USED [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JEFFERSON FUEL COST [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MADISON FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
JEFFERSON FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

[illegible]

[illegible] CORPORATION

[illegible]

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
[illegible]	0	0	[illegible]	0	0	0	0	[illegible]	0	0	0	0	[illegible]	0	0	0	0	[illegible]	0	0	0
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EMERGENCY SERVICE FEE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ASH DISPOSAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL OPERATING COSTS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CASH FLOW SUMMARY

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
TOTAL ENERGY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL CAPACITY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL REVENUE ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL OPERATING COSTS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOTAL EXPENSES ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OPERATING CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

DEBT SERVICE

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
INTEREST	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXISTING DEBT SERVICE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEBT SERVICE RATIO	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ADDITIONAL PRINCIPAL PMTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL DEBT SERVICE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

[illegible]

[illegible]

YEAR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
ENERGY RATE ($/MWH)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
CAPACITY RATE ($/KW/MONTH)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
ENERGY [illegible] (MWH/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
CAPACITY FACTOR (%)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
ENERGY [illegible] (MWH/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
CAPACITY FACTOR (%)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] ENERGY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible] CAPACITY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible] ENERGY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible] CAPACITY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL ENERGY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL CAPACITY ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL REVENUE ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

FUEL COST

YEAR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] FUEL USED (T/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] FUEL COST ($/T)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] FUEL USED (T/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] FUEL COST ($/T)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible] FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible] FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
MANAGEMENT SERVICE FEE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
ASH DISPOSAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL OPERATING COSTS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CASH FLOW SUMMARY

YEAR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL REVENUE ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL FUEL COST ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL OPERATING COSTS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
TOTAL EXPENSES ($/YR)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
OPERATING CASH FLOW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

DEBT SERVICE

YEAR	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
INTEREST	0	0	0	0	0	0	0	0	0	0
PRINCIPAL	0	0	0	0	0	0	0	0	0	0
[illegible] DEBT SERVICE	0	0	0	0	0	0	0	0	0	0
DEBT SERVICE RATIO	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
ADDITIONAL PRINCIPAL PMTS	0	0	0	0	0	0	0	0	0	0
TOTAL DEBT SERVICE	0	0	[illegible]	0	0	0	0	0	0	0

ATTACHMENT 2

Forecasted Cogeneration Payments for LFC

Year		Existing Contract	FPC's current avoided unit
	1995	$5,288,657	$4,555,544
	1996	$5,831,812	$5,234,988
	1997	$5,951,065	$5,544,678
	1998	$6,248,089	$5,814,104
	1999	$6,468,834	$5,888,304
	2000	$6,788,402	$6,087,810
	2001	$7,162,274	$6,280,743
	2002	$7,457,007	$6,184,834
	2003	$7,850,436	$6,411,293
	2004	$8,289,308	$6,850,707
	2005	$8,682,451	$7,022,473
	2006	$9,121,319	$7,250,064
	2007	$9,584,761	$7,481,372
	2008	$10,074,822	$7,716,531
	2009	$10,583,545	$7,955,878
	2010	$11,138,883	$8,198,858
	2011	$11,718,988	$8,446,517
	2012	$12,328,879	$8,[illegible],509
	2013	$12,977,585	$8,956,095
	2014	$13,662,083	$9,216,437
	2015	$14,388,585	$9,482,708
	2016	$15,156,987	$9,754,884
	2017	$15,971,442	$10,030,748
	2018	$16,833,877	$10,312,880
	2019	$17,747,855	$10,800,708
	2020	$18,716,561	$10,894,404
	2021	$19,744,781	$11,194,181
	2022	$20,834,380	$11,500,286
	2023	$21,833,324	$11,812,917
	2024	$22,882,851	$12,132,319
	NPV @ 8.95%	$91,252,139	$70,836,334

ATTACHMENT 2

Forecasted Cogeneration Payments for LFC

Year	Existing Contract	FPC's current avoided unit
1995	$5,288,657	$4,565,544
1996	$5,831,912	$5,234,988
1997	$5,951,065	$5,544,678
1998	$6,248,089	$5,814,104
1999	$6,488,834	$5,898,304
2000	$6,798,402	$6,087,610
2001	$7,162,274	$6,280,743
2002	$7,457,907	$6,184,834
2003	$7,858,436	$6,411,283
2004	$8,289,398	$6,850,707
2005	$8,682,451	$7,022,473
2006	$9,121,319	$7,250,084
2007	$9,584,761	$7,481,372
2008	$10,074,822	$7,716,531
2009	$10,583,545	$7,955,878
2010	$11,138,893	$8,198,958
2011	$11,718,989	$8,446,517
2012	$12,328,979	$8,698,509
2013	$12,977,585	$8,955,095
2014	$13,662,083	$9,216,437
2015	$14,388,585	$9,482,708
2016	$15,155,887	$9,754,084
2017	$15,971,442	$10,030,748
2018	$16,833,977	$10,312,890
2019	$17,747,655	$10,600,708
2020	$18,716,561	$10,894,404
2021	$19,744,781	$11,194,191
2022	$20,834,380	$11,500,286
2023	$21,833,324	$11,812,917
2024	$22,862,651	$12,132,319
NPV @ 8.95%	$91,252,139	$70,636,334

ATTACHMENT B
COMPARISION BETWEEN SCENARIO 1 AND 3

Year	Production Cost Scenario 3 PM940022 Base ($)	Scenario 1 PM940025 ($)	Annual Savings ($)	Cummulative Net Present Worth Savings($)
1995	843,459,074	843,933,389	474,315	474,315
1996	957,829,586	958,409,784	580,198	1,006,851
1997	1,028,558,205	1,029,158,138	599,933	1,512,266
1998	1,144,542,078	1,145,242,510	700,432	2,053,873
1999	1,189,591,190	1,190,336,456	745,266	2,582,808
2000	1,297,118,687	1,297,951,509	832,822	3,125,329
2001	1,347,860,166	1,349,593,300	1,733,134	4,161,589
2002	1,420,469,971	1,421,364,408	894,437	4,652,450
2003	1,487,869,622	1,488,735,038	865,416	5,088,371
2004	1,607,440,696	1,608,470,186	1,029,490	5,564,338
2005	1,674,579,109	1,675,813,029	1,233,920	6,087,956
2006	1,754,961,869	1,756,266,403	1,304,534	6,596,064
2007	1,835,344,629	1,836,719,777	1,375,148	7,087,676
2008	1,915,727,390	1,917,173,152	1,445,762	7,562,074
2009	1,996,110,150	1,997,626,526	1,516,376	8,018,768
2010	2,076,492,910	2,078,079,900	1,586,990	8,457,466
2011	2,156,875,670	2,158,533,274	1,657,603	8,878,042
2012	2,237,258,431	2,238,986,648	1,728,217	9,280,514
2013	2,317,641,191	2,319,440,022	1,798,831	9,665,018
2014	2,398,023,951	2,399,893,396	1,869,445	10,031,789
2015	2,478,406,711	2,480,346,770	1,940,059	10,381,148
2016	2,558,789,472	2,560,800,144	2,010,673	10,713,476
2017	2,639,172,232	2,641,253,518	2,081,286	11,029,218
2018	2,719,554,992	2,721,706,892	2,151,900	11,328,856
2019	2,799,937,752	2,802,160,266	2,222,514	11,612,903
2020	2,880,320,513	2,882,613,641	2,293,128	11,881,900
2021	2,960,703,273	2,963,067,015	2,363,742	12,136,403
2022	3,041,086,033	3,043,520,389	2,434,356	12,376,977
2023	3,121,468,793	3,123,973,763	2,504,969	12,604,193
2024	3,201,851,554	3,204,427,137	2,575,583	12,818,623
		Total	$46,550,480	

1. From 1995-2004, values and associated savings are PROMOD system production costing runs. From 2005-2024, values are projected.

2. Net Present Value savings based on FPC's current cost of money (8.95%).

APPENDIX B