

Thomas E Lauria
State Bar No. 11998025
Craig H. Averch
State Bar No. 01451020
WHITE & CASE LLP
Wachovia Financial Center
200 South Biscayne Blvd.
Miami, FL 33131
Telephone: (305) 371-2700
Facsimile: (305) 358-5744

Robin Phelan
State Bar No. 15903000
Judith Elkin
State Bar No. 06522200
HAYNES AND BOONE, LLP
901 Main Street
Suite 3100
Dallas, TX 75202
Telephone: (214) 651-5000
Facsimile: (214) 651-5940

ATTORNEYS FOR THE DEBTORS AND DEBTORS-IN-POSSESSION

**IN THE UNITED STATES BANKRUPTCY COURT
FOR THE NORTHERN DISTRICT OF TEXAS
FORT WORTH DIVISION**

_____)	
In re)	Chapter 11 Case
)	
MIRANT CORPORATION, <u>et al.</u> ,)	Case No. 03-46590 (DML)
)	Jointly Administered
Debtors.)	
)	Date and Time: May 5, 2004
_____)	10:30 a.m.

**DEBTORS' MOTION TO REJECT BOSQUE TOLLING AGREEMENT
BETWEEN DEBTOR MIRANT AMERICAS ENERGY MARKETING LP AND
DEBTOR MIRANT TEXAS, LLC**

TO THE HONORABLE D. MICHAEL LYNN, UNITED STATES BANKRUPTCY JUDGE:

Mirant Americas Energy Marketing, LP ("MAEM") files this Motion (the "Motion") pursuant to section 365(a) of title 11, United States Code (11 U.S.C. §§ 101 et seq., as amended) (the "Bankruptcy Code") for authority to reject that certain "Tolling Agreement" between MAEM and Mirant Texas, LLC ("Mirant Texas"), both of which are Debtors herein. In support thereof, MAEM represents as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction to consider this matter pursuant to 28 U.S.C. §§ 157 and 1334. This is a core proceeding pursuant to 28 U.S.C. § 157(b). Venue is proper before this Court pursuant to 28 U.S.C. §§ 1408 and 1409. MAEM respectfully highlights that the Tolling Agreement is not a contract over which the Federal Energy Regulatory Commission (“FERC”) has jurisdictional authority. The Tolling Agreement involves the generation and sale of energy within the Electric Reliability Council of Texas (“ERCOT”), which is located wholly within the State of Texas. For that reason, the Tolling Agreement is subject to the jurisdiction of the Texas Public Utility Commission (“PUCT”) rather than FERC. Consequently, there are no jurisdictional impediments to granting the Motion.

II. PROCEDURAL BACKGROUND

2. The Cases. On July 14, 2003 and various dates thereafter (collectively, the “Petition Date”), Mirant Corporation and 82 of its direct and indirect subsidiaries (collectively, the “Debtors”) filed voluntary chapter 11 petitions. The Debtors manage and operate their businesses as debtors-in-possession pursuant to sections 1107 and 1108 of title 11 of the United States Code (the “Bankruptcy Code”).

3. The Cases are Jointly Administered. This Court has entered orders approving the joint administration of the Debtors’ chapter 11 cases.

4. The Committees. Three official committees (collectively, the “Committees”) have been appointed by the Office of the United States Trustee for the Northern District of Texas in these administratively consolidated cases.

III. FACTUAL BACKGROUND

5. Under the Bosque Tolling Agreement, a copy of which is attached hereto as Exhibit A,¹ MAEM acquired “tolling rights” to two generating units (297 MW) located at the Bosque facility. The Bosque plant and facility is owned by Mirant Texas, a Debtor herein. Generally, tolling rights provide an acquirer with rights to certain designated output generated by a facility in exchange for, among other things, certain fixed and variable payments. In addition, the acquirer of tolling rights is responsible for providing all fuel necessary to operate the tolled portion of the facility.

6. In 2003, MAEM paid Mirant Texas approximately \$12.8 million in tolling payments for 297 MW of capacity at the Bosque facility pursuant to the Tolling Agreement.

7. The Tolling Agreement expires June 30, 2005.

8. MAEM has carefully analyzed the Bosque Tolling Agreement and determined that from May 2004 through June 30, 2005, the Bosque Tolling Agreement is approximately \$10.6 million “out of the money” as to MAEM. Thus, the contract is burdensome to the MAEM estate and should be rejected.

9. The Tolling Agreement is an intercompany agreement between two Debtors. The Debtors have previously indicated to the Committees and other interested parties that it was the Debtors’ intention to not reject intercompany agreements at this stage of the Bankruptcy case, but to resolve the intercompany issues in connection with a Plan of Reorganization. However, in formulating their business plan, MAEM has determined that the economic impact of the Bosque Tolling Agreement is simply too significant to postpone the

¹ Not all parties were served with the Exhibit. Any party may make a written request therefor directly to Debtors’ counsel.

decision (and continue the economic loss to MAEM) until Plan confirmation. Indeed, to defer an issue of the magnitude represented by the Bosque Tolling Agreement to Plan confirmation would provide inaccurate and potentially misleading information to creditors reviewing the Debtors' business plan. Based upon the foregoing, in light of the duty to fully disclose material matters relating to reorganization, rejection of the Bosque Tolling Agreement at this time is necessary and appropriate.² Indeed, the financial impact of such rejection has already been incorporated into the Debtors' business plan. Finally, there is currently no bar date for filing proofs of intercompany claims. Accordingly, the rejection claim of Mirant Texas will not need to be filed at this time. (The foregoing will also be clear in the order approving the Motion, if granted.)

IV. RELIEF REQUESTED

10. By this Motion, MAEM hereby seeks approval of the rejection of the Tolling Agreement under section 365 of the Bankruptcy Code.

V. BASIS FOR RELIEF

11. Section 365(a) of the Bankruptcy Code provides that a debtor-in-possession, "subject to the court's approval, may assume or reject an executory contract of the debtor." 11 U.S.C. § 365(a). An executory contract is defined as one where material performance is due on both sides such that the failure of either party to complete performance would constitute a material breach of the contract excusing performance of the non-breaching party. See *In re Liljeberg Enterprises, Inc.*, 304 F.3d 410, 436 (5th Cir. 2002); *In re Murexco Petroleum, Inc.*, 15 F.3d 60, 62-63 (5th Cir. 1994).

² The Debtors specifically highlight, however, that it is their intention to deal with other intercompany issues in connection with a Plan of reorganization. Therefore, the relief requested in this Motion is a rare exception to the foregoing general rule.

12. The Tolling Agreement is an executory contract because it requires (i) Mirant Texas to operate the Bosque plant and sell the output therefrom to MAEM and (ii) MAEM to pay for such output. Therefore, the Tolling Agreement is an executory contract that may be rejected under section 365 of the Bankruptcy Code. *See, e.g., In re El Paso Refinery, L.P.*, 220 B.R. 37, 39 n.1 (Bankr. W.D. Tex. 1998) (contract requiring debtor to provide jet fuel to government held to be executory); *In re Cajun Power Cooperative, Inc.*, 230 B.R. 693, 702 (Bankr. D. La. 1999) (supply contracts entered into by debtor electric cooperative held executory).

Rejection Of the Tolling Agreement Is Within MAEM's Business Judgment.

13. As noted previously, rejection of an executory contract requires court approval. A debtor's decision to assume or reject will be approved, provided that it meets the "business judgment" test, pursuant to which rejection of an executory contract is appropriate if such rejection would benefit the estate. *See Richmond Leasing v. Capital Bank, N.A.*, 762 F.2d 1303, 1309 (5th Cir. 1985); *In re G.I. Indus., Inc.*, 204 F.3d 1276, 1282 (9th Cir. 2000) ("[A] bankruptcy court applies the business judgment rule to evaluate a trustee's rejection decision..."); *In re Food Barn Stores, Inc.*, 107 F.3d 558, 567 n. 16 (8th Cir. 1997) (debtor's request to assume or reject contract should be approved where not manifestly unreasonable or made in bad faith).

14. The "business judgment" test is satisfied where the assumption or rejection of an executory contract enhances the value of the estate. *See Richmond Leasing*, 762 F.2d at 1309. Upon a finding that a debtor has exercised sound business judgment in determining whether to assume or reject an executory contract, a court should approve the decision pursuant to section 365(a) of the Bankruptcy Code. *See NLRB v. Bildisco & Bildisco*, 465 U.S. 513, 523 (1984). "The fundamental purpose of reorganization is to prevent a debtor

from going into liquidation, with an attendant loss of jobs and possible misuse of economic resources.” *Bildisco*, 465 U.S. at 528 (citing H.R.Rep. No. 95-595, p. 220 (1977)).

15. MAEM has determined, in its reasonable business judgment, that the Tolling Agreement should be rejected because it is uneconomical and an impediment to ongoing business operations. In this case, rejection of the Tolling Agreement is well within MAEM’s sound business judgment.

16. As noted, the Tolling Agreement is significantly “out of the money” as to MAEM. If the Motion is granted, a new agreement that reflects current market realities will be reached between MAEM and Mirant Texas. Such an agreement would be substantially identical to similar form agreements whereby Mirant Texas would pay MAEM an allocated share of overhead costs, MAEM would administer contracts with third parties (e.g., conduct bidding and scheduling from the asset), and Mirant Texas would receive the net monetary benefits (i.e., the gross revenues from power sales less expenses/costs of fuel). Thus, the energy generated by Mirant Texas will be sold and marketed by MAEM, albeit at more reasonable prices. If the Motion is not granted the Tolling Agreement will result in significant ongoing losses to MAEM.

17. MAEM’s reasonable business judgment is that rejection of the Tolling Agreement is necessary for the reasons stated herein.

18. In discussing the propriety of the Motion with the Committees, the MAG Committee has indicated that the foregoing analysis is not appropriate. Rather, the MAG Committee has asserted that in a “dual debtor” situation (i.e., both counterparties are debtors in bankruptcy), this Court must “balance the equities” and take into account the right of Mirant Texas to assume the Tolling Agreement. The authority for such a proposition is scant and unpersuasive. For example, in *In re Midwest Polychem, Ltd.*, 61 B.R. 559 (Bankr. N.D. Ill.

1986), the Court denied a motion to reject a contract where the counter-party was a debtor in its own, separate bankruptcy case. The court reasoned:

Since the bankruptcy court is a court of equity, this court believes that it is appropriate to always consider the equities of the situation and measure the relative effects of rejection before granting approval. Even in the application of the so-called “business judgment” test, other courts have recognized that the relative equities must come into play. *See In re Chi-Feng Hang*, 23 B.R. 798, 801 (9th Cir. 1982) [internal citation omitted]. The balancing of the equities is especially necessary where, in a case like the instant one, **one Chapter 11 debtor formally requests rejection of an executory contract and another Chapter 11 debtor effectively seeks assumption.**

Id. at 562 (emphasis added).

19. Notably, however, the Court in *Midwest Polychem* stated that “this court need not choose between the “business judgment” test or the equity-balancing test for the result under either test is the same after considering the equities: this court cannot approve Polychem’s rejection.” *Id.* at 562. The court denied the motion because the moving party’s intent in rejecting the contract was to avoid complying with a covenant not to compete. The Court concluded that allowing the debtor “to reject this contract with the information before this court makes no business or equitable sense.” *Id.* at 563. Thus, the business judgment rule was not satisfied.

20. The *Midwest Polychem* case is therefore distinguishable because MAEM has satisfied the business judgment test for rejecting the Tolling Agreement. There is no nefarious purpose or intent underlying the request, but rather, the Motion is filed to rid the MAEM estate of a burdensome contract.

21. In another case, *In re Sun City Investments, Inc.*, 89 B.R. 245 (Bankr. MD. Fla. 1988), the Court again refused to endorse the “balancing of the equities” test in a dual debtor situation. Indeed, the Court in that case noted that “the effect of the rejection on the innocent

third-party or buyer is not an appropriate factor for the Court to consider.” *Id.* at 249. In that case, applying the business judgment rule, the Court denied the motion to reject an asset purchase agreement because the debtor “failed to produce any credible evidence that rejection would benefit the estate or result in a successful reorganization.” *Id.* The *Sun City* court noted that even if the “balancing of the equities” test applied, the equities favored denying the motion to reject because of the size of the counter-party’s rejection claim and the resulting termination of the counter-party’s successful business. *Id.*

22. As noted, MAEM does not believe that the “balancing of the equities” test applies as a general matter. *See, e.g., In re A.J. Lane & Co.*, 107 B.R. 435, 440-41 (Bankr. Mass. 1989) (agreeing with weight of Code authority applying business judgment standard to rejection of executory contract under section 365[a], eschewing "balancing of the equities approach" or requirement that debtor show performance of contract would be burdensome); *see also Lubrizol Enters., Inc. v. Richmond Metal Finishers, Inc.*, 756 F.2d 1043, 1046-47 (4th Cir. 1985), *cert. denied sub nom. Lubrizol Enters., Inc. v. Canfield*, 475 U.S. 1057 (1986) (debtor's decision to reject executory contract should "be accorded the deference mandated by the sound business judgment rule as generally applied by courts to discretionary actions or decisions of corporate directors," and approved unless "so manifestly unreasonable that it could not be based on sound business judgment, but only on bad faith, or whim or caprice").

23. MAEM also contends that the “balancing of the equities” test does not apply in this case. However, if this Court were to “balance the equities,” the balance tips in favor of granting the Motion. Initial analysis indicates that the MAEM estate will be subject to hundreds of millions of dollars of third party claims. The third party claims against Mirant Texas are paltry by comparison. Also, it is highly likely that the payout to Mirant Texas

creditors will be a significantly greater percentage than that made to MAEM creditors. While there will likely be intercompany issues between Mirant Texas and MAEM, those will be resolved equitably in connection with a plan of reorganization.³ As noted previously, there is no bar date for intercompany claims.

24. Moreover, rejection of the Tolling Agreement will not result in any job loss or the termination of the business operations of Mirant Texas. An intercompany agreement, and possibly a new tolling agreement with a third party, will be executed and Mirant Texas will be paid for its generation at prices that are more akin to the market. This point is important because rejection of the Tolling Agreement will not result in an unduly negative impact to Mirant Texas. Rejection of the Tolling Agreement will simply reduce the above-market profit margin Mirant Texas currently enjoys under the Tolling Agreement. The above-market position held by Mirant Texas is currently enjoyed at the expense of the MAEM estate.⁴ A new contract with market-based rate profit margins is most fair and equitable for both estates.

25. Thus, assuming *arguendo* that the “balancing of the equities” test applies, the equities favor granting the Motion.

³ The Order approving the Motion will contain language reasonably acceptable to the Committees to preserve their allocation arguments.

⁴ In this regard, MAEM reserves all rights under Bankruptcy Code section 503 to seek reimbursement of postpetition payments made to Mirant Texas in excess of that to which Mirant Texas was entitled to under applicable bankruptcy law.

VI. CONCLUSION

WHEREFORE, based upon the foregoing, MAEM requests that the Court grant the relief requested herein, and any other relief that is necessary and proper.

Dated: April 12, 2004

HAYNES AND BOONE, LLP
901 Main Street
Suite 3100
Dallas, TX 75202
(214) 651-5000

By Ian T. Peck
Robin Phelan
State Bar No. 15903000
Judith Elkin
State Bar No. 06522200
Ian T. Peck
State Bar No. 24013306

-and-

Thomas E Lauria
TX State Bar No. 11998025
Craig H. Averch
TX State Bar No. 01451020
WHITE & CASE LLP
Wachovia Financial Center
200 South Biscayne Blvd.
Miami, Florida 33131
(305) 371-2700

**ATTORNEYS FOR THE DEBTORS AND
DEBTORS-IN-POSSESSION**

CERTIFICATE OF SERVICE

The undersigned hereby certifies that he provided a true and correct copy of the forgoing to Bankruptcy Services, LLC and directed them to effect service upon all persons on the Limited Service List (without exhibit) via U.S. mail, first class, and the addressees set forth below via U.S. mail, first class (with exhibit) on the 12th day of April 2004.

Eric J. Taube
Mark C. Taylor
Hohmann, Taube & Summers, L.L.P.
100 Congress Avenue
Suite 1600
Austin, TX 78701

Howard L. Siegel
Brown Rudnick Berlack Israels LLP
City Place I, 185 Asylum Street
Hartford, CT 06103-3401

William R. Baldiga
Brown Rudnick Berlack Israels LLP
One Financial Center
Boston, MA 02111

Edward S. Weisfelner
Leslie H. Scharf
Brown Rudnick Berlack Israels LLP
120 West 45th Street
New York, NY 10036

Paul N. Silverstein
Andrews & Kurth, L.L.P.
805 Third Avenue
New York, NY 10022

Jason S. Brookner
Andrews & Kurth, L.L.P.
1717 Main Street
Suite 3700
Dallas, TX 75201

Deborah D. Williamson
Thomas Rice
Cox & Smith Incorporated
112 East Pecan Street
Suite 1800
San Antonio, TX 78205-1505

Bruce R. Zirinsky
Gregory Petrick
Angela Somers
Cadwalader, Wickersham & Taft
100 Maiden Lane
New York, NY 10038

Mark Thompson
Simpson Thacher & Bartlett
425 Lexington Avenue
New York, NY 10017-3954

Federal Energy Regulatory Commission
Attn: Dennis Lane
888 First Street, NE
Washington, DC 20426

ERCOT
7620 MetroCenter Drive
Austin, Texas 78744
Attn: Legal Department

Public Utility Commission of Texas
1701 N. Congress Avenue
P.O. Box 13326
Austin, Texas 78711-3326
Attn: Legal Department

Ian T. Peck

EXHIBIT “A”
Part 1

October 8, 1999

Richard J. Pershing
President
Southern Energy Texas (G.P.), Inc., as
general partner in SEI Texas, L.P.
900 Ashwood Parkway, Suite 500
Atlanta, GA 30338

RE: Tolling Agreement Letter Agreement
between Southern Company Energy
Marketing L.P. and SEI Texas, L.P.

Dear Rick:

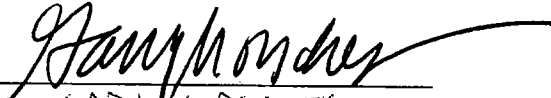
This Tolling Agreement Letter Agreement (the "Letter Agreement") between Southern Company Energy Marketing L.P. ("SCEM") and SEI Texas, L.P. ("SEI Texas") (collectively, the Parties) sets forth the understanding of the Parties regarding the business arrangement for SCEM to purchase the output of a 297 MW combustion turbine facility to be constructed by SEI Texas in Bosque County, Texas.

By executing this Letter Agreement, SEI Texas and SCEM agree to negotiate in good faith to execute a definitive Tolling Agreement which is consistent with the terms and conditions set forth in Appendix A hereto. Until SEI Texas and SCEM are able to execute such agreement, the business arrangement between the Parties shall be governed by the terms and conditions of this Letter Agreement (including Appendix A), which the Parties agree sets forth all material terms of their contractual relationship. This Letter Agreement shall be governed by the law of the state of Georgia without giving effect to principles of conflicts of law that would cause the law of any state other than Georgia to apply. This Letter Agreement constitutes the entire agreement of the Parties and may only be amended by an instrument in writing signed by each of the Parties. This Letter Agreement shall terminate upon the earlier of (i) execution by the Parties of a definitive Tolling Agreement; or (ii) termination of this Letter Agreement in accordance with the terms and conditions specified in Appendix A.

Appendix A, and all Exhibits and Attachments thereto, are hereby incorporated in this Letter Agreement by reference.

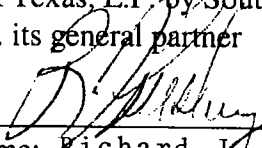
If the foregoing accurately sets forth the agreement of the Parties with respect to the business arrangement described herein, please sign where indicated below and return to my attention.

Sincerely yours,

By: 
Name: GARL MORSCHES
Title: PRESIDENT

ACKNOWLEDGED AND AGREED TO:

SEI Texas, L.P. by Southern Energy Texas (G.P.),
Inc. its general partner

By: 
Name: Richard J. Pershing
Title: EVP & Group President, Americas
Date: October 8, 1999

scheduled COD, provided that Seller will be under no obligation to take any actions that would increase its costs above its planned costs or that would in any way diminish the value of the facility to it in order to achieve such earlier COD. If the Scheduled COD is delayed from June 1, 2000 under clause (iii) of the first sentence of this Section 4 and Seller recovers damages for such delay from the constructor of the gas interconnection facilities, then Seller shall pay to Buyer an amount equal to one-half of (x) the amount of such damages received by Seller that are attributable to the actual delay between June 1, and the actual COD minus (y) those costs incurred by Seller in achieving the actual COD above its planned costs. COD means the facility is mechanically and electrically complete and capable of generating electricity for synchronization with, and delivery into, the transmission grid when scheduled and Seller has all required regulatory approvals to sell electricity. Emissions testing and other tests, as may later be defined, shall be scheduled but not necessarily complete by June 1, 2000. The Seller will make reasonable efforts to complete testing by the scheduled COD. Buyer will take all the capacity and energy from the facility during testing.

5. PERMITTING

Seller will acquire and maintain all permits required to construct, own, and operate the facility. During each calendar year, the hours of operation of the facility shall be limited so that the facility emits no more than twenty-five tons of PM-10 particulate. If the limitation on the emission of PM-10 particulate causes the hours of operation of the facility in any calendar year to be less than one thousand three hundred eighty hours per combustion turbine (full load equivalent and averaged between the two combustion turbines), then such condition shall constitute an event of default by Seller under Section 18. If Seller obtains a Prevention of Significant Deterioration permit (a "PSD Permit") from the Texas Natural Resource Conservation Commission, then all references herein to PM-10 particulate emissions and related limitations on the facility's hours of operation shall no longer be effective and Seller will acquire and maintain permits sufficient to allow the facility to operate at least 4000 hours annually. Seller shall operate the facility in compliance with applicable laws, including applicable rules and regulations of the Public Utility Commission of Texas ("PUCT"). Buyer shall acquire and maintain all permits required for any interconnection facilities on Buyer's side of the delivery points for capacity, energy and fuel. Buyer shall conduct business on Buyer's side of the delivery points in accordance with applicable law, including applicable rules and regulations of the PUCT. Buyer shall transfer all applicable permits to Seller upon expiration of this Agreement or upon termination of this Agreement.

6. CAPACITY

The plant capacity and heat rates are site dependent and dependent upon ambient conditions. Below are the estimated plant capacity, expressed in kilowatts, and heat rate, expressed in Btus per kilowatt hour, for the Bosque County site at ambient conditions of 95 Degrees Fahrenheit Dry Bulb and 60 percent relative humidity at site elevation expressed in feet above Mean Sea Level ("MSL"). The plant capacity and Net Plant Heat Rate ("NPHR") are subject to verification by the combustion turbine manufacturer.

Bosque County - 490 ft. MSL

Capacity - 297,000 kW

Net Plant Heat Rate - 11,002 Btu/kWh (HHV)

The plant capacity and Net Plant Heat Rate are estimated based on receipt of natural gas meeting the specifications set out in Section 7 at the unit filter/fuel gas scrubber system.

7. FUEL

Buyer will provide at no cost to the Seller all fuel required by the facility, including all fuel required for normal startup and testing prior to and after COD, and will pay all associated transportation costs to the fuel delivery points. Seller will reimburse Buyer for fuel required for any optional retest of capacity or heat rate requested by Seller to the extent that the cost of such fuel exceeds the market value of the energy received by Buyer from such retest. All fuel delivered to the facility will meet or exceed minimum specifications consistent with the manufacturer's specifications for the combustion turbines and the permits for the facility. Fuel will consist of natural gas at a minimum pressure of 490 psig (pounds per square inch gauge) at the delivery point and containing a minimum of 50 degrees Fahrenheit superheat and a minimum of 980 Btu per standard cubic foot.

**8. TITLE,
POSSESSION, RISK
OF LOSS, INDEMNITY**

Possession of fuel shall pass from Buyer to Seller at the fuel delivery points. Possession of electricity shall pass from Seller to Buyer at the electricity delivery point. Liability and risk of loss relating to fuel and electricity shall be in the party in possession of the fuel and electricity. Each party agrees to defend, protect, indemnify, and hold harmless the other party from and for any and all liability, claims, and costs arising with respect to fuel and electricity while they are in its possession. Buyer shall hold title to fuel and electricity generated therefrom at all times.

**9. DELIVERY
POINTS**

Seller will deliver the capacity and associated energy to Buyer at the high side interconnections on the unit generator step up transformers.

Buyer shall provide or otherwise arrange for, at no cost to Seller, all electricity needed by the facility for startup that the facility cannot itself provide. Starting and running station service will be netted against the capacity and energy delivered. Natural gas will be delivered by Buyer to Seller at the unit filter/fuel gas scrubber system.

10. INTER- CONNECTION FACILITIES

- ⇒ Electricity - Seller is responsible for arranging for and paying for all interconnection facilities necessary for Buyer to take delivery of power at the delivery point. Buyer is responsible for arranging and paying for transmission from the delivery point, which is defined as the high voltage side of the generator step-up transformers.
- ⇒ Natural Gas - Buyer is responsible for arranging for all interconnection facilities with the pipeline (the "Pipeline") and shall negotiate and pay any LDC charge. The parties anticipate that the Seller will enter into an agreement with the Pipeline for transportation service that will include (either as a separate charge or embedded in the transportation charge) levelized charges intended to repay the Pipeline for the cost of facilities necessary to interconnect the gas delivery point to the Pipeline's existing facilities over the term of that agreement. The obligations of Seller to the Pipeline will be assumed by Buyer for the term of the Tolling Agreement. If a failure by Buyer to have the necessary interconnection facilities in place and operational by March 1, 2000 causes a delay in the COD beyond June 1, 2000, then Seller shall be excused from performing its obligations under the agreement to the extent that Seller's performance is affected by such failure but Buyer's obligation to make capacity payments shall not begin until COD actually occurs. Any failure by Buyer to have the necessary interconnection facilities continue to be operational thereafter or to provide all fuel required by the facility shall excuse Seller from performing its obligations under the agreement to the extent that Seller's performance is affected by such failure, but will not affect Buyer's obligation to make capacity payments. Buyer may place such facilities on Seller's site as are reasonably necessary to provide natural gas with the characteristics specified in Section 7 to the specified delivery points set out in Section 9 and which do not interfere with Seller's use, operation, or maintenance of Seller's facilities.

11. O&M

Seller shall operate and maintain the facility in accordance with the combustion turbine manufacturer's published recommendations, which may include Technical Information Letters ("TILs") provided to Seller after COD at Seller's discretion. By January 1, 2000 and by

each January 1st thereafter during the term unless Seller has in effect a PSD Permit for the facility, Seller shall provide Buyer a good faith estimate of the number of hours the facility is expected to be available at full load equivalent during that calendar year. By February 1, 2000, Seller shall provide Buyer a schedule of all planned outages for the twelve months beginning with the COD based on the Buyer's projections of the dispatch of the facility, which shall be provided to Seller by January 15, 2000 and shall contain the estimated number of starts by unit and the estimated operating hours by unit. At least three (3) months prior to each anniversary of the COD, Seller shall notify Buyer of the planned outages to occur during the twelve months beginning on such anniversary of the COD. At least three and a half (3★) months prior to each anniversary of the COD, Buyer shall provide Seller projections of the dispatch of the facility during the twelve months following such anniversary, which shall contain the estimated number of starts by unit and the estimated operating hours by unit. Within 30 days of receipt of a schedule of planned outages, Buyer may request reasonable changes therein. Seller and Buyer will work together to schedule planned outages taking into account: (i) each party's requirements and (ii) outages scheduled for the generating facilities owned by Brazos Electric Power Cooperative so long as Buyer is entitled to the output of such generating facilities, with Buyer considering its other resources and expected loads in requesting such reasonable modifications; provided that in the event of a disagreement, the number and duration of all planned outages shall be determined by Seller consistent with manufacturer's maintenance recommendations, TILs and prudent electrical practices. Seller may vary the number or duration of actual planned outages during the twelve month period based upon the manufacturer's maintenance recommendations, TILs and prudent electrical practices and in light of the actual dispatch of the facility. No planned outages shall be scheduled to occur during on-peak hours during June through September other than outages for off-line water washes, which are required for each unit after approximately 720 cumulative hours of operation. During the course of the year Buyer may request, upon reasonable advance notice to Seller, changes in Seller's maintenance schedule for the facility. In considering Buyer's requested changes Seller will consider the manufacturer's maintenance recommendations, published TILs, prudent electrical practices, the facility's point in the maintenance cycle and the potential impacts to the facility if maintenance is deferred, and shall advise Buyer of Seller's position. Seller will utilize reasonable efforts to make such schedule changes on the request of Buyer that are determined by Seller in its reasonable discretion not to be a detriment to the facility or Seller's obligations for performance under this Agreement.

12. PLANT SCHEDULE CONTROL

Buyer has the right to start the facility and to schedule it fully upon reaching minimum load within the design limits of the facility and subject to a mutually agreed upon Operating Protocol that shall include:

- ⇒ Minimum run time per unit after completion of a successful start is 2 hours
- ⇒ Buyer may not start a unit unless it has been off-line for at least one hour
- ⇒ Minimum unit load is 50% of unit capacity at current ambient conditions
- ⇒ The ramp rate per unit in response to a dispatch request from the minimum unit load described above is 8.33% of full load rating, at current ambient conditions, per minute
- ⇒ Maximum number of starts per day per unit is 3
- ⇒ After approximately 720 cumulative hours of operation for a unit, the unit will be off-line for approximately 48 hours for water wash
- ⇒ By 4:00 p.m. Central Prevailing Time on each day, Buyer will provide Seller with its best estimate of the expected facility dispatch for the 24 hours beginning 12:00 a.m. Central Prevailing Time the following day.

13. IN SERVICE GUARANTEE

For each day up to a maximum of 365 days that the COD is delayed beyond the scheduled COD (as adjusted for any Excused COD Delay, Force Majeure or delays due to Buyer's failure to perform its obligations), Seller shall pay Buyer liquidated damages equal to the additional cost (if any) incurred by Buyer for substitute firm power capped at \$35,000/day with the total of such liquidated damages capped at \$12,800,000.

14. PERFORMANCE GUARANTEES

Seller will provide the following performance guarantees based on 95 Degrees F, 60% relative humidity, at the selected site elevation above MSL (Mean Sea Level):

- ⇒ Capacity of 297.0 MW at ambient conditions of 95 Degrees Fahrenheit Dry Bulb and 60 percent relative humidity at site elevation (such capacity, the "Guaranteed Net Demonstrated Capacity" or "GNDC") tested within the sixty day period prior to COD and thereafter annually in May, as corrected for actual ambient conditions (temperature and relative humidity), load condition or load point of the unit at the time of testing based on the manufacturer's published correction curves (as adjusted by mutual agreement of the parties). Seller may request retests to be performed at any time and will reimburse Buyer for fuel required for any such optional retest to the extent that the cost of

such fuel exceeds the market value of the energy received by Buyer from such retest. Such retests requested by Seller shall not cause Buyer to incur a run charge and shall not count as starts. Buyer may request a retest at any time it reasonably believes that a material adverse change has occurred in the capacity of the facility, or when requested to do so by a regulatory authority, with all costs of such test being borne by Buyer. If the capacity test performed prior to the COD establishes that the capacity of the facility is less than the GNDC, Seller may at its option reduce the GNDC by paying Buyer \$50.00 per kW of reduction. Following the end of each Contract Year (as defined in Section 17), including the last Contract Year that this Agreement is in effect, the Seller will calculate an adjustment to the Annual Capacity Charge (as defined in Section 16) for such Contract Year to reflect the results of any capacity tests performed in such Contract Year (and for the first Contract Year, the capacity test prior to COD). Upon any valid annual test or optional retest of the facility's capacity, the capacity demonstrated by such testing shall be used from such date until the next such valid test. Seller will calculate the weighted average of the values for net demonstrated capacity of the facility established in the last valid capacity test performed prior to the start of that Contract Year and in any valid capacity tests performed during such Contract Year with the weighting to be based upon the number of days in the Contract Year on which each such net demonstrated capacity value was the most current net demonstrated capacity for the facility. That weighted average (the "Average CNDC") will then be compared to GNDC. No adjustment in the Annual Capacity Charge will be made if the Average CNDC of the facility in effect during such Contract Year is within +/- 1.1% of the GNDC (as adjusted by any reduction in the GNDC purchased by Seller based on the capacity test performed prior to COD). To the extent that the Average CNDC of the facility for a Contract Year is outside such deadband, an adjustment will be calculated to the Annual Capacity Charge for such Contract Year as set out in Part I of Exhibit A to this Term Sheet. Such adjustment shall be negative if the Average CNDC of the facility is less than the GNDC and positive if it exceeds the GNDC. Such adjustment shall affect payments between the parties as set forth below.

- ⇒ Heat rate of 11,002 Btu/KWh (HHV) when fueled on natural gas having an average of 1000 Btu per standard cubic foot at ambient conditions of 95 Degrees Fahrenheit Dry Bulb and 60% relative humidity (such heat rate, the "Guaranteed Net Plant Heat Rate"),

as corrected for actual Btu content of the fuel and for actual ambient conditions (temperature and relative humidity) and load condition or load point of the unit at the time of testing based on the manufacturer's published correction curves (as adjusted by mutual agreement of the parties). The heat rate will be tested in conjunction with the annual capacity test described above. Buyer and Seller may request retests at other times under the same conditions as set out above for capacity tests. If the heat rate test performed prior to the COD establishes that the heat rate of the facility is above the Guaranteed Net Plant Heat Rate, then Seller may at its option increase the Guaranteed Net Plant Heat Rate by paying Buyer \$10,000 dollars per one Btu/Kwh of increase. Following the end of each Contract Year, including the last Contract Year that this Agreement is in effect, the Seller will calculate an adjustment to the Annual Capacity Charge for such Contract Year to reflect the results of any heat rate tests performed in such Contract Year (and for the first Contract Year, the heat rate test prior to COD). Upon any valid annual test or optional retest of the facility's heat rate, the heat rate demonstrated by such testing shall be used from such date until the next such valid test in calculating whether any adjustment is to be made. Seller will calculate the weighted average of the values for the net plant heat rate of the facility demonstrated in the last valid heat rate test performed prior to the start of that Contract Year and in any valid heat rate tests performed during such Contract Year with the weighting to be based upon the number of days in the Contract Year on which each such net plant heat rate was the most current demonstrated net plant heat rate for the facility. That weighted average (the "Average Net Plant Heat Rate") will then be compared to the Guaranteed Net Plant Heat Rate. No adjustment in the Annual Capacity Charge will be made if the Average Net Plant Heat Rate of the facility in effect during such Contract Year is within +/- 2.1% of the Guaranteed Net Plant Heat Rate (as adjusted by any increase in the Guaranteed Net Plant Heat Rate purchased by Seller based upon the heat rate test performed prior to COD). To the extent that the Average Net Plant Heat Rate for a Contract Year is outside such deadband, an adjustment will be made to the Annual Capacity Charge for that Contract Year as set out in Part II of Exhibit A to this Term Sheet. Such adjustment shall be negative if the Average Net Plant Heat Rate exceeds the Guaranteed Net Plant Heat Rate and positive if it is less than the Guaranteed Net Plant Heat Rate. Such adjustment shall affect payments between the parties as set forth below.

⇒ Equivalent Availability shall average 98% over all hours in June

through September and shall average 95% over all hours in October through May. Equivalent Availability shall be calculated separately for those two periods using the formula set out below. For any Contract Year, the "Yearly Equivalent Availability" for such Contract Year shall be equal to the sum of (1) the Equivalent Availability calculated for the hours in June through September multiplied by the Summer Factor plus (2) the Equivalent Availability calculated for the hours in October through May multiplied by the Rest of Year Factor. The "Summer Factor" means (i) 33 1/3% if the facility is able to operate at full load equivalent for more than 2000 hours during the Contract Year without exceeding applicable limits on emissions of PM-10 particulate and (ii) if the facility is restricted to operating at 2000 hours or less at full load equivalent during the Contract Year based upon limits applicable to the emissions of PM-10 particulate, 90% minus ten percentage points for each 100 hours that the facility is able to operate in excess of 1500 hours. The "Rest of Year Factor" means 100% minus the Summer Factor. The "Guaranteed Equivalent Availability" of the facility for each Contract Year shall be equal to the sum of (1) 98% multiplied by the Summer Factor and (2) 95% multiplied by the Rest of Year Factor. To the extent that the Yearly Equivalent Availability in a Contract Year differs from the Guaranteed Equivalent Availability, then there shall be an adjustment to the Annual Capacity Charge for such Contract Year equal to (i) the Yearly Equivalent Availability for such Contract Year divided by the Guaranteed Equivalent Availability, (ii) minus one (iii) with the result multiplied by the amount of the Annual Capacity Charge made for such Contract Year net of any other adjustments; provided that no such adjustment shall be made that would increase the Annual Capacity Charge for any Contract Year in which the facility was restricted to operating 2000 hours or less at full load equivalent by restrictions on emissions of PM-10 particulate.

Equivalent Availability Calculation:

$$EA = (PH-FMOH-POH-FOH) / (PH-POH-FMOH)$$

Where:

EA = Equivalent Availability

PH = Hours in the period, provided that if Seller did not have a PSD Permit in effect during any portion of that period, then the number of such hours shall be multiplied by the fraction produced by dividing (i) the

number of hours in the Contract Year that Seller, pursuant to paragraph 11, has informed Buyer the facility can be operated at full load equivalent without exceeding applicable limits on PM-10 particulate (determined by prorating the estimate for each calendar year encompassed by that Contract Year based upon the portion of that calendar year falling within the Contract Year) by (ii) 8760

FMOH = Seller Force Majeure hours

POH = planned outage hours (includes major maintenance hours and off-line water wash hours)

FOH = forced outage hours

- ⇒ Exhibit A to this Term Sheet sets out the formulas for the calculation of the adjustments to the Annual Capacity Charge to reflect the bonuses or penalties for capacity, heat rate, and equivalent availability described above. The adjustments for capacity, heat rate, and equivalent availability described above shall affect the payments between the parties as set forth below.
- ⇒ Amounts owed by either party as a result of the adjustments to Annual Capacity Charge related to capacity, heat rate and equivalent availability will be accounted for in a nominal account and netted following each Contract Year, including the last Contract Year this agreement is in effect. If following any Contract Year, \$500,000 or more is owed to a party, the owing party shall pay the entire amount within 15 days. Upon payment of such amount, the nominal account will be set at zero and adjustments will commence accruing (except following the last Contract Year). If any amount remains in the nominal account following the last Contract Year, the owing party shall pay such amount in 15 days.
- ⇒ Startup
 - Successful Start means synchronization of the unit to the transmission grid within 20 minutes of a start initiation.
 - Normal Start means a unit reaching full load conditions within twenty (20) minutes after a start initiation.
 - Emergency Start means a unit reaching full load conditions within ten (10) minutes after a start initiation.
 - If Buyer requests that both units of the facility be started at the same time, then one unit will start first and upon its synchronization to the transmission grid, the start initiation of the second unit will occur. The total time from start initiation of the first unit to the second unit reaching full load conditions will be 30 minutes for a Normal Start and 20 minutes for an Emergency Start.

If Buyer cancels a scheduled Normal Start or Emergency Start of a unit after start initiation (20 minutes prior to when the unit is to be at full load conditions for a Normal Start and 10 minutes for an Emergency Start), then a successful Normal Start or Emergency Start, as applicable, will be deemed to have occurred.

15. FORCE MAJEURE If a Force Majeure renders Seller wholly or partly unable to perform, Seller shall be excused from performance to the extent so affected. Buyer shall be excused from paying for any capacity made unavailable by a Force Majeure. Force Majeure shall mean an event that renders Seller wholly or partly unable to perform, that is not within the reasonable control of Seller (or in the case of events affecting third parties owing obligations to Seller or the facilities used by third parties to meet such obligations to Seller, not within the reasonable control of such third party) and that Seller (or such third party) is unable to overcome or avoid or cause to be avoided by the exercise of due diligence, including without limitation acts of God; fire; earthquake; lightning, tornado, hurricane, or other severe weather condition affecting operation of the facility; civil disturbance; labor dispute; labor or material shortage; sabotage; acts of terrorism; uprising; insurrection; civil unrest; war or rebellion; explosions not due to lack of proper care or maintenance; or restraint by court order or public or governmental authority (so long as Seller has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such governmental action); and other events of a similar nature that Seller is not able to overcome by the exercise of reasonable due diligence.

16. PRICE

⇒ Capacity payments

- Starting the first full month following COD (unless COD occurs on the first day of a month, in which case starting with that month), \$43.10/kW per year, based on the guaranteed net demonstrated capacity of 297 MW (at ambient conditions of 95 degrees Fahrenheit Dry Bulb and 60 percent relative humidity at site elevation) paid in 12 monthly installments (each such monthly installment, the "Capacity Charge," and the total amount of such 12 installments, the "Annual Capacity Charge"). An adjustment to the Annual Capacity Charge shall be calculated following each Contract Year to reflect net demonstrated capacity, heat rate and equivalent availability, in each case as described in Section 14 above.

⇒ O&M Charge

- For each Contract Year an O&M Charge determined based upon the formula set out in Exhibit B and to be paid in the following manner:

Using Buyer's estimate of the number of starts and hours of operation for the upcoming Contract Year, Seller will estimate the O&M Charge for that Contract Year (such estimate, the "Estimated O&M Charge"). Seller will notify Buyer of that estimate at least two (2) months prior to June 1, 2000 for the first Contract Year and for each subsequent Contract Year, at least two (2) months in advance of such Contract Year. For each Billing Cycle in the Contract Year, Buyer will owe Seller one-twelfth of the amount of the Estimated O&M Charge (such one-twelfth amount, the "Monthly O&M Charge").

Following the first six (6) Billing Cycles of the Contract Year, Seller will calculate what the amount of the O&M Charge would be based upon the actual operation of the facility during that six (6) months (such amount, the "Six Month O&M Amount"). The Monthly O&M Charge owed for the remaining Six Billing Cycles in the Contract Year shall be adjusted upwards or downwards by an amount equal to (i) the Six Month O&M Amount minus (ii) the sum of the Monthly O&M Charges for the first six (6) Billing Cycles in the Contract Year with the result (iii) divided by six (6).

Within five (5) days after the end of the Contract Year, the Seller will calculate and notify Buyer of the amount of the O&M Charge for that Contract Year based upon the actual operation of the facility during that Contract Year (such amount, the "Final O&M Charge"). If the Final O&M Charge exceeds the sum of the Monthly O&M Charges for the Contract Year, the difference will be paid by Buyer to Seller within fifteen (15) days. If the sum of the Monthly O&M Charges for the Contract Year exceeds the Final O&M Charge, the difference will be credited by Seller to Buyer on Seller's next invoice to Buyer or if the Contract Year is the final Contract Year, paid by Seller to Buyer within fifteen (15) days.

- ⇒ Run Charge per Unit - \$258* per Factored Hour (as defined in Exhibit B) on natural gas for the first 22,000 Factored Hours. After the first 22,000 Factored Hours the per run-time charge is \$506*.

⇒ Escalation - Items or amounts (including items or amounts in Exhibit B) marked with an asterisk (*) will escalate. On January 1, 2000 and each January 1st thereafter, the amounts listed shall be adjusted upward or downward by multiplying them by the Escalation Factor. The "Escalation Factor" shall be equal to the Consumer Price Index for All Urban Consumers determined for the month of October of the year prior to the adjustment date divided by the Consumer Price Index for All Urban Consumers for December, 1998, in each case using the First Published Final Index reported by the Bureau of Labor Statistics of the U.S. Department of Labor for such month without seasonal adjustment.

17. BILLING/ PAYMENT

"Contract Year" means (i) for the first Contract Year, the period which begins on the COD and ends (x) if the COD is the first day of a month, the day immediately prior to the first anniversary of the COD or (y) if the COD is not the first day of a month, on the last day of the twelfth full month after the COD and, (ii) thereafter, each subsequent twelve month period, with the last Contract Year ending on the day the Agreement expires or is otherwise terminated in accordance with its terms. "Billing Cycle" means (i) for the first Billing Cycle, the period commencing on the COD and ending (x) if the COD is the first day of a month, on the last day of that month or (y) if the COD is not the first day of a month, on the last day of the first full month occurring after the COD and (ii) thereafter, each calendar month. Seller shall invoice Buyer within five days after the end of each Billing Cycle, which invoice shall set forth the Capacity Charge, O&M Charge and Run Charges owed for such Billing Cycle and any other amounts due Seller. Payment shall be made by the later of (i) the twentieth day of the month in which the invoice is delivered or (ii) the fifteenth day after the date of such invoice. Late payments will accrue interest at prime plus 200 basis points.

18. DEFAULTS/ REMEDIES

The following events shall constitute events of default:

- (a) a failure to make any undisputed payment when due that continues 10 days after written notice,
- (b) a voluntary bankruptcy event or an involuntary bankruptcy event that is not dismissed or vacated in 90 days,
- (c) in the case of Seller, the limitation on the emission of PM-10 particulate causes the hours of operation of the facility in any calendar year to be less than one thousand three hundred eighty hours per combustion turbine (full load equivalent and averaged between the two combustion turbines), and

(d) any other material default in performance not cured within 30 days of written notice or, if such cure cannot be reasonably completed in such 30 day period, within 120 days of such notice.

Upon the occurrence of an event of default, the nondefaulting party may terminate this agreement upon 30 days written notice and exercise any other rights and remedies available at law or in equity; provided that Buyer's remedies for a breach of the in-service guarantee set out in Section 13 or of the performance guarantees set out in Section 14 shall be limited to the remedies and rights specifically set out in such sections, and provided further that Buyer's remedy for a Seller event of default described in clause (c) of the first sentence of this section shall be limited to recovery from Seller of the costs reasonably incurred by Buyer in purchasing electricity from alternative sources to replace the electricity that would have been produced by the facility had it been able to operate one thousand three hundred eighty hours per combustion turbine (full load equivalent and averaged between the two combustion turbines) reduced by the costs avoided by the Buyer as a result of such purchases. Unless expressly herein provided, neither party shall be liable for any consequential, incidental, punitive, exemplary or indirect damages whether by statute, in tort or agreement, under any indemnity provision or otherwise and regardless of the cause or causes of such damages, including the negligence of any party, whether such negligence be sole, joint, or concurrent, or active or passive.

19. CONDITIONS PRECEDENT

- ⇒ Seller is an EWG under PUHCA and under Texas law
- ⇒ Seller has authority to sell at market based rates
- ⇒ Approval by board of directors of SEI and the board of governors of Southern Company Energy Marketing G.P., L.L.C.

20. TERMINATION RIGHTS

If (ii) Seller is unable to get any necessary regulatory approvals pertaining to the construction of the facility on or before August 1, 1999, or obtaining any such necessary regulatory approval would have an actual or potential material adverse effect on any affiliate of Seller (excluding any material adverse effect arising from a reduction in the value of the facility), then Seller can terminate this agreement on 30 days notice without penalty or other obligation to Buyer.

21. ASSIGNMENT

Seller may assign all of its rights and obligations under this agreement to any subsidiary of Southern Energy, Inc. that will own the facility, which subsidiary shall thereafter be the Seller, and upon such assignment Seller shall have no further rights and obligations under this agreement. Either Buyer or Seller may assign this agreement to a lender or lenders to such party or its affiliates and upon such assignment such lender or lenders shall be entitled to copies of any

notices sent to such party and to exercise any cure rights held by such party. The parties may otherwise assign their rights or obligations under this agreement only with the written consent of the other party, which shall not be unreasonably withheld.

22. SECURITY

Buyer will provide customary security to Seller as reasonably required by the lenders. If Buyer is able to maintain an investment grade credit rating additional security is not expected to be necessary. Seller will provide security to Buyer with regard to Seller's payment of any liquidated damages that may become due under the in-service guarantee set out in Section 13 above. After the COD, if Buyer reasonably determines in a manner consistent with standard commercial practices that the amount that is owed by Seller to Buyer under this agreement net of any amounts owed by Buyer to Seller (including amounts that have accrued but for which Seller has not yet submitted an invoice to Buyer) exceeds \$2,000,000 and Seller at such time does not meet the Creditworthiness Criteria (as hereinafter defined), Buyer shall have the right, upon three (3) business days written notice, to require Seller to deliver to Buyer Eligible Collateral (as hereinafter defined) in a reasonable amount. Buyer shall release such Eligible Collateral (or appropriate portions thereof) within three (3) business days after such conditions that gave rise to the requirement to post Eligible Collateral have been fully or partially remedied. "Eligible Collateral" means collateral security for the obligations of Seller to Buyer hereunder in the form of (i) a guarantee from an entity that meets the Creditworthiness Criteria, or (ii) a direct-pay, irrevocable, standby letter of credit from a major U.S. commercial bank having a credit rating of at least "A" from Standard & Poor's Rating Group, or its successor, or "A2" from Moody's Investor Services, Inc. or its successor (each of (i) and (ii) in form and substance approved by Buyer), or (iii) cash, in the form of currency of the United States of America. "Creditworthiness Criteria" means a published or "shadow" credit rating for unsecured indebtedness of either at least "BBB-" from the Standard & Poor's Rating Group (a division of McGraw Hill), or its successor, or at least "Baa3" from Moody's Investor Services, Inc., or its successor; or if a party has neither a published or "shadow" credit rating from either Standard & Poor's Rating Group or Moody's Investor Services, Inc., such party qualifies for unsecured trade credit under the prevailing circumstances from the other party in accordance with other applicable credit criteria of the other party in accordance with its internal credit policies. A "shadow" rating is an unpublished rating by a rating agency indicative of the rating the agency would publish were there any outstanding debt securities of the subject company to rate.

EXHIBIT “A”
Part 2

Exhibit A

I. Adjustment to Annual Capacity Charge based upon Net Demonstrated Capacity during the Contract Year

Following the end of each Contract Year, Seller will calculate the weighted average of the values for net demonstrated capacity of the facility established in the last valid capacity test performed prior to the start of that Contract Year and in any valid capacity tests performed during such Contract Year with the weighting to be based upon the number of days in the Contract Year on which each such net demonstrated capacity value was the most current net demonstrated capacity for the facility. That weighted average (the Average CNDC) will then be compared to the Guaranteed Net Demonstrated Capacity of the facility (the GNDC), and

- (A) If the Average CNDC for the Contract Year is within +/- 1.1% of the GNDC, no adjustment will be made to the Annual Capacity Charge related to net demonstrated capacity for that Contract Year;
- (B) If the Average CNDC exceeds the GNDC by more than 1.1% (i.e. Average CNDC > (1.011 x GNDC)), then the adjustment (the "Capacity Adjustment") to the Annual Capacity Charge for that Contract Year shall be calculated as follows:

$$\text{Capacity Adjustment} = [\text{Average CNDC} - (1.011 \times \text{GNDC})] \times \text{Annual Capacity Charge}; \text{ or}$$

- (C) If the Average CNDC is less than the GNDC by more than 1.1% (i.e., Average CNDC < (0.989 x GNDC)), then the Capacity Adjustment to the Annual Capacity Charge for that Contract Year shall be calculated as follows:

$$\text{Capacity Adjustment} = [\text{Average CNDC} - (0.989 \times \text{GNDC})] \times \text{Annual Capacity Charge}.$$

Examples:

- 1) Average CNDC exceeds GNDC by more than 1.1%:

GNDC	= 297,000 kW
Average CNDC	= 302,000 kW
Annual Capacity Charge	= 43.10 \$/kW per year

Therefore, since

$$302,000 > (1.011 \times 297,000) \\ 302,000 > 300,267$$

$$\text{Capacity Adjustment} \\ = [302,000 - (1.011 \times 297,000)] \times \$43.10$$

$$\begin{aligned}
&= [302,000 - 300,267] \times \$43.10 \\
&= 1,733 \times \$43.10 \\
&= \$ 74,692
\end{aligned}$$

- 2) Average CNDC is less than GNDC by more than 1.1%:

GNDC	= 297,000 kW
Average CNDC	= 292,000 kW
Annual Capacity Charge	= 43.10 \$/kW per year

Therefore, since

$$\begin{aligned}
292,000 &< (0.989 \times 297,000) \\
292,000 &< 293,733
\end{aligned}$$

$$\begin{aligned}
&\text{Capacity Adjustment} \\
&= [292,000 - (0.989 \times 297,000)] \times \$43.10 \\
&= [292,000 - 293,733] \times \$43.10 \\
&= -1,733 \times \$43.10 \\
&= (\$ 74,692)
\end{aligned}$$

II. Adjustment to Annual Capacity Charge based upon Net Plant Heat Rate

Following the end of each Contract Year, Seller will calculate the weighted average of the values for the net plant heat rate of the facility demonstrated in the last valid heat rate test performed prior to the start of that Contract Year and in any valid heat rate tests performed during such Contract Year with the weighting to be based upon the number of days in the Contract Year on which each such net plant heat rate was the most current demonstrated net plant heat rate for the facility. That weighted average (the Average Net Plant Heat Rate) will then be compared to the Guaranteed Net Plant Heat Rate of the facility, and

- (A) If the Average Net Plant Heat Rate for the Contract Year is within +/- 2.1% of the Guaranteed Net Plant Heat Rate, no adjustment will be made to the Annual Capacity Charge related to the net plant heat rate for that Contract Year;
- (B) If the Average Net Plant Heat Rate is less than the Guaranteed Net Plant Heat Rate by more than 2.1% (i.e. Average Net Plant Heat Rate < (0.979 x Guaranteed Net Plant Heat Rate)), then the adjustment (the "Heat Rate Adjustment") to the Annual Capacity Charge for that Contract Year shall be calculated as follows:

$$\begin{aligned}
&\text{Heat Rate Adjustment} = \\
&[\text{net annual electrical output} - (25\text{kWh} \times \text{number of starts in Contract Year})] \times (\text{average} \\
&\text{daily midpoint price per Btu for natural gas-listed in } \underline{\text{Gas Daily}} \text{ for East-Houston-Katy,} \\
&\text{Houston Ship Channel during the Contract Year}) \times [(0.979 \times \text{Guaranteed Net Plant Heat} \\
&\text{Rate}) - \text{Average Net Plant Heat Rate}]; \text{ or}
\end{aligned}$$

- (C) If the Average Net Plant Heat Rate is greater than the Guaranteed Net Plant Heat Rate by more than 2.1% (i.e. Average Net Plant Heat Rate > (1.021 x Guaranteed Net Plant Heat Rate)), then the Heat Rate Adjustment to the Annual Capacity Charge for that Contract Year shall be calculated as follows:

Heat Rate Adjustment =
 [net annual electrical output – (25kWh x # starts in year)] x (average daily midpoint price per Btu for natural gas-listed in Gas Daily for East-Houston-Katy, Houston Ship Channel during the Contract Year) x [(1.021 x Guaranteed Net Plant Heat Rate) – Average Net Plant Heat Rate]

Examples:

- 1) Average Net Plant Heat Rate is less than the Guaranteed Net Plant Heat Rate by more than 2.1%

Guaranteed Net Plant Heat Rate = 11,002 Btu/kWh
 Average Net Plant Heat Rate = 10,602 Btu/kWh
 Net annual electrical output = 1,296,319,200 kWh
 Number of starts in year (140 per unit x 2) = 280
 Annual average daily midpoint price for gas = \$0.0000025/Btu

Therefore, since

$$10,602 < (0.979 \times 11,002)$$

$$10,602 < 10,771$$

Heat Rate Adjustment

$$= [1,296,319,200 - (25 \times 280)] \times 0.0000025 \times [(0.979 \times 11,002) - 10,602]$$

$$= (1,296,319,200 - 7000) \times 0.0000025 \times (10,771 - 10,602)$$

$$= 1,296,312,200 \times 0.0000025 \times 169$$

$$= \$547,692$$

- 2) Average Net Plant Heat Rate is greater than the Guaranteed Net Plant Heat Rate by more than 2.1%

Guaranteed Net Plant Heat Rate = 11,002 Btu/kWh
 Average Net Plant Heat Rate = 11,402 Btu/kWh
 Net annual electrical output = 1,296,319,200 kWh
 Number of starts in year (140 per unit x 2) = 280
 Annual average daily midpoint price for gas = \$ 0.0000025/ Btu

Therefore, since

$$11,402 > (1.021 \times 11,002)$$

$$11,402 > 11,233$$

Heat Rate Adjustment

$$= [1,296,319,200 - (25 \times 280)] \times 0.0000025 \times [(1.021 \times 11,002) - 11,402]$$

$$= (1,296,319,200 - 7000) \times 0.0000025 \times (11,233 - 11,402)$$

$$= 1,296,312,200 \times 0.0000025 \times (-169)$$

$$= (\$547,692)$$

III. Adjustment to Annual Capacity Charge for Equivalent Availability

A. Calculation of Summer EA

The equivalent availability for the hours during a Contract Year falling in the months of June through September (the "Summer EA") shall be calculated as follows:

$$\text{Summer EA} = \frac{(\text{Summer PH} - \text{FMOH} - \text{POH} - \text{FOH})}{(\text{Summer PH} - \text{FMOH} - \text{POH})}$$

Where

Summer PH = hours during the Contract year falling in the months of June through September, provided that if Seller did not have a PSD Permit in effect during any portion of that period, then the number of such hours shall be multiplied by the fraction produced by dividing (i) the number of hours in the Contract Year that Seller has informed Buyer the facility may be operated at full load equivalent without exceeding applicable limits on the emission of PM-10 particulate by (ii) 8760

FMOH = Seller Force Majeure outage hours occurring during June through September

POH = planned outage hours (includes major maintenance hours and off-line water wash hours) occurring during June through September

FOH = forced outage hours occurring during June through September

B. Calculation of Rest of Year EA

The equivalent availability for the hours during a Contract Year falling in the months of October through May (the "Rest of Year EA") shall be calculated as follows:

$$\text{Rest of Year EA} = \frac{(\text{Rest of Year PH} - \text{FMOH} - \text{POH} - \text{FOH})}{(\text{Rest of Year PH} - \text{FMOH} - \text{POH})}$$

Where

Rest of Year PH = hours during the Contract year falling in the months of October through May, provided that if Seller did not have a PSD Permit in effect during any portion of that period, then the number of such hours shall be multiplied by the fraction produced by dividing (i) the number of hours in the Contract Year that Seller has informed Buyer the facility may be operated at full load equivalent without exceeding applicable limits on the emission of PM-10 particulate by (ii) 8760

FMOH = Seller Force Majeure outage hours occurring during October through May

POH = planned outage hours (includes major maintenance hours and off-line water wash hours) occurring during October through May

FOH = forced outage hours occurring during October through May

C. Calculation of Guaranteed Equivalent Availability for a Contract Year

The Guaranteed Equivalent Availability for a Contract Year shall be determined from the following formula:

Guaranteed Equivalent Availability = (98% x Summer Factor) + (95% x Rest of Year Factor)

The Summer Factor and Rest of Year Factor for each Contract Year will be determined from the following table based upon the number of hours in such Contract Year that the facility is able to operate at full load equivalent without exceeding the applicable limits on the emission of PM-10 particulate:

Potential Hours of Operation in Contract Year	Summer Factor	Rest of Year Factor
1500 or less	90%	10%
1501 to 1600	80%	20%
1601 to 1700	70%	30%
1701 to 1800	60%	40%
1801 to 1900	50%	50%
1901 to 2000	40%	60%
more than 2000	33.3%	66.7%

D. Calculation of Yearly Equivalent Availability for a Contract Year

The Yearly Equivalent Availability for a Contract Year shall be determined from the following formula:

$$\text{Yearly Equivalent Availability} = (\text{Summer EA} \times \text{Summer Factor}) + (\text{Rest of Year EA} \times \text{Rest of Year Factor})$$

E. Availability Adjustment

Following the end of each Contract Year, Seller will calculate the Guaranteed Equivalent Availability and Yearly Equivalent Availability for that Contract Year. To the extent that the Yearly Equivalent Availability for that Contract Year differs from the Guaranteed Equivalent Availability, then an adjustment (the "Availability Adjustment") will be made to the Annual Capacity Charge for such Contract year (net of any Capacity Adjustment or Heat Rate Adjustment) with the amount of such adjustment to be determined by the following formula:

$$\text{Availability Adjustment} = [(\text{Yearly Equivalent Availability} \div \text{Guaranteed Equivalent Availability}) - 1] \times \text{Adjusted Capacity Charge}$$

The Adjusted Capacity Charge means the Annual Capacity Charge for that Contract Year net of any Capacity Adjustment or Heat Rate Adjustment applicable to that Contract Year.

F. Examples

Example 1: Guaranteed Equivalent Availability exceeds Yearly Equivalent Availability

This example assumes that the Seller does not have a PSD Permit and the facility may operate at full load equivalent for 2200 hours during the Contract Year without exceeding the applicable limitations on the emission of PM-10 particulate.

(A) Summer EA calculation:

Hours of potential operation = 2200
FMOH = zero
POH = zero
FOH = 24

$$\begin{aligned} \text{Summer PH} &= (122 \text{ days} \times 24 \text{ hours}) \times (2200 \div 8760) \\ &= 2928 \times .251 \\ &= 735 \end{aligned}$$

$$\begin{aligned} \text{Summer EA} &= (735 - 0 - 0 - 24) \div (735 - 0 - 0) \\ &= 711 \div 735 \\ &= 96.73\% \end{aligned}$$

(B) Rest of Year EA calculation:

Hours of potential operation = 2200
 FMOH = 10
 POH = 48
 FOH = 70

$$\begin{aligned} \text{Rest of Year PH} &= (243 \text{ days} \times 24 \text{ hours}) \times (2200 \div 8760) \\ &= 5832 \times .251 \\ &= 1464 \end{aligned}$$

$$\begin{aligned} \text{Rest of Year EA} &= (1464 - 10 - 48 - 70) \div (1464 - 10 - 48) \\ &= 1336 \div 1406 \\ &= 95.02\% \end{aligned}$$

(C) Guaranteed Equivalent Availability calculation:

$$\begin{aligned} \text{Guaranteed Equivalent Availability} &= (98\% \times .333) + (95\% \times .667) \\ &= 32.63\% + 63.37\% \\ &= 96\% \end{aligned}$$

(D) Yearly Equivalent Availability calculation:

$$\begin{aligned} \text{Yearly Equivalent Availability} &= (96.73\% \times .333) + (95.02\% \times .667) \\ &= 32.21\% + 63.38\% \\ &= 95.59\% \end{aligned}$$

(E) Availability Adjustment calculation:

$$\begin{aligned} \text{Capacity Adjustment} &= \$200,000 \\ \text{Heat Rate Adjustment} &= \text{zero} \\ \text{Adjusted Capacity Charge} &= (297,000 \times \$43.10) + \$200,000 \\ &= \$12,800,700 + \$200,000 \\ &= \$13,000,700 \end{aligned}$$

$$\begin{aligned} \text{Availability Adjustment} &= [(95.59\% \div 96\%) - 1] \times \$13,000,700 \\ &= [.9957 - 1] \times \$13,000,700 \\ &= -.0043 \times \$13,000,700 \\ &= -\$55,903 \end{aligned}$$

Example 2: Yearly Equivalent Availability exceeds Guaranteed Equivalent Availability

This example assumes that the Seller does not have a PSD Permit and the facility may operate at full load equivalent for only 1750 hours during the Contract Year without exceeding the applicable limitations on the emission of PM-10 particulate.

(A) Summer EA calculation:

Hours of potential operation = 1750
FMOH = zero
POH = zero
FOH = 4

Summer PH = $(122 \text{ days} \times 24 \text{ hours}) \times (1750 \div 8760)$
= $2928 \times .200$
= 586

Summer EA = $(586 - 0 - 0 - 4) \div (586 - 0 - 0)$
= $582 \div 586$
= 99.32%

(B) Rest of Year EA calculation:

Hours of potential operation = 1750
FMOH = zero
POH = 48
FOH = 50

Rest of Year PH = $(243 \text{ days} \times 24 \text{ hours}) \times (1750 \div 8760)$
= $5832 \times .200$
= 1166

Rest of Year EA = $(1166 - 0 - 48 - 50) \div (1166 - 0 - 48)$
= $1068 \div 1118$
= 95.53%

(C) Guaranteed Equivalent Availability calculation:

Guaranteed Equivalent Availability = $(98\% \times .6) + (95\% \times .4)$
= $58.80\% + 38.00$
= 96.80%

(D) Yearly Equivalent Availability calculation:

Yearly Equivalent Availability = $(99.32\% \times .6) + (95.53\% \times .4)$
= $59.59\% + 38.21\%$
= 97.80%

(E) Availability Adjustment calculation:

Capacity Adjustment = -\$150,000

Heat Rate Adjustment =		\$50,000
Adjusted Capacity Charge =		$(297,000 \times \$43.10) - \$150,000 + \$50,000$
	=	\$12,800,700 - \$100,000
	=	\$12,700,700
Availability Adjustment =		$[(97.80\% \div 96\%) - 1] \times \$12,700,700$
	=	$[1.0188 - 1] \times \$12,700,700$
	=	$.0188 \times \$12,700,700$
	=	\$238,773

Exhibit B

O&M Charge = $GEF + ((MFH1 \times A) - (MFH1 \times RHC)) + ((MFH2 \times A) - (MFH2 \times RHC))$

where

- *GEF = \$25,000.00 x 12 = \$300,000.00
- MFH1 = Factored Hours for Unit 1 of the facility during the Contract Year
- MFH2 = Factored Hours for Unit 2 of the facility during the Contract Year
- *RHC = \$258.00 x 0.40 = \$103.20
- FSR = the total Factored Hours for both units since the start of commercial operation divided by the total Factored Starts for both units since the start of commercial operation.

A = the value will be determined from the following table:

<u>FSR</u>	<u>A=</u>
<2	\$16156.00 - (\$6215.00 x FSR)
2 to <5	\$5261.00 - (\$767.33 x FSR)
5 to <10	\$2135.00 - (\$142.20 x FSR)
10 to <20	\$973.00 - (\$26.00 x FSR)
20 to <30	\$655.00 - (\$10.10 x FSR)
30 to <40	\$388.00 - (\$1.20 x FSR)
≥ 40	\$340.00

Factored Hours means for each combustion turbine unit of the facility the total number of hours that combustion turbine has operated since commercial operation whether or not the unit was synchronized and producing electricity (therefore, including the time between the initiation of a start and synchronization of the unit to the transmission provider's system and any time the unit is placed on a standby mode of full speed, no load), but excluding hours that the combustion turbine operated during optional capacity or heat rate tests requested by Seller.

Factored Starts = Normal Starts + (Emergency Starts x 20) + (Fast Load Events x 2) + (Full Load Trips x 8) + Part Load Trip Starts - Testing Starts, in each case since commercial operation

Normal Start is defined in Section 14.

Emergency Start is defined in Section 14.

Fast Load Event = an occasion where the loading of a unit is increased at a rate greater than 8.33% per minute of the unit's full load rating at ambient conditions at the time

Full Load Trip = a unit trip when the unit output is at or above 80% of the unit's full load rating at ambient conditions at the time, but not including any unit trip caused by unit equipment malfunction or operator error

Part Load Trip = a unit trip when the unit output is between full speed, no load and 80% of the unit's full load rating at ambient conditions at the time, but not including any unit trip caused by unit equipment malfunction or operator error

Part Load Trip Starts = the sum of the FS Equivalents determined for each Part Load Trip

FS Equivalents for a Part Load Trip shall be calculated using the following formula:

$$\text{FS Equivalents} = (4.6429 \times \text{LF} \times \text{LF}) + (3.7857 \times \text{LF}) + 1.9914$$

where LF equals the load factor of the unit (stated as a decimal) at the time the Part Load Trip occurred

Testing Start = a Normal Start performed as part of an optional test of capacity or heat rate requested by Seller