The Lockport Project has secured gas supply from the combination of two domestic and one Canadian suppliers. These gas supply contracts were the first in the industry that utilized fixed, predetermined pricing for the duration of a 15 year contract term. Natural gas is transported to the project site via the Tennessee Gas Pipeline Company ("TGPL") under a set of 15 year firm transportation agreements. The Canadian supplies are delivered via the NOVA Pipeline, TransCanada Pipeline and TGPL.

The project was engineered and constructed by Chas. T. Main, Engineers & Constructors, a subsidiary of the Parsons Corporation, under a fixed price date certain engineering, procurement and construction contract. The project is operated and maintained by North American Energy Services Company.

Chase Manhattan Bank was the construction and term lender for the project. LS Power negotiated all project contracts and agreements, obtained all federal, state and local permits and approvals, participated in and coordinated the debt placement process of the project. The Lockport Project was the first large cogeneration project developed by LS Power as an independent entity.

BORGER PROJECT

In February of 1997, a joint proposal offered by the partnership of LS Power and Quixx Corporation, then a subsidiary of Southwestern Public Service Company (SPS), was selected via a competitive solicitation process to serve SPS's future power supply needs. The project is located at the Phillips Petroleum Refinery near Borger, Texas and will provide approximately 216 MW of electrical capacity to SPS and process steam to the refinery. The project configuration will utilize two natural gas fueled combustion turbines to produce both the electricity and process steam. The project was financed via a public bond offering arranged by Morgan Stanley Dean Witter and ABN-AMRO Chicago Corporation. Construction commenced in October, 1997 and full commercial operation is scheduled to occur in early 1999. Gas will be supplied to the project by GPM Gas Corporation, a subsidiary of Phillips Petroleum Company.

MUSTANG STATION PROJECT

In August of 1996, Golden Spread Electric Cooperative of Amarillo, Texas selected a joint proposal offered by the partnership of LS Power and Quixx Corporation to serve Golden Spread's power supply needs. The project is being developed by the partnership and once operational, fifty percent of the project will be sold to Golden Spread. The output from the partnership share of the project will be sold under a long term power purchase agreement with Golden Spread. Operational decisions will be handled jointly between the partnership and Golden Spread with the day-to-day operational activities managed by the partnership. LS Power was the lead partner responsible for many of the development activities associated with the project including permitting, procurement of water rights, negotiation of major contracts and arranging project financing. LS Power is currently responsible for managing construction of the project. Project financing was completed in January 1998 and was arranged and underwritten jointly by Societe Generale and CoBank, ACB. Natural gas will be provided to the project by a combination of El Paso Energy Marketing Company and Aquila Energy Marketing Corporation.

The Mustang Project is a 500 megawatt combined cycle facility located in Denver City, Texas being constructed in a phased approach. The project will begin operation in simple cycle phase in late spring 1999 and will be converted to combined cycle operation in late 1999. This project was selected as the result of a highly competitive request for proposal process initiated by Golden Spread in 1994, which included a similar project that would have been entirely developed by Golden Spread. The partnership's proposal, however, provided Golden Spread with the optimum combination of economics, risk mitigation and operational flexibility.

BATESVILLE GENERATION PROJECT

In February, 1996, LS Power entered into an option purchase agreement with Tennessee Valley Authority (TVA) for the supply of 750 megawatts of capacity and associated energy. This agreement was the first of its kind for TVA and was the result of a request for proposals in which 138 bidders responded. In late 1997, due to changed market conditions between the execution of the option agreement and the strike date, TVA elected not to exercise its option.

In December, 1998 LS Power issued a reverse RFP to power marketers and other potential power purchasers in the region. As a result of that process, LS Power recently executed two power purchase agreements for the sale of 800 megawatts of capacity and energy under the terms of a tolling arrangement. Under this arrangement, LS Power guarantees completion, output, availability and efficiency performance, and, in exchange for fuel supplied by the power purchasers, the power purchasers receive net electrical output from the facility.

The project, located in Batesville, Mississippi, has direct access to both the high voltage transmission systems of the Tennessee Valley Authority and Entergy and will interconnect with multiple interstate natural gas pipelines. Construction is scheduled to commence in early summer, 1998, with commercial operation by June, 2000.

FAX COVER SHEET

Basin Electric Power Cooperative
1717 East Interstate Avenue
Bismarck, ND 58501-0564
Phone: (701) 223-0441

☐ Fax: (701) 224-5315 (Comm. & Govern. Relations)
☐ Fax: (701) 224-5336
☐ Fax: (701) 224-5343 (Office of General Counsel)
☐ Fax: (701) 224-5314 (ObjectFax)
☐ Fax: (701) 224-5332 (Marketing & Member Services)
☐ Fax: (701) 224-5394 (Procurement)
☐ Fax: (701) 224-5357 (Financial Services)
☐ Fax: (701) 224-5376 (Basin Travel)
☐ Fax: (701) 255-5143 (Management Information Serv.)

To: Kiah Harris

Company Name: Burns & McDonnell

Fax Number: 816 333 3690

From: Tom Christensen

Department:

☒ For Your Information ☐ For Your Comments Please call Ext. ______

Additional Information:

Original to follow? ☐ Yes ☐ No

By: ☐ Regular Mail ☐ Overnight ☐ Other ______

Number of pages (including cover): 34

Date sent: ______ Time sent: ______

If there are any problems receiving this transmission please call: (701) 223-0441, Ext. 2527; Ext. 2364 (Procurement); Ext. 2416 (Basin Travel); Ext. 2669 (Office of General Counsel); Ext. 2212 (Marketing & Member Services); Ext. 2307 (Comm. & Govern. Relations); Ext. 2652 (Financial Services) or Ext. 3938 (Management Information Services).

BEPC 00114 8/94

BASIN ELECTRIC
POWER COOPERATIVE

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58501-0564
PHONE: 701/223-0441
FAX: 701/224-5336

July 2, 1998

CONFIDENTIAL

Mr. Kiah Harris
Manager, Business Analysis and Consulting
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Dear Mr. Harris:

Basin Electric is pleased to respond to your May 22, 1998, request for power supply proposals for Missouri Public Service (MPS). With this proposal, Basin Electric is offering annual MAPP Service Schedule A capacity to MPS. Our proposal covers the June 1, 2000 through May 31, 2004 period, but Basin Electric would consider a shorter or possibly longer duration. Basin Electric's proposal is for up to 100 MW, with the major details of the proposal listed on the attached sheets.

Please contact Tom Christensen with any questions. Due to the number of other potential capacity commitments, Basin Electric reserves the right to withdraw this offer at any time.

Sincerely,

Robert L. McPhail
General Manager

tsc/ms
ATTACHMENT
cc: David Raatz
Tom Christensen

Schedule A Transaction
Annual Participation Power

CONFIDENTIAL

Governing Agreement:	The Mid-Continent Area Power Pool (MAPP) Agreement, as amended, or alternatively a separate two-party agreement could be used.
Transaction Type:	MAPP Service Schedule A: Participation Power Interchange Service, or a mutually agreed to alternate service schedule.
Delivering Party:	Basin Electric Power Cooperative (BEPC)
Receiving Party:	Missouri Public Service (MPS)
Term:	June 1, 2000 through May 31, 2004
Contract Amount:	Up to 100 MW
Contingent on Transmission Availability:	This Agreement would be contingent upon ability to secure Firm Transmission Service.
Power Demand Charge:	<u>Year</u> <u>Demand Charge</u> <u>Year</u> <u>Demand Charge</u> 2000 $12,600/MW-mo 2003 $14,100/MW-mo 2001 $13,100/MW-mo 2004 $14,600/MW-mo 2002 $13,600/MW-mo Basin Electric would require a provision for adjusting the demand charge upward to cover the cost of any new or increased tax or emission requirements.
Transmission Demand Charge:	<u>Year</u> <u>Demand Charge</u> <u>Year</u> <u>Demand Charge</u> 2000 $2,530/MW-mo 2003 $2,530/MW-mo 2001 $2,530/MW-mo 2004 $2,530/MW-mo 2002 $2,530/MW-mo The price listed is the estimated firm point-to-point transmission rate which could be used to deliver power from BEPC to MPS under a MAPP long-term tariff. This cost will vary based on the actual transmission costs incurred.
Energy Charge:	<u>Year</u> <u>Energy Charge</u> <u>Year</u> <u>Energy Charge</u> 2000 $12.70/MWh 2003 $13.90/MWh 2001 $13.10/MWh 2004 $14.30/MWh 2002 $13.50/MWh Basin Electric would require the provision for adjusting the energy charge upward to cover the cost of any new or increased tax or emission requirements.

 CONFIDENTIAL

System Contingent Capacity:	The energy supply shall be contingent upon the availability of BEPC's North Dakota coal-fired generation. If a BEPC coal-fired generation resource is taken off-line or substantially curtailed due to equipment failure or required maintenance, BEPC shall have the right but not the duty to interrupt deliveries under an agreement upon notice. BEPC will consider alternate curtailment procedures which would allow BEPC to continue energy deliveries to MPS with the understanding that MAPP emergency procedures will be adhered to, and with consideration of negotiated pricing during those times that BEPC resources are limited.
Availability:	Participation Power provided under this Agreement is intended to be available at all times, subject to unit availability, line loading limitation of the transmission systems involved and all factors generally considered to be covered by Force Majeure. However, under no circumstances will BEPC native firm loads be interrupted to maintain energy deliveries under this agreement.
Scheduling:	Basin Electric would require a minimum schedule commitment equal to 50% of the contract amount and would reserve the right to limit the hourly schedule change based upon the ramping capability of BEPC's North Dakota coal-fired generation.
Capacity Factor:	Basin Electric would require a 70% minimum monthly load factor and a maximum monthly load factor of 90%. If emission credits are supplied to BEPC, the load factor limit could be raised.
Delivery Point:	The energy shall be delivered through the use of the MAPP long-term tariff to MPS's transmission system. Therefore, the delivery point consistent with the use of MAPP long-term tariff transmission is the point(s) of interconnection between MAPP RTC member(s) transmission system(s) and MPS's transmission system.
Energy Losses:	BEPC shall be responsible for all energy losses associated with delivering this power to the MPS's transmission system. MPS shall be responsible for losses on the MPS transmission system.
Contact Person:	Tom Christensen Phone: 701/223-0441, ext. 2242 E-Mail: chrsn@bepc.mapp.org

Aquila Power
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
816-936-8712
Fax: 816-936-8775
msherman@utilicorp.com

AQUILA ENERGY

July 6, 1998

Max A. Sherman
Director
Power Marketing

Mr. Kiah Harris
Manager - Business Analysis and Consulting
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114

Subject: Request for Proposals for Resource Specific Capacity and Energy for Missouri Public Service

Dear Mr. Harris:

Aquila Power Corporation, a power marketing subsidiary of Aquila Energy, is pleased to respond to Missouri Public Service Company's RFP for resource specific capacity and energy. We are offering capacity from a generating project to be constructed in Mississippi with a commercial operation date of June 1, 2000. We are offering terms of one to four years, with buyout provisions which maximize the flexibility available to MPS. While the project is a combined cycle project, we have structured our proposal as a peaking capacity proposal to meet what we understand to be MPS' capacity requirements.

We believe our prices are competitive and will be economically attractive to MPS. Estimated transmission costs are included in the pricing, as separate components and alternatives priced separately. Actual transmission costs will be the basis for billing.

Because this proposal contains proprietary information relating to our specific generating unit, Aquila Power requests that Burns and McDonnell treat this proposal as confidential in accordance with the confidentiality agreement between Aquila and Burns and McDonnell.

Our proposal shall remain valid for ninety days, unless otherwise extended by Aquila Power. However, pricing will necessarily be subject to revision due to changing market conditions until consummation of a contract between the parties.

We thank you for the opportunity to submit this proposal. Should you have any questions concerning this submittal, please do not hesitate to contact the undersigned. We look forward to meeting Missouri Public Service Company's requirements.

Very truly yours,

Max Sherman

Max Sherman
Director, Power Marketing

Enclosure

cc: David Stevenson
Jeff James

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AQUILA POWER CORPORATION PROPOSAL

TO

MISSOURI PUBLIC SERVICE

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EXECUTIVE SUMMARY

Aquila Power is offering peaking capacity to Missouri Public Service from a generating unit to be built in Batesville, Mississippi, under terms and conditions which are summarized as follows:

- Term: Various terms are offered from June 1, 2000 through May 31, 2004, with buyout options for the last 2 contract years.
- Type of Service: Unit power with a 93% minimum guaranteed annual equivalent availability.
- Designated Unit: A nominal 267 MW combined cycle generating unit to be constructed by LS Power LLC at an industrial park at the Entergy/TVA border in Batesville, Mississippi. The unit is fully permitted. Initial financing and breaking ground to start construction is expected to start in late July 1998. Aquila Power has executed a contract to purchase the capacity and the right to toll energy from the unit for a term well beyond the period requested by the subject RFP.
- Capacity price: We have priced the capacity at the site, and provided a number of transmission options to move the power and associated energy to MPS' system. The least cost firm transmission path from the project to MPS, across Entergy and Ameren, is presently ~$2.00/kW-month. The capacity prices under various options are shown below:

  Option 1
  $10,000/MW-month from June 1, 2000 through September 30, 2000 (100 MW)
  $750/MW-month from October 1, 2000 through May 31, 2001 (75 MW)

  Option 2 (75 MW)
  $3,833.33/MW-month from June 1, 2000 through May 31, 2001

  Option 3 (Up to 100 MW)
  $4,000/MW-month from June 1, 2001 through May 31, 2002
  $4,500/MW-month from June 1, 2002 through May 31, 2003
  $5,000/MW-month from June 1, 2003 through May 31, 2004

  Buyout option cost for termination during the contract year of June 1, 2002 through May 31, 2003 is $10,000/MW. Buyout option cost for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004) is $20,000/MW.

- Energy Price: $100.00/MWh plus the actual cost of transmission losses and/or ancillary services for delivery of the power to MPS. At present, the estimated cost of transmission losses across Entergy and Ameren (the least cost firm path) is $3.41/MWh.

- Delivery Points: APC will deliver energy to MPS' interconnections with the Eastern interconnection. This includes MPS' direct interconnections with Ameren, Associated Electric Cooperative, Inc., Kansas City Power & Light, and Western Resources.

- Transmission: Transmission charges will be billed to MPS at Aqulia's actual cost. Aquila has identified transmission across Entergy and Ameren as the least cost firm transmission path from the Batesville project which meets the RFP requirements. Present prices for firm transmission on this path range from ~$2000/MW-month ~$2162/MW-month, depending on whether annual or monthly firm service is purchased from Entergy. However, Aquila believes that it may be possible for MPS to relax the requirement for firm service to MPS <u>if</u> the capacity were to be delivered across Entergy to the Southwest Power Pool. Aquila has therefore shown transmission pricing in Tab 7 for a variety of alternative scenarios for consideration by MPS.

- Market Conditions: Pricing is necessarily subject to revision due to changing market conditions, up to execution of a contract between the parties.

DESIGNATED GENERATING UNIT

The designated generating unit is a nominal 267 MW combined cycle generating unit to be constructed by LS Power LLC at an industrial park at the Entergy/TVA border in Batesville, Mississippi. The unit is one of three units to be constructed on the site, with a nominal total capacity rating of 800 MW. Aquila Power has executed a contract to purchase the capacity and the right to toll energy from one unit for a term well beyond the period requested by MPS' Request for Proposals. The project will interconnect with both the Tennessee Valley Authority and the Entergy transmission systems at 161 kV. Aquila has been advised that the EPC contractor and generating equipment vendor have been selected. Because these vendor selections have not been made public, Aquila is not able to disclose who these entities are at this time.

LS Power LLC has advised Aquila Power that the project is fully permitted, and provided a copy of the major permits (which are listed below). The project schedule calls for initial financing and breaking ground to start construction in late July 1998, in order to meet a June 1, 2000 in-service date specified in Aquila's power purchase agreement with LS Power.

<u>Major Permits and Approvals for Batesville Project</u>

- Public Service Commission of Mississippi Certificate of Public Convenience and Necessity, Docket No. 97-UA-513, dated December 12, 1997
- State of Mississippi Air Pollution Control Permit No. 2100-00054, dated November 25, 1997 (both permission to construct and permission to operate)
- National Pollutant Discharge Elimination System (NPDES) Permit No. MS0052931, dated December 12, 1997
- Mississippi Permit to Divert or Withdraw for Beneficial Use the Public Waters, Permit No. MS-SW-02744, dated November 25, 1997.
- Federal Energy Regulatory Commission Certification of Exempt Wholesale Generator Status, Docket No. EG98-59-000, dated April 28, 1998.
- U.S. Army Corps of Engineers Nationwide/General Permit Nos. NW07, NW12, NW25, NW26 and GP22, issued December 4, 1997.
- City of Batesville, MS Confirmation of Appropriate Zoning, dated April 24, 1997.

Copies of these permits can be provided upon request.

TERM

Various terms are offered to be as flexible as possible in meeting MPS' requirements:

<u>Option 1</u>
June 1, 2000 through September 30, 2000 (100 MW)
October 1, 2000 through May 31, 2001 (75 MW)
(Aquila is willing to discuss each Option 1 period separately)

<u>Option 2 (75 MW)</u>
June 1, 2000 through May 31, 2001

<u>Option 3 (Up to 100 MW)</u>
June 1, 2001 through May 31, 2002
June 1, 2002 through May 31, 2003
June 1, 2003 through May 31, 2004

Buyout options are offered for termination during the last two contract years of Option 3.

The following quantities of capacity are offered, using the Options described in Tab 4, above:

Option 1:	100 MW for summer 2000 (June 1, 2000 through September 30, 2000) 75 MW for non-summer months (October 1, 2000 through May 31, 2001)
Option 2:	75 MW June 1, 2000 through May 31, 2001
Option 3:	Up to 100 MW for the last three (3) contract years (June 1, 2001 through May 31, 2004)

Options 1 and 2 are mutually exclusive. Aquila would be willing to consider selling the summer and non-summer months in Option 1 separately.

Option 3 may be selected by MPS, if it desires, only if it has agreed to purchase capacity under Options 1 or 2.

CAPACITY PRICE

We have priced the capacity at the site, and provided a number of transmission options to move the power and associated energy to MPS' system at MPS' cost. The least cost firm transmission path from the project to MPS, across Entergy and Ameren, is presently ~$2.00/kW-month. The capacity prices under various options are shown below:

Option 1
$10,000/MW-month from June 1, 2000 through September 30, 2000 (100 MW)
$750/MW-month from October 1, 2000 through May 31, 2001 (75 MW)

Option 2 (75 MW)
$3,833.33/MW-month from June 1, 2000 through May 31, 2001

Option 3 (Up to 100 MW)
$4,000/MW-month from June 1, 2001 through May 31, 2002
$4,500/MW-month from June 1, 2002 through May 31, 2003
$5,000/MW-month from June 1, 2003 through May 31, 2004

Buyout option costs
$10,000/MW for termination during the contract year of June 1, 2002 through May 31, 2003.
$20,000/MW for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004).

The buyout option can be exercised with no less than 12 months' prior written notice by MPS to Aquila Power.

TRANSMISSION SERVICE

Transmission charges will be billed to MPS at Aqulia's actual cost. Aquila has identified transmission across Entergy and Ameren as the least cost firm transmission path from the Batesville project which meets the RFP requirements. Present prices for firm transmission on this path range from ~$2000/MW-month ~$2162/MW-month, depending on whether annual or monthly firm service is purchased from Entergy (refer to Table 1, below). However, Aquila believes that it may be possible for MPS to relax the requirement for firm service to MPS if the capacity were to be delivered across Entergy to the Southwest Power Pool (SPP). This is because capacity delivered to the SPP is expected to be counted by the SPP in order to meet a member utility's reserve capacity obligations (per an Aquila discussion with SPP staff). While the SPP will have a requirement effective October 1, 1998 that firm transmission for purchased capacity is required, there is at present no penalty imposed if this requirement is not met. In addition, the issue of grandfathering capacity transactions which existed before the October 1, 1998 effective date, analagous to grandfathering transmission service transactions entered into before the effective date of the SPP regional transmission tariff, to Aquila's knowledge has not been addressed. There may therefore be an opportunity to grandfather the associated transmission arrangements. For these reasons, Aquila has shown present firm transmission prices in Table 1, below for alternative scenarios for consideration by MPS.

Table 1
Transmission Scenarios and Present Prices
(For capacity from Aquila's designated generating unit in Batesville, MS)

Path	Utility #1 and cost	Utility #2 and cost	Total ($/MW-mo)
Project-Entergy -Ameren-MPS	Entergy $999.10/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (annual firm service)	Ameren $11974.52 per MW-yr ($0.21/MWh losses) (annual firm service)	$1996.98
Project-Entergy -Ameren-MPS	Entergy $1163.9/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (monthly firm service)	Ameren $997.86 per MW-mo. ($0.21/MWh losses) (monthly firm service)	$2161.76
Project-Entergy -AECI-MPS	Entergy $999.10/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (annual firm service)	AECI $21192.87 per MW-yr (+$1.20/MWh losses & anc. svcs.) (annual firm service)	$2765.17

Project-Entergy -AECI-MPS	Entergy $1163.9/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (monthly firm service)	AECI $1766.08 per MW-mo. (+$1.20/MWh losses & anc. svcs.) (monthly firm service)	$2929.98
Project-TVA -Ameren-MPS	TVA $2041/MW-mo. (+. 3% losses) (monthly firm service)	Ameren $997.86 per MW-mo. ($0.21/MWh losses) (monthly firm service)	$3038.86

ENERGY PRICE

The offered energy price is $100.00/MWh plus the actual cost of transmission losses and/or ancillary services for delivery of the power to MPS. At present, the estimated cost of transmission losses across Entergy and Ameren (the least cost firm path) is $3.41/MWh.

OPERATION AND MAINTENANCE

Operation

LS Power will be responsible for operation of the designated generating unit. Aquila Power will be responsible for the fuel supply. The unit will be operated and maintained in accordance with equipment manufacturer recommendations.

Maintenance

LS Power will be responsible for maintaining the unit in accordance with equipment manufacturer recommendations. Aquila's contract with LS Power contains strong incentives for LS Power to schedule maintenance during the low load months in the Spring and Fall, and to minimize the annual scheduled maintenance hours subject to manufacturer's recommendations. Scheduled maintenance is not allowed during the period from June 15 to September 15.

The maintenance schedule for the designated unit is determined annually. The criteria and contract conditions for determining the maintenance schedule are attached. Aquila requests this information be treated as confidential.

``Section 5.4 Scheduled Maintenance.

(a) At least thirty (30) Days prior to the Commercial Operation Date and thereafter prior to June 1 of each subsequent calendar year, Purchaser shall provide to Seller a non-binding proposed schedule of its projected Dispatch for, in the case of the first such schedule, the nineteen (19)-Month period beginning on the Commercial Operation Date, and thereafter for the twelve (12)-Month period beginning on January 1st of the following calendar year.

Based on Purchaser's projected Dispatch schedule and subject to Section 5.4(b), Seller shall provide Purchaser with its proposed maintenance schedule for such twelve (12)-Month period within ten (10) Days following receipt of Purchaser's projected Dispatch schedule. Purchaser and Seller shall agree on the expected timing of the Scheduled Maintenance Outages for such twelve (12)-Month period with no Scheduled Maintenance Outages to occur during the period from June 15 to September 15. Scheduled Maintenance Outages may be taken in any number of non-contiguous periods, provided number of Scheduled Maintenance Hours does not exceed the amounts specified in Section 5.4(b). Seller shall coordinate all Scheduled Maintenance Outages with Purchaser by giving Purchaser written notice at least ten (10) Days prior to a Scheduled Maintenance Outage such notice to include the scheduled start date, time, and duration of such Scheduled Maintenance Outage. Unless otherwise agreed by the Parties, acting reasonably, the start date of a Scheduled Maintenance Outage shall occur within one (1) Day of the date the Parties agreed to schedule such Scheduled Maintenance Outage as set forth above. To the extent the start of a Scheduled Maintenance Outage deviates by more than one (1) Day from the schedule that had been agreed to, such deviation shall count towards the 120 hours available to Seller pursuant to Section 5.4(c).

(b) Scheduled Maintenance Outages shall be determined in accordance with manufacturer's recommendations in accordance with formulae provided by relevant equipment manufacturers. The number of Scheduled Maintenance Hours shall be further limited to 336 hours each calendar year in which a minor inspection (e.g. combustion inspection) occurs, 480 hours each calendar year in which a hot gas path inspection occurs, and 840 hours each calendar year in which a Major Inspection occurs. Subject to Purchaser not exceeding 200 Start-Ups per year, the Scheduled Maintenance Outage frequency shall be no greater than annually for a minor inspection, every three (3) years for a hot gas path inspection, and every five (5) years for a Major Inspection; *provided, however,* that such maintenance frequencies shall be further subject to changes in the manufacturer's recommendations. To the extent Purchaser exceeds 200 Start-Ups in a calendar year, and to the extent manufacturer's recommendations require a greater frequency of maintenance than that described herein, the frequency of such maintenance shall be adjusted in accordance with such manufacturer's recommendations.

(c) If required in accordance with Prudent Industry Practices or manufacturers' recommendations, Seller may utilize up to 120 Scheduled Maintenance Hours per calendar year to perform maintenance repairs at a different time than designated pursuant to Section 5.4(a). Seller shall provide Purchaser with no less than two (2) Business Days prior notice of such requirement; provided that Seller shall not be entitled to make such re-allocation of Scheduled Maintenance Hours during the period from June 15 through September 15 without the prior consent of Purchaser. Seller shall use its best efforts to schedule such Scheduled Maintenance Outages in a manner that allows Scheduled Maintenance Outages of less than eight (8) *contiguous hours to occur during Off-Peak Hours.''*

AVAILABILITY

The minimum guaranteed annual equivalent availability, once the unit achieves commercial operation, is 93%.

SCHEDULING

Scheduling of power and energy from the designated generating unit will be by MPS to Aquila by 8:30 a.m the previous business day. This deadline is needed to enable Aquila to nominate natural gas for the unit. Schedules shall be submitted by MPS to Aquila Power by facsimile or telephoned instruction to Aquila's designated representative for this transaction. The minimum schedule block is 25 MW for any hour the power is scheduled. The minimum schedule duration is eight (8) consecutive hours. MPS shall also reimburse Aquila for a pro-rata share of start-up costs; for a 267 MW generating unit approximately 3000 MCf of natural gas is required for start-up.

When Aquila is serving MPS from the generating unit, procedures will need to be established to cover the generating unit ramp rates from synchronization to minimum load, and between minimum and full load. This may mean that changes in scheduled hourly deliveries requested by MPS may need to be accommodated over more time than the ten minute ramp across the top of the hour which is normal practice in SPP. In such event, MPS and Aquila will develop procedures, working with transmission providers, to allow longer ramp times if required to facilitate desired schedule changes.

DELIVERY POINTS

- APC will deliver energy to MPS' interconnections with the Eastern interconnection. This includes MPS' direct interconnections with Ameren, Associated Electric Cooperative, Inc., Kansas City Power & Light, and Western Resources.

BUYOUT OPTIONS

Buyout option costs are as follows:

$10,000/MW for termination during the contract year of June 1, 2002 through May 31, 2003.

$20,000/MW for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004).

The buyout option can be exercised with no less than 12 months' prior written notice by MPS to Aquila Power.

CONDITIONS PRECEDENT

Any agreement entered into hereunder will have the conditions precedent to effectiveness of the agreement that:

1. The Project will have financial closing occur by August 15, 1998, unless such condition is waived or extended by Aquila Power.
2. The effectiveness of the agreement shall also be subject to receipt of all required regulatory approvals, including for Aquila, the Federal Energy Regulatory Commission, and including for MPS the Missouri Public Service Commission.
3. Completion of construction and commissioning of the unit as scheduled.
4. Acquisition of firm transmission service as directed by Missouri Public Service.

10700 East 350 Highway
Kansas City, Missouri 64138

September 14, 1998

UTILICORP UNITED
ENERGYONE

Mr. Mike Proctor
Assistant Manager
Federal/State Projects
Missouri Public Service Commission
310 West High Street
Jefferson City, MO 65101

Mr. Ryan Kind
Chief Utility Economist
Office of Public Counsel
Harry S. Truman Bldg., Ste. 250
PO Box 7800
Jefferson City MO 65102

RE: **Missouri Public Service May, 1998 Request for Proposal - Proposal Revisions**

Gentlemen:

On August 25, 1998, MPS requested that all responders to the above referenced RFP provide an indication of continued interest along with any changes in their proposed pricing and/or other terms and conditions.

Responses have been received from all but one of the firms that originally submitted proposals. A brief summary of the responses received to date is attached. Note that only NP Power made significant changes to its pricing structure.

MPS is currently negotiating with New Century Energies and Basin Electric Cooperative as well as Sunflower Electric Cooperative in an attempt to secure adequate supplies of capacity and energy for the 12 months beginning June 1, 2000.

For the post 2000 period, MPS will evaluate the revised proposal from NP Power and perform the gas price sensitivities requested by staff.

Please call me at 816-936-8639, if you have any questions or need additional information.

Sincerely,

Frank A. DeBacker

Frank A. DeBacker

Attachment

cc: Gary Clemens
John McKinney

Missouri Public Service
1998 Request for Proposals

Proposal Revision Summary

Aquila Power	No Response to date.
Basin Electric	Continued interest, no change in price. MPS is currently negotiating with Basin for MPS' year 2000 requirements.
CP&L	Continued interest. Delayed in service date to June, 2001 from June, 2000 and increased prices by 15%.
LS Power	Withdrew proposal.
New Century	Continued interest, revised price slightly downward for 2000. MPS is currently negotiating with New Century for MPS' year 2000 requirements.
NORAM	Continued interest with no change in pricing. Emphasized that their proposal was only "indicative" and that prices are for illustration only.
NP Energy	Continued interest with extensive price revisions. Changes include an increase in capacity from $2,500 to $4,000 per MW-mo. and a decrease in energy pricing from 'market rates' to a pricing structure based on gas prices and unit heat rates. MPS is currently evaluating the revised proposal.
Southern Co.	Continued interest with no change in pricing. Emphasized that their proposal was only "indicative" and that prices are for illustration only.

10700 East 350 Highway
Kansas City, Missouri 64138

September 18, 1998

UTILICORP UNITED
ENERGYONE

Mr. Mike Proctor
Assistant Manager
Federal/State Projects
Missouri Public Service Commission
310 West High Street
Jefferson City, MO 65101

Mr. Ryan Kind
Chief Utility Economist
Office of Public Counsel
Harry S. Truman Bldg., Ste. 250
PO Box 7800
Jefferson City MO 65102

Gentlemen:

Per my voicemail message from Ryan Kind of today, please find enclosed the letter issued to all bidders soliciting updates to their proposals and their responses to that request.

Please call me at 816-936-8639, if you have any questions or need additional information.

Sincerely,

Frank A. DeBacker

Frank A. DeBacker

Attachment

cc: Gary Clemens
John McKinney

August 25, 1998

RE: Power Supply RFP for Missouri Public Service issued by UtiliCorp United Inc.

Dear :

Your firm's proposal was one of eight received by UtiliCorp in response to the above referenced RFP. UtiliCorp is now in the final phase of its analysis of the proposals and will complete that analysis by mid-September.

During the last few months, the wholesale power market in the US has gone through a period of extreme volatility and high prices resulting in severe financial consequences for a number of firms and an increase in the perceived value of generation equipment. In light of these events, UtiliCorp desires to confirm the viability of the proposals under consideration.

The purpose of this letter is to:

1) Determine if your firm continues to be interested in providing power supply resources to Missouri Public Service (MPS).
2) Provide an opportunity for interested bidders to update or otherwise modify their original proposal.

Please respond to this letter if your firm continues to have an interest in providing power supply resources to MPS. Please include any pricing changes and/or other modifications to your firm's original proposal in your response. Finally, please include an expiration date for the proposal.

In order for your firm's proposal to continue to be considered, a written response to this letter must be received by the undersigned no later than 5:00 PM; September 4, 1998.

Sincerely yours,

Frank A. DeBacker
Phone: (816) 936-8639
Fax: (816) 936-8695
Email: fdebacke2@utilicorp.com

NP Energy

NP Energy Inc.
3650 National City Tower
101 South Fifth Street
Louisville, Kentucky 40202

502.560.5300
502.560.5310 Fax

September 4, 1998

Frank A. DeBacker
Utilicorp
10700 East 350 Highway
Kansas City, Missouri 64138

Dear Frank:

In response to your letter dated August 25, 1998, NP Energy would like to submit the following proposal as a replacement for our original proposal. This proposal, which is detailed in the attached term sheet, is summarized here. NPE sells 200-300 MWs of capacity to MPS for a 5-year term. MPS has the option to call energy at a heat rate of 10,600 btu/kWh. The energy is unit firm with a guaranteed equivalent availability of 90%, and no less than 98% in the summer months.

This proposal is based upon NPE or a qualified developer building generation. While we are confident in our analysis and the underlying fundamentals, we would like to stress that this proposal is contingent upon numerous site specific and equipment specific factors. If this proposal is of interest to you, we are prepared to quickly finalize our offer.

The consummation of this transaction is subject to the successful negotiation, approval and execution of a mutually agreeable definitive agreement, and NPE Board of Directors approval. As the market is constantly changing, NPE will advise you of any market fluctuations which may affect NPE's pricing.

Please feel free to call me with any questions at (502)560-5366. I look forward to talking with you. I will be out of the office the week of September 7th, but my colleague Terry Naulty will be available should you have any questions during that time. He can be reached at (502)560-5361.

Regards,

Sherry M. Perchik
Regional Marketing Director

Attachments

CONFIDENTIAL

Capacity & Optional Peaking Energy Proposal
Prepared for Missouri Public Service by NP Energy Inc.
September 4, 1998

TIME PERIOD:

Start Date: June 1, 2001
End Date: May 31, 2006

FIXED CAPACITY PRICE:

SPP Accredited Capacity: Yes
Quantity: 200 – 300 MWs
Price: $4.00/kw-month capacity payment; escalated at 2.5% per year

ENERGY PRICE (applies for all hours of term):

MPS will have the option to call energy at $1.00/MWh (escalates at 2%) plus the product of a heat rate of 10,600 btu/kWh (at most efficient point) times the fuel cost. MPS can supply the gas, or NPE can supply the gas. If NPE supplies the gas, MPS will pay either a) a mutually acceptable index, adjusted for delivery to the facility, if the power is scheduled by 10:00 AM CPT, or otherwise b) the actual gas cost for energy scheduled after 10:00 AM CPT and up until 1 hour prior to hour of flow

START/STOP COSTS

No charge will be assessed for the first 50 starts/stops per year. A $2,500 charge per start will be assessed thereafter

DELIVERY POINT/TRANSMISSION:

The facility will be connected to the MPS transmission system, and will deliver energy at transmission level voltages. NPE and MPS will work cooperatively to optimally site the facility

NATURE OF SERVICE:

Unit Firm

ENERGY AVAILABILITY:

Annual equivalent availability will be guaranteed to be no less than 90%, and no less than 98% (with 47% of MWh in on-peak hours) in the summer months of June – September

NORAM

ENERGY SERVICES

POWER MARKETING DEPARTMENT

1111 LOUISIANA STREET, 8th FLOOR
HOUSTON, TX 77002

P.O. BOX 4455
HOUSTON, TX 77210-4455

MEMO

DATE: 9/4/98

TO: Frank DeBacker

CO.: UtiliCorp

FROM: Terry D. Lane (P) 713.207.5117 (F) 713.207.9626
(E-mail) tdlane@noram.com

Thanks for your letter dated 8/25/98 regarding the Power Supply RFP for MPS. Houston Industries is definitely interested in being a part of the RFP process. At this time, we will leave in place the proposal we originally submitted. We may be interested in supplying more than 100 MWs. As I mentioned in follow-up correspondence, we are anticipating supplying from a facility to be constructed in Wood River, IL. We are also interested in discussing the possibility of building in MPS territory to serve the entire RFP requirement. Houston Industries has committed to building or acquiring generation assets in strategic locations. Supplying the MWs needed in this RFP fits well in that strategy.

We are hopeful that we will make whatever short list you arrive at and that we can begin detailed discussions soon. And thanks again for the opportunity to respond. I'll look forward to hearing from you.

**BASIN ELECTRIC
POWER COOPERATIVE**

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58501-0564
PHONE: 701/223-0441
FAX: 701/224-5336

August 26, 1998

Mr. Frank A. DeBacker
UtiliCorp United
10700 East 350 Highway
Kansas City, MO 64138

Dear Mr. DeBacker:

This letter is in response to your August 25, 1998 letter regarding your RFP process for Missouri Public Service power supply.

Basin Electric continues to have an interest in providing power supply resources to Missouri Public Service. The terms and conditions outlined in my July 2, 1998 letter to Mr. Kiah Harris remain valid, however, Basin Electric continues to reserve the right to withdraw this offer at any time.

Sincerely,

Robert L. McPhail
General Manager

tsc/ms
cc: Wayne Backman
David Raatz
Tom Christensen

CP&L

Carolina Power & Light Company
PO Box 1551
411 Fayetteville Street Mall
Raleigh NC 27602

September 4. 1998

Mr. Frank A. DeBacker
Utilicorp United / EnergyOne
10700 East 350 Highway
Kansas City, MO 64138

Re: Price increase to proposal dated July 2, 1998

Dear Mr. DeBacker:

CP&L does have a continued interest in supplying peaking capacity and energy to Missouri Public Service. However. we can no longer meet the year 2000 requirement. The first in service date available would be in the year 2001. CP&L will also have to increase our prices by fifteen percent. The specifics of our proposal also will require assistance from Missouri Public Service on site location and development.

The consummation of the proposals provided herein is subject to the execution of a mutually agreeable contract and the approval of our respective management. By accepting these proposals for review, Utilicorp Energy Group agrees that these proposals in their entirety shall remain confidential, except as required to be disclosed by law and only to the extent required by law. CP&L shall be notified prior to any release of information contained in these proposals. This offer will expire on September 30, 1998. Please let me know if these conditions are not acceptable to Utilicorp Energy Group.

We appreciate the opportunity to update and modify our original proposal and look forward to hearing from you in the future. Please do not hesitate to call me at 919-546-5267 if you have any questions.

Yours truly,

Karla Haislip

Karla Haislip
Bulk Power Marketer

WHOLESALE
ENERGY GROUP

INTRODUCTORY MEETING

MISSOURI PUBLIC SERVICE

November 9, 1998

Jack L. Farley
Vice President
(713) 207-3271

Richard Benedict
Director
(713) 207-6823

Terry Lane
Marketing Director
(713) 207-5117

INTRODUCTION TO HOUSTON INDUSTRIES WHOLESALE ENERGY GROUP (HIWEG)

- Parent - Houston Industries, Inc.
- Accomplishments
- Capabilities
- Relative comparison

SCHEDULE FAD-16
Page 2 of 8

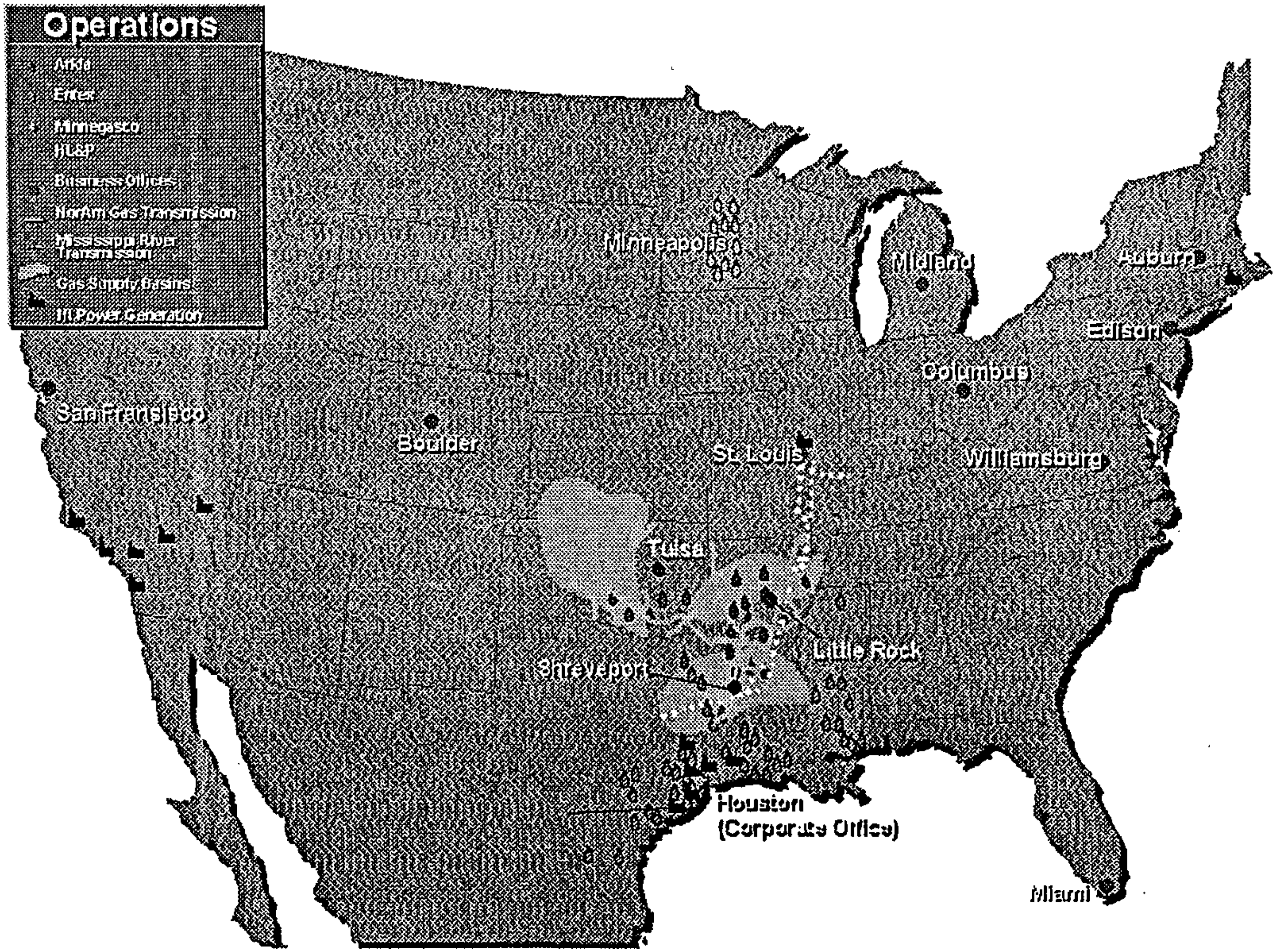
HIWEG PARENT - HOUSTON INDUSTRIES, INC.

- Houston Industries, Inc. (HI)
  - HI Wholesale Energy Group
    - Power Operations
    - Asset Development
    - Power and Gas Orgination
    - Power and Gas Trading
    - Interstate Pipelines & Gathering
  - HI Retail Energy Group
    - HL&P Division
    - Arkla
    - Minnegasco
    - Entex
    - HI Retail Marketing
  - HI Energy (International)

- *12.8 million retail customers world-wide*
- One of top 5 gas and power utilities in United States
  - 3.8 million customers
  - $18 billion in assets
- 17,840 MW of generation assets
  - 14,040 MW regulated
  - 3,780 MW unregulated
  - >1,500 MW under development
- Top 10 power and gas marketer
  - Largest end-user of gas in United States
  - 80 million MWh unregulated power volumes annually
  - 4.0 BCF/D unregulated gas volumes in 1997
- Major mid-continent gas transmission system
  - NorAm Gas Transmission and Mississippi River Transportation

WHOLESALE
ENERGY GROUP

HOUSTON INDUSTRIES, INC. - DOMESTIC BUSINESS OPERATIONS



SCHEDULE FAD-16
Page 4 of 8

UNREGULATED UPSTREAM ASPIRATION

Build a top 5 generation and wholesale marketing business

- 25,000+ MW in generating assets; multi-billion dollar investment
  - Greenfield development, asset acquisition and corporate acquisition
  - Major regional presence in Texas, Western United States and Mid-continent
- Industry leading upstream skills
  - Asset development, marketing, trading, operations, dynamic control systems
- Complementing (and leveraging) existing pipeline, gathering and storage assets

SCHEDULE FAD-16
Page 5 of 8

HI WHOLESALE ENERGY GROUP ACCOMPLISHMENTS

- Operate 17,840 MW of domestic generation
  - 14,040 MW regulated (9,335 MW gas, 3,855 MW coal/lignite, 770 MW nuclear)
  - 3,780 MW unregulated (100% gas)
  - Over 2,000 MW mature developments, announced projects include:
    - 480 MW CCGT under construction in Nevada (El Dorado)
    - 650 MW Cogen in Roxana, Illinois (Cardinal Energy)
    - 100 MW Cogen under construction in Texas (Sabine)
    - 500 MW CCGT in Rhode Island (Hope)
- Manage three control areas in Texas and provide services to two others
  - Developed best-in-industry systems and processes
- Optimize 3,780 MW California supply portfolio on a day-ahead and hour-ahead basis across the fuel, power and ancillary services markets

SCHEDULE FAD-16
Page 6 of 8

HIPG GAS TURBINE EXPERIENCE

- Simple Cycle Gas Turbines (summer rating @ 100 degrees F)

–Turbodyne	6 x 57 MW	342 MW
–GE 7C	6 x 58 MW	348 MW
–GE 5L	6 x 13 MW	78 MW
–Westinghouse	4 x 13 MW	52 MW
–Westinghouse	1 x 23 MW	23 MW

- Combined Cycle Gas Turbines (summer rating @ 100 degrees F)
  - –2 GE Stag 407 Combined Cycle Units 672 MW

- Cogeneration Gas Turbine Plants (summer rating @ 97 degrees F)
  - –Shell - Deer Park
    - 2 GE 7EA's ABB HRSG's 164 MW/1,000 Klb/hr steam
  - –San Jacinto
    - 2 GE 7EA's/2 Deltak HRSG's 164 MW/700 Klb/hr steam

CAPABILITIES OF HI WHOLESALE ENERGY GROUP

Own and operate large regional generation and supply portfolio.

1. Acquire existing generation
2. Provide control area services (e.g., back-up power, load control)
3. Develop and manage construction of new greenfield generation
4. Operate fossil fuel generation facilities in cost effective manner
5. Purchase low cost fuel, power, transmission and ancillary services in spot and term markets
6. Provide term risk management of fuel and power prices
7. Finance generation asset projects

NorAm Energy Services, Inc.

A Subsidiary of Houston Industries Incorporated

December 1, 1998

Frank A. DeBacker
Utilicorp United
P.O. Box 11739
Kansas City, MO 64138

Dear Mr. DeBacker:

As a result of our meeting at your office on November 9, 1998, Houston Industries is submitting the attached Long-Term Peaking Capacity and Energy Proposal for discussion purposes. We look forward to discussing it in detail with you in the near future.
If you have questions or comments, please call me at 713.207.5117.

Sincerely,

Terry D. Lane

Terry D. Lane
Marketing Director, MAPP/SPP

P.O. Box 4455 • Houston, TX 77210-4455 • 713 / 207-5072 • FAX 713 / 207-9626

LONG-TERM PEAKING CAPACITY AND ENERGY PROPOSAL

Buyer:	UtiliCorp United d.b.a Missouri Public Service Company (MPS)
Seller:	Houston Industries Power Generation and NorAm Energy Services (HIPG/NES)
Term:	Five years starting June 1, 2001 and ending May 31, 2006
Capacity:	300 MWs at 99 degrees F; 326 MW at 55 degrees F (yearly average)
Delivery Point:	MPS Pleasant Hill Substation
Capacity Price:	\$4.50/kW-mo (escalated at 2.5% per contract year) paid on the average annual Capacity of 326 MWs; includes 16" lateral pipeline cost.
Energy Price:	For all hours, MPS will have the option to call on the Energy at \$1.00/MWh (escalated at 2.5% per contract year) plus the product of a 10,600 Btu/kWh heat rate and the natural gas fuel cost.
Flexibility:	MPS has full dispatch rights to 300 MWs limited only by the scheduling provisions below and the operational constraints of the unit (such as, but not limited to, a 4 hour minimum run time).
Fuel:	Natural gas supply and transportation will be managed by Seller. Seller will supply fuel at a mutually acceptable index, adjusted for delivery to the generating facility, along with a fixed charge for six Summer months of Firm Transportation. Seller will maintain Firm Transportation for natural gas for the generating facility in the November through April period.
Unit Starts:	MPS will not be charged for the first 50 starts per contract year. MPS will be charged \$2,500 per start for the second 50 starts per contract year. However, should MPS request more than 100 starts per contract year, MPS will be subject to paying incremental increases in maintenance and operating costs.
Scheduling:	MPS will notify Seller of total planned output and number of starts by 9:00 AM Central Prevailing Time (CPT) one business day prior to flow so that fuel can be procured and transported. If MPS provides a schedule after the 9:00 AM deadline, the gas price component of the Energy Price will be based on actual purchase cost and actual production from the unit will be conditioned on fuel availability.

Availability:	The development plan envisions using proven technology which has historically attained very high availability levels. Availability targets will be set following further development effort. Seller envisions targets of 98% for all hours during the six Summer months. To provide appropriate operational incentives, the capacity payment will be adjusted (up or down) based upon actual performance relative to a specific target during the six Summer months of May through October.
Operations:	HIPG will be responsible for managing operations and maintenance in accordance with generally accepted utility practices. MPS and Seller will cooperate to set scheduled maintenance outages. MPS will provide an on-site operations staff to Seller under a separate agreement.
Transmission:	MPS will cooperate with Seller to accelerate the planned connection of the Pleasant Hill Substation to the 345 kv system.
Site:	Under separate agreement, Seller will acquire approximately 70 acres of land near the Pleasant Hill Substation from MPS for approximately $3000 per acre.
Resale:	In periods where MPS has not scheduled the Energy, Seller will have the right to sell the Energy.
Credit Support:	The Seller's contract obligations are backed by a multi-billion dollar corporation with an investment grade rating. MPS's contract obligations are backed by ____________.
Note:	If MPS provides fuel to the facility under a tolling arrangement, Seller will require access to Incremental Firm Transportation of natural gas for: (a) Any Energy sales above the 326 MWs contracted for by MPS (b) Energy sales by Seller when MPS does not call on its Energy (c) Energy sales from this facility after the termination of this five-year agreement, if it is not renewed by both parties.

This document is not intended to create a binding offer or contract of purchase and sale of electric power or natural gas between MPS and Seller. Moreover, this document does not in any way whatsoever obligate either of the parties to enter into any agreements or to proceed with any possible relationship or transaction. The terms and conditions set forth above are subject to negotiation, completion and incorporation into and the execution by both parties of a definitive agreement. Either party may terminate discussions and/or negotiations regarding this document at any time.

Mid December

Notified HI that their proposal was not low bid.

12/29/98 - 8:30 AM RAYTOWN

MET with HI to DISCUSS their proposal & offer them opportunity to revise proposal.

Proposal to:

Missouri Public Service Co.

January 6, 1999

Assumptions - OCGT

- 500MW OCGT facility built on MPSC site
  - 10,600 net unit heat rate
  - Availability guarantee of 98% in summer
- Capacity available year round - 500 MW
- Day ahead scheduling
- Strike at Spot Natural Gas Price x Heat Rate
- Energy from lowest cost source
  - Market
  - Peaker

Analysis methodology

- Simulate hour by hour forward market
- Simulate MPS plant dispatch and wholesale market activity
  - –Plant analysis - forced and scheduled outages
  - –Market analysis - Optimization of plants vs. market power
- Simulate OCGT capacity and match to MPS demand shape
  - – Only run OCGT when economical relative to prevailing market
  - – Determine "credit" for merchant capacity
- Determine overall cost to serve demand with OCGT configuration

Analysis Methodology - continued

- Simulate CCGT capacity and match to MPS demand shape and proposed seasonal capacity arrangement
  – Only run CCGT when economical relative to prevailing market
  –Determine "credit" for merchant capacity
- Major CCGT Assumptions
  - Heat Rate at 6200 Btu/kWh
  - Capacity Charge $7.50/kW-Mo.
  - $2.00/MWh Variable O&M (start-up, chemicals, water, etc.)
- Determine overall cost to serve demand with CCGT configuration
- Revise HI's initial OCGT offering to match CCGT economics

Results of Analysis

- HIPG's initial proposal was 5% higher than CCGT proposal
  - Not an "apple to apple" comparison due to varying risk profiles
- Significant portion of the value in CCGT proposal is from the resale of excess energy to the market
  - Higher merchant risk to MPS vs OCGT proposal
  - Significantly more risk to MPS in bear market than OCGT proposal
- Actual demand curves show that 500 MW of capacity needed in four summer months not six months
  - CCGT offering needs the two additional months to make economics work
- Revised OCGT proposal makes apparent cost equal to CCGT
  - Reduced merchant risk
  - Market upside potential with limited down-side risk
  - Matches load profile more efficiently

Regulatory capacity

- 200 MW of winter and shoulder capacity fully NERC creditable in SPP

- 500 MW of "Summer Peaking" capacity fully NERC creditable in SPP (meets 4-month criteria)

RECVD: 1/6/99 1100

LONG-TERM PEAKING CAPACITY AND ENERGY PROPOSAL

Buyer:	UtiliCorp United d.b.a Missouri Public Service Company (MPS)
Seller:	Houston Industries Power Generation and NorAm Energy Services (HIPG/NES)
Term:	Five years starting June 1, 2001 and ending May 31, 2006
Capacity:	The following two capacity divisions apply: 1) 500 MWs for the period of June, 1 through September, 30 for each year in the Term of the agreement . 2) 200 MWs for the periods of January, 1 through May, 31 and October, 1 through December, 31 for each year in the Term of the agreement.
Delivery Point:	MPS Pleasant Hill Substation / MPS INTERCONNECTS
Capacity Price:	$8.42/kW-mo for 500 MWs supplied in the June, 1 through September, 30 period specified above. $4.21/kW-mo for 200 MWs supplied in the January, 1 through May, 31 and October, 1 through December, 31 periods specified above. The Capacity Prices include the cost of a 16 inch lateral pipeline to serve the generating facility.
Energy Price:	For all hours, MPS will have the option to call on the Energy at $0.75/MWh plus the product of a 10,600 Btu/kWh heat rate and the natural gas fuel cost. HHV
Flexibility:	MPS has full dispatch rights to purchased Capacity limited only by the scheduling provisions below and the operational constraints of the unit (such as, but not limited to, a 4 hour minimum run time).
Fuel:	Natural gas supply and transportation will be managed by Seller. Seller will supply fuel at a mutually acceptable index, adjusted for delivery to the generating facility, along with a fixed charge for six Summer months of Firm Transportation. Seller will not maintain Firm Transportation for natural gas for the generating facility in the November through April period.
Unit Starts:	MPS will not be charged for the first 50 starts per contract year. MPS will be charged $2,500 per start for the second 50 starts per contract year. However, should MPS request more than 100 starts per contract year,

MPS will be subject to paying incremental increases in maintenance and operating costs.

Scheduling: MPS will notify Seller of total planned output and number of starts by 9:00 AM Central Prevailing Time (CPT) one business day prior to flow so that fuel can be procured and transported.

If MPS provides a schedule after the 9:00 AM deadline, the gas price component of the Energy Price will be based on actual purchase cost and actual production from the unit will be conditioned on fuel availability.

Availability: The development plan envisions using proven technology which has historically attained very high availability levels. Availability targets will be set following further development effort. Seller envisions targets of 98% for all hours during the four Summer months. To provide appropriate operational incentives, the capacity payment will be adjusted (up or down) based upon actual performance relative to a specific target during the four Summer months of June through September.

Operations: HIPG will be responsible for managing operations and maintenance in accordance with generally accepted utility practices. MPS and Seller will cooperate to set scheduled maintenance outages. MPS will provide an on-site operations staff to Seller under a separate agreement.

Transmission: MPS will cooperate with Seller to accelerate the planned connection of the Pleasant Hill Substation to the 345 kv system.

Site: Under separate agreement, Seller will acquire approximately 70 acres of land near the Pleasant Hill Substation from MPS for approximately $3000 per acre.

Resale: In periods where MPS has not scheduled the Energy, Seller will have the right to sell the Energy.

Credit Support: The Seller's contract obligations are backed by a multi-billion dollar corporation with an investment grade rating. MPS's contract obligations are backed by ____________.

Note: If MPS provides fuel to the facility under a tolling arrangement, Seller will require access to Incremental Firm Transportation of natural gas for:

(a) Any Energy sales in excess of the Capacity specified above contracted for by MPS

(b) Energy sales by Seller when MPS does not call on its Energy

(c) Energy sales from this facility after the termination of this five-year agreement, if it is not renewed by both parties.

This document is not intended to create a binding offer or contract of purchase and sale of electric power or natural gas between MPS and Seller. Moreover, this document does not in any way whatsoever obligate either of the parties to enter into any agreements or to proceed with any possible relationship or transaction. The terms and conditions set forth above are subject to negotiation, completion and incorporation into and the execution by both parties of a definitive agreement. Either party may terminate discussions and/or negotiations regarding this document at any time.

1/6/98

Rcvd revised proposal from HI in mtg
A UPS offices in Raytown

HI	UPS
	FAD
	Bob H.

1/12/99 AM

Notified HI that their proposal was much improved but still not low bid

1/13/99 3:00

Conf call w/ HI to discuss their proposal
Agreed to give them until 12:00 noon
on 1/14/99 to revise their offer.

1/14/99 11:15

Conf Call w/ Richard Benedict of HI

They ~~are w/thdrawing~~ are maintaining their offer at current pricing - are not able to improve

- will maintain offer for a short time in event other proposal fall thru.

10750 East 350 Highway
P.O. Box 11739
Kansas City, Missouri 64138

UTILICORP UNITED

January 15, 1998

Mr. Richard L. Benedict
Director, Wholesale Power Group
Houston Industries Inc.
P.O. Box 286
Houston, TX 77001-0286

Subject: **Houston Industries Power Generation Proposal**

Dear Richard:

The purpose of this letter is to inform you that the Houston Industries Power Generation (HI) Proposal of December 1, 1998 (including previous proposals from NP Energy and NorAm and revised proposal of January 6, 1999) has not been selected as the preferred supply side resource in Missouri Public Service's (MPS) 1998 Integrated Resource Planning Process.

As you know, MPS is required to select the lowest cost alternative available when it adds power supply resources. Your proposal did not provide MPS with the lowest cost power supply.

UtiliCorp Power Services (UPS) wishes to thank you for your sincere interest and participation in its solicitation process.

Please feel free to contact me at (816) 936-8639 if you have any questions.

Sincerely,

Frank A. DeBacker

Frank A. DeBacker
V.P. - Fuel & Purchased Power

cc: Robert Holzwarth
John W. McKinney

1/29/99

Phone call w/ Richard Benedict of HI

1) HI proposal not contingent on Financial closing would be contingent on getting permits, zoning, etc.

2) HI proposal would include limits on capacity payments in event a FM made plant inoperable for long periods

Aquila Power Corporation
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
Fax: 816-936-8775

AQUILA ENERGY

November 30, 1998

Mr. Frank DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, MO 64138

Subject: Proposal to Supply Capacity and Energy for Missouri Public Service (MPS)

Dear Mr. DeBacker:

Aquila Power Corporation (APC) is pleased to modify its July 6, 1998 proposal to MPS for the provision of capacity and energy. This proposal revises the July 6 proposal for the period beginning June 1, 2001, with certain terms and conditions identified herein to remain the same. APC also looks forward to finalizing the terms and conditions of the call option sale to MPS for the period June 1, 2000 through September 30, 2000.

This proposal identifies two sources of capacity to meet MPS' requirements. The primary source of capacity is from a combined cycle gas turbine generation facility to be located on property currently owned or controlled by MPS in or around Pleasant Hill, Missouri. This proposal is contingent upon MPS leasing or selling this property to APC or its designated affiliate. The second source of capacity is from a combined cycle generator in Batesville, Mississippi, identified and described in the July 6 bid.

During the summer months June through September of 2001, the Missouri generation facility will be available in a simple cycle configuration only. Conversion to a combined cycle configuration will require that the facility come off-line for approximately the final three months of the year. Starting January 1, 2002, the generation station will be available in a combined cycle operating mode. The proposal herein reflects how APC will source capacity to meet MPS' requirements prior to the time that the combined cycle configuration is completed.

This proposal shall remain valid for 90 days, unless otherwise extended by APC. Certain pricing provisions will be subject to revision due to changing market conditions for power sourced from the Batesville, Mississippi power plant.

APC thanks you for the opportunity to submit this revised proposal. Should you have any questions, please do not hesitate to contact me at (816) 936-8622. We look forward to meeting MPS' capacity needs.

Very truly yours,

Mike Jonagan

Mike Jonagan
Director - Power Marketing
Aquila Power Corporation

cc: V.J. Horgan
Joe Gocke
David Stevenson

DESIGNATED GENERATION

APC proposes to meet MPS's capacity requirements from the following capacity sources:

Missouri Generator

The Missouri Generator is a proposed power generation station built on property currently owned or controlled by MPS in or around Pleasant Hill, Missouri. The generator will be interconnected to the MPS transmission system. APC or its designated affiliate will develop, construct, own, and operate the generator (the "Missouri Generator").

The Missouri Generator will be constructed in phases. By June 1, 2001, the generator will be constructed and fully operational in simple cycle mode. This will consist of two "F" class gas turbines with a nominal power output rating of approximately 320 MW. The equipment vendor has not been selected at this time. The generator will operate in simple cycle mode from June 1, 2001 through September 30, 2001. At that time, the generator will be removed from service and construction completed on the combined cycle configuration during the three remaining months of 2001.

APC intends to initiate construction of the generator during the fourth quarter of 1999. Preparation of the Prevention of Significant Deterioration permit is complete and will be filed as an application once MPS represents to APC that it owns or controls the property on which the plant will be built. Significant progress has been made in other areas of development, including initial negotiation with EPC vendors.

The Capacity and Energy Prices quoted herein are based on APC developing, owning and operating the Missouri Generator. APC will construct a pipeline header system connecting the generator to two of three interstate pipelines, including Williams, Panhandle Energy, and KNI. The prices do not include the acquisition of firm gas transportation from any of the pipelines. APC believes that MPS is in the best position to negotiate with the pipelines the firm gas transportation required to meet its needs.

The Capacity and Energy Prices additionally assume that APC will be able to purchase "F" class gas turbines with the approximate capacities identified herein at prices no greater than $32 million per turbine. To the extent that turbine prices exceed that amount, APC will be required to increase its capacity price to MPS based on a pro rata distribution of the term of the final contract with MPS to the expected 30 year life of the facility. Additionally, the capacity quantities quoted in this proposal are estimates based on information supplied by an equipment manufacturer. APC reserves the right to adjust the capacity quantity described in this proposal based upon actual contract capacity of the new plant.

Batesville, Mississippi Project

During the period June 1, 2001 through December 31, 2001, APC is proposing to dedicate capacity as detailed under Option #3 in the Capacity Bid section of this proposal from a 279 MW combined cycle generating unit under construction in Batesville, Mississippi. Please refer to APC's July 6, 1998 bid for additional detail regarding this facility. The facility has a scheduled in-service date of June 1, 2000, a full year prior to the designated time period in this proposal.

CAPACITY BIDS

APC proposes to meet MPS' capacity requirements by giving MPS the option to select capacity for certain time periods from the designated generators. The options being offered, and the corresponding terms, are as follows:

Option 1: Missouri Generator Four Year Toll

Time Periods	Capacity	Capacity Price ($/kWmo)
June 1, 2001 - September 30, 2001	320 MW	$6.20
January 1, 2002 - May 31, 2005	200 MW	$6.40
April 1 - September 30, 2002-2005	300 MW	$8.00

Option 2: Missouri Generator Fifth Year Extender

Time Periods	Capacity	Capacity Price ($/kWmo)
June 1, 2005 - May 31, 2006	200 MW	$7.50
June 1 - Sept 30, 2005	300 MW	$9.00
Apr 1 - May 31, 2006	300 MW	$9.00

Option 3: Batesville, Mississippi 2001 Unit Contingent Call Option

Time Period	Capacity	Capacity Price ($/kWmo)
June 1, 2001 - September 30, 2001	180 MW	$7.90
October 1, 2001 - December 31, 2001	200 MW	$0.50

Summary

The Options have been designed to meet MPS's capacity requirements as understood by APC. Collectively, the options provide 500 MW of capacity to MPS during the all summer seasons of April 1 through September 30, and a minimum 200 MW of capacity to MPS during the winter season of October 1 through March 31.

Please note that all energy and capacity values are quoted at the appropriate generator bus.

11,040
3840
14,880

ENERGY PRICE

Options 1 and 2: Missouri Generator Four Year Toll and Fifth Year Extension

MPS will be required to arrange for and buy all gas associated with start ups, shutdowns, and operation of the power station under a tolling arrangement. The cost of conversion will be \$1.25/MWh, escalated from 1998 at the Producer Price Index.

Time Periods	Guaranteed Heat Rate (MMBtu (HHV)/MWh)*
June 1, 2001 - September 30, 2001	Approximately 11.1
All other summer periods	Approximately 7.0
All other winter periods	Approximately 7.8

* The final Guaranteed Heat Rate will be based on equipment manufacturer's design. The values for the first two Time Periods assume full load operation. Operation at part load will result in a higher (worse) heat rate.

Option 3: Batesville, Mississippi 2001 Unit Contingent Call Option

Time Periods	Price
All periods	\$200.00/MWH

AVAILABILITY

Missouri Generator

APC or its designated affiliate will be responsible for maintaining the unit in accordance with equipment manufacturer recommendations. APC will guarantee the availability of the generator to MPS at a monthly average rate of 94%. The Capacity Price paid to APC will be reduced pro rata each month that availability is less than 94%.

Batesville, Mississippi Project

Please refer to APC's July 6, 1998 bid for information pertaining to operation and maintenance.

APC will guarantee a minimum availability of 93% each month after the unit achieves commercial operation.

SCHEDULING

Missouri Generator

The generator shall be fully dispatchable by MPS within the design limitations of the equipment manufacturer, to be determined, and consistent with prudent industry practices. The minimum run time shall be sixteen (16) hours and the plant may be started only once each day. MPS shall be responsible for nominating and scheduling gas to the pipeline header system to be constructed by APC or its affiliate. MPS will schedule energy by 10:00 AM CPT one business day prior to the day of the schedule. This pricing does not include the cost for firm gas transportation to the site.

Batesville, Mississippi Project

Scheduling requirements will be consistent with APC's July 6, 1998 bid with the exception that the minimum run time shall be sixteen (16) hours.

DELIVERY POINTS

Missouri Generator

APC shall deliver energy to the interconnection of the Missouri Generator with the MPS transmission system or any other MPS interface at APC's sole discretion. MPS agrees to enter into an interconnection agreement between itself and the company or partnership to be established that will own the power generator. This proposal includes a cost of $5,560,000 to make the transmission system upgrades required to interconnect the Missouri Generator to the MPS transmission system. The capacity charges contained in this proposal will be adjusted accordingly if this cost is changed. To the extent such upgrades need not be borne by APC or its designated affiliate, APC will reduce the Capacity Price to MPS for Option 1 and Option 2, such reduction to be pro rata. Likewise, to the extent such upgrades cost more than $5,560,000, APC will increase the Capacity Price to MPS for Option 1 and Option 2, such increase to be pro rata.

Batesville, Mississippi Project

See July 6, 1998 bid.

CONDITIONS PRECEDENT

Any agreement entered into between APC and MPS shall have certain conditions precedent to the effectiveness of the agreement, including but not limited to:

1. APC receipt of all required regulatory approvals, including Federal Energy Regulatory Commission.
2. UCU Board and management approval to develop, own and construct the Missouri Generator.
3. For the Missouri Generator, achieving financial close no later than December 1, 1999 unless such condition is waived by APC.
4. For the Batesville, Mississippi Project, acquisition of firm transmission service as directed by MPS.
5. Completion of construction and reaching commercial operation for both the Missouri Generator and the Batesville, Mississippi generators.

CONTRACT TERMINATION OPTIONS

APC proposes to provide MPS the option to terminate the contract under the following conditions:

I. The option to terminate is available for contract years beginning June 1, 2002. A contract year is defined as any 12 consecutive-month period beginning June 1 and ending May 31.

II. MPS must notify APC no later than March 1 prior to the first contract year for which the option is exercised. For example, MPS must notify APC no later than March 1, 2003 to terminate the contract beginning June 1, 2003.

III. The termination option cannot be exercised on partial contract years.

Option Pricing: MPS will pay APC an option premium for each month for which the termination option may be exercised. This premium is paid every month for which the termination option may be exercised irrespective of whether the option is exercised.

Option 1: Missouri Generator Four Year Toll

$0.90 per kW Month

Option 2: Missouri Generator Fifth Year Toll Adder

$0.90 per kW Month

10700 East 350 Highway
Kansas City, Missouri 64138

December 9, 1998

UtiliCorp United
EnergyOne

Mr. Mike Jonegan
Director - Power Marketing
Aquila Power Corporation

Subject: Aquila Proposal dated November 30, 1998

Dear Mr. Jonegan:

Missouri Public Service (MPS) is in receipt of Aquila's modified proposal submitted in response to MPS' Request for Proposal issued May 22, 1998.

After preliminary review and analysis of Aquila's proposal, MPS has several questions and areas in which clarification is needed.

1. The capacity price quoted is based on a $32 million purchase price for the combustion turbines. What is the basis for the $32 million figure? That is: Is the price FOB plant site or factory? Does the price include all taxes? Does the price include spares? If the price of the combustion turbines increases 5%, what will be the resulting capacity price?

2. Option 3 is for purchase from Aquila's Batesville project. What will be the cost of transmission (including losses) from the project to the MPS system?

3. What heat rates will apply to purchases at levels less than full output of the facility?

4. The proposal states that MPS shall schedule energy by 1000 the previous business day. Under what conditions will MPS be able to schedule energy on short notice (less than 14 hours but greater than 1 hour)?

Please respond to the above questions at your earliest convenience.

Sincerely,

Frank A. DeBacker

Frank A. DeBacker
V.P. - Fuel & Purchased Power
UtiliCorp Power Services

c: R. Holzwarth
J. McKinney

RCVD 12/22 0751

Aquila Energy Marketing Corporation
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
Fax: 816-936-8775

AQUILA ENERGY

December 17,1998

Mr. Frank DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, MO 64138

Subject: Proposal to Supply Capacity and Energy for Missouri Public Service - Revision regarding land

Dear Mr. DeBacker:

This letter is a revision to the proposal submitted November 30, 1998 regarding the land on which the proposed Missouri Generator would be located. In that proposal, APC stated that the proposal was contingent upon MPS leasing or selling this property to APC or its designated affiliate. APC hereby revises that letter to remove that contingency. In fact, APC or its designated affiliate will procure ownership of the land on which the Missouri Generator is proposed to be located. The APC proposal thereby does become contingent upon the ability of APC to procure that property, or rights to construct a power station on that property, no later than January 15, 1999.

Should you have any questions, please do not hesitate to contact me at (816) 936-8622.

Very truly yours,

Mike Jonagan

Mike Jonagan
Director - Power Marketing
Aquila Power Corporation

cc: V.J. Horgan
Joe Gocke
David Stevenson
Rob Freeman
John McKinney

Rcvd 0923
12/22/98

Aquila Energy Marketing Corporation
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
Fax: 816-936-8775

AQUILA ENERGY

December 22, 1998

Mr. Frank DeBacker
V.P. Fuel & Purchased Power
UtiliCorp Power Services
10700 East 350 Highway
Kansas City, MO 64138

Dear Frank:

The following are Aquila Power Corporation's responses to the questions asked in your December 9, 1998 letter.

Question 1

The capacity price quoted is based on a $32 million purchase price for the combustion turbines. What is the basis for the $32 million figure? That is: Is the price FOB plant site or factory? Does the price include all taxes? Does the price include spares? If the price of the combustion turbines increases 5%, what will be the resulting capacity price?

Answer 1

The combustion turbine price of $32,000,000 per unit is current as of 11/30/98 based on a telephone quote (confirmed by fax) from both GE and Westinghouse solicited by Black & Veatch. This quote is specific to the Cass County project for both vendors.

The price includes standard terms and conditions which transfer title to the equipment to the Owner "Ex-Works" while risk of loss or damage remains with the vendor until arrival on board carrier at the nearest published accessible rail siding (for rail shipments) or on board carrier at the jobsite (for truck shipments).

The rail or truck freight from the factory is included in the $32,000,000 price.

The heavy haul from the rail siding to the plant site is NOT included in the $32,000,000 price.

There are NO taxes included in the $32,000,000 price.

There are NO spare parts included in the $32,000,000 price.

The Owner has incorporated an allowance for the heavy haul, taxes, and a major maintenance and spare parts program into the capacity price as bid.

The capacity price as bid is currently variable and directly proportional to the price of the combustion turbines. Any savings or increases resulting from a "committed price" (secured by a down payment) for the combustion turbines will be passed through to the capacity price without any markup by APC.

Every $1,000,000 increase in the $32,000,000 combustion turbine price quoted in the proposal will result in the quoted capacity price increasing $0.055 per kWmo for Option #1 only. Thus, a 5% increase in the turbine price would be $1,600,000, resulting in a quoted capacity price increase for Option #1 equal to $0.088 per kWmo.

Question 2

Option 3 is for purchase from Aquila's Batesville project. What will be the cost of transmission (including losses) from the project to MPS system?

Answer 2

It is our understanding that you no longer have an interest in Option 3.

Question 3

What heat rates will apply to purchases at levels less than full output of the facility?

Answer 3

	MW Output	Heat Rate (MMBtu/MWh)
Simple Cycle		
	320	11.1
	240	12.2
	161	13.8
	160	11.1
	80	12.2
Combined Cycle	500	7.0
	375	7.5
	251	8.3
	250	7.2
	200	7.8
	150	8.2
	100	9.5

NOTE: Only the base load heat rates as quoted are guaranteed for this proposal and these are subject to the final plant design to be specified in the Engineering, Procurement, and Construction Contract. Part load heat rates are rarely guaranteed by vendors without payment of additional premium. No such part load guarantees are included in the capacity price as bid.

Part load heat rates will vary significantly as a function of the method of load reduction (increase) on the combustion turbines and the timing point at which a combustion turbine is removed (added) from service.
The final method and timing will generally be defined by the operating (emissions) restrictions included in the Air Emissions Permit.

Question 4

The proposal states that MPS shall schedule energy by 1000 the previous business day. Under what condition will MPS be able to schedule energy on short notice (less than 14 hours but no sooner than 4 hours)?

Answer 4

Attached please find a revised page 3 from our November 30, 1998 proposal. These prices reflect a minimum of four (4) hours notice to schedule energy. All other terms and conditions would remain the same.

Please let me know if you have any additional questions.

Sincerely,

Mike Jonagan

Mike Jonagan
Director - Power Marketing
Aquila Energy Corporation

cc: V.J. Horgan
Joe Gocke
David Stevenson
Rob Freeman
John McKinney

CAPACITY BIDS

APC proposes to meet MPS' capacity requirements by giving MPS the option to select capacity for certain time periods from the designated generators. The options being offered, and the corresponding terms, are as follows:

Option 1: Missouri Generator Four Year Toll

Time Periods	Capacity	Capacity Price ($/kWmo)
June 1, 2001 - September 30, 2001	320 MW	$6.40
January 1, 2002 - May 31, 2005	200 MW	$6.40
April 1 - September 30, 2002-2005	300 MW	$8.00

Option 2: Missouri Generator Fifth Year Extender

Time Periods	Capacity	Capacity Price ($/kWmo)
June 1, 2005 - May 31, 2006	200 MW	$7.50
June 1 - Sept 30, 2005	300 MW	$9.00
Apr 1 - May 31, 2006	300 MW	$9.00

Option 3: Batesville, Mississippi 2001 Unit Contingent Call Option

Time Period	Capacity	Capacity Price ($/kWmo)
June 1, 2001 - September 30, 2001	180 MW	$8.90
October 1, 2001 - December 31, 2001	200 MW	$0.75

Summary

The Options have been designed to meet MPS's capacity requirements as understood by APC. Collectively, the options provide 500 MW of capacity to MPS during the all summer seasons of April 1 through September 30, and a minimum 200 MW of capacity to MPS during the winter season of October 1 through March 31.

Please note that all energy and capacity values are quoted at the appropriate generator bus.

Aquila Energy Marketing Corporation
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
Fax: 816-936-8775

January 6, 1999

AQUILA ENERGY

Mr. Frank DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, MO 64138

Subject: APC Proposal of November 30, 1998 to Supply Capacity and Energy for Missouri Public Service - Identification of Legal Entity That Will Develop Missouri Generator

Dear Mr. DeBacker:

Pursuant to our conversation, this letter serves to identify the specific legal entity that will develop, construct and own the Missouri Generator that is the subject of the referenced Proposal.

Aquila Energy Corporation has established a wholly owned subsidiary, MEP Holdings, Inc. d/b/a Merchant Energy Partners, that is engaged in energy asset acquisitions and development through special purpose subsidiary companies. The Missouri Generator will be owned by such a special purpose entity, to be established upon notification from MPS of the awarding of the project to Aquila. This will also be the contracting entity with MPS on the project.

Accordingly, from this point forward all communications on this project will be from Merchant Energy Partners' management.

Please let me know if you have any questions. Thank you.

Sincerely,

Mike Jonagan
Director - Power Marketing
Aquila Power Corporation

cc: Max Sherman
Laurie Hamilton

Merchant Energy Partners
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
816-936-8712
Fax: 816-936-8724
Pager: 800-431-7491

AQUILA ENERGY

January 7, 1999

Max A. Sherman
Senior Director
Origination

Mr. Frank A. DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, Missouri 64138

Subject: Power Supply RFP for Missouri Public Service (MPS)

Dear Frank:

This letter responds to several of the issues you raised in a meeting with Merchant Energy Partners (MEP) personnel on January 4, and additionally in a conversation with me this morning. This letter attempts to clarify, on those points, the rough draft contract we provided for MPS review on December 24, 1998. In particular:

1. Assurances on the Summer 2001 Commercial Operation Date.

   a. A detailed project schedule, which we are prepared to provide for your review, indicates MEP can achieve a mid-summer 1999 financial closing date and issuing a Full Notice to Proceed to the EPC contractor. The present schedule calls for that on July 29. We believe, for staged construction involving simple cycle commercial operation to meet a June 1, 2001 deadline, there is easily 3 months of margin in that schedule (e.g, the June 1, 2001 date can be achieved if Full Notice to Proceed were as late as October 1999).

   b. We are still considering your liquidated damages question for the summer of 2001.

   c. We assume the January 2002 commercial operation date for the plant in combined cycle configuration is less of an issue than Summer 2001, and have therefore not focused on that item.

2. Scheduling flexibility. MEP is willing to revise Article 6 – Scheduling to provide for the following deal points in response to your articulated need for scheduling flexibility:

a. Day-ahead scheduling submitted by MPS to MEP.

b. MEP can relax the minimum run time of 16 hours; we are considering a minimum of eight (8) hours when committing the plant in combined cycle mode, and less in simple cycle mode for the summer of 2001.

c. One start per day, unless we can agree in the PPA on a charge to compensate MEP for the accelerated and additional associated operating and maintenance expense. MEP will also need an annual cap on the number of starts.

d. Ability of MPS to pre-schedule different hourly values over the schedule, subject to equipment operational constraints as determined by the OEM and EPC contractors, and the air permit. This obviously affects the heat rate (discussed below).

e. Ability of MPS to change the schedule in the event MPS loses a resource serving its' native load, including economy energy resources. Schedule changes by MPS would be made consistent with the scheduling requirements of the Southwest Power Pool reserve sharing program, in which reserves are provided through the end of the next half hour. MEP would therefore receive between 31 and 59 minutes' notice of any schedule change, and MPS would therefore receive the additional power at the end of that period to replace the SPP reserves, subject to the generating equipment being on line.

f. We have your request for Automatic Generation Control under review, and want to have further discussions with MPS to resolve this item.

3. Emission Allowances. Per our discussion on January 4 concerning Article 7 of the draft PPA, any emission allowances required to supply energy from the plant to MPS will be provided for by MPS.

4. Part-load heat rate curves -- Estimated values are provided. These are necessarily subject to final selection of the OEM, associated final cycle design, and assumed heat rate degradation between scheduled maintenance.

5. Minimum load requirements -- Estimated values for both simple and combined cycle operation, as expected to be constrained by the Missouri air permit, are (a) ~105 MW

net for simple cycle operation (one combustion turbine on line); (b) ~105 MW net for one combustion turbine on line with heat rejection to the condenser, which is not a normal operating condition; (c) ~155 MW net in combined cycle operation with one combustion turbine on line and steam from the HRSG to the steam turbine; and (d) ~318 MW net in combined cycle operation with both combustion turbines on line and steam from the HRSG to the steam turbine. These estimates are based on a 99°F summer day.

Other issues can be negotiated next week if MEP is awarded the supply contract. Should you have any questions, please do not hesitate to call.

Very truly yours,

Max A. Sherman

Max Sherman
Project Manager

Enclosure

cc: V.J. Horgan
Joe Gocke
Rob Freeman
Becky Sandring
John McKinney

Estimate

Estimated Heat Rates -- "F" Technology Turbines (2x1)

EPC Guaranteed Values -

From B+V Revised bid dated 11/30/98

	99F Unfired	54F Unfired
Net Power (kw)		
GE	464,700	498,220
Westinghouse	486,460	518,110
Advantage W =	21,760	19,890
Net HR (btu/Kwhr) HHV		
Westinghouse	6,971	6,951

Part Load Heat Rates -

Percent Plant Load	100%	90%	80%	70%	60%	50%	40%	30%	20%	
(From B+V performance curve 12/11/98 TYPICAL) HR Adjustment Factor	1	1.015	1.045	1.08	1.12	1.185	1.065	1.16	1.32	
99F Unfired - Westinghouse	7041	7146	7356	7609	7886	← 1% Degradation				
Heat Rate (btu/kwhr)	6,971.0	7,075.6	7,284.7	7,528.7	7,807.5	8,260.6	7,424.1	8,086.4	9,201.7	← New & Clean
Load (kw)	486,460	437,814	389,168	340,522	291,876	243,230	194,584	145,938	97,292	
54F Unfired - Westinghouse	20	20.3	20.9	21.6	22.4	← 1% Degradation				
Heat Rate (btu/kwhr)	6,951.0	7,055.3	7,263.8	7,507.1	7,785.1	8,236.9	7,402.8	8,063.2	9,175.3	
Load (kw)	518,110	466,299	414,488	362,677	310,866	259,055	207,244	155,433	103,622	

NOTE: The air permit is expected to limit sustained operation of each CT to about 65% load except for startups. Management of this operating constraint will modify the above values.

Merchant Energy Partners
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
816-936-8712
Fax: 816-936-8724
Pager: 800-431-7491

AQUILA ENERGY

January 12, 1999

Max A. Sherman
Senior Director
Origination

Mr. Frank A. DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, Missouri 64138

Subject: Power Supply RFP for Missouri Public Service (MPS)

Dear Frank:

This letter follows up on discussions between MPS and Merchant Energy Partners (MEP) personnel on January 8, 1999 and your e-mail to me on January 11 on certain transmission issues. We are also choosing to enhance our proposal, as provided below, with the expectation that there won't be another round where bidders will be given another opportunity to revise their proposals.

We also wish to advise that MEP has taken a number of steps to advance our project, since our formal proposal was submitted, to assure timely completion. These include, but are not limited to:

1. We have signed an agreement to purchase the plant site near Pleasant Hill, Missouri. Closing on the transaction is scheduled for Friday, January 15, 1999.
2. MEP has filed the air permit application with the Missouri Department of Natural Resources/Air Quality Division. We expect approval in early June. Approval at the end of the statutory review period does not impact our planned date for issuing a Final Notice to Proceed to the EPC contractor.
3. MEP expects to have a signed Memorandum of Understanding, within the next few days, with our chosen EPC contractor.
4. Similarly, MEP expects to have a letter of intent within the next 2 or 3 weeks with our selected combustion turbine manufacturer, including a committed reservation payment for equipment supply. You will note in Section II.A below that we have provided MPS a cap on combustion turbine prices.

With regard to the issues you have identified in the last few days, we have the following responses:

I. MPS Questions on Transmission Upgrades.

Under the section titled "Delivery Points", the proposal states " The proposal includes a cost of $5,560,000 to make the transmission upgrades required to interconnect .....".

A. What upgrades are included in the $5.6 M figure?

Response: Based on discussions with MPS Transmssion, MEP included $3.56 million of "contribution in aid of construction" in the capacity price to assist MPS in completing a new 161 kV circuit from Pleasant Hill to Belton South as the preferred system upgrade. MEP understands this upgrade will significantly improve the MPS 161 kV system in addition to the 69 kV system in the northern Cass County area.

B. Does the $5.6 M figure include the cost of connecting your proposed facility to the MPS substation at Pleasant Hill?

Response: Yes. The cost to expand the existing 161 kV substation and interconnect the proposed 500 MW plant (from the high side of the step up transformer) to the MPS system has been estimated by MPS Transmission to be $2 million. This cost is included in the capacity price as bid, and is part of the $5.6 million cited above. The interconnect costs have been estimated conservatively, but are not firm at this time.

C. What is the impact on the quoted capacity price in $/kW-mo. of the $5.6 M figure?

Response: Per our conversation late yesterday, the impact should refer to $3.56 million of system upgrade costs. That comprises $0.20/kW-month in the capacity price. If system upgrades will be paid for by MPS without the contribution in aid of construction, the capacity price will be reduced accordingly.

II. Risk Mitigation and Value Enhancement

With the revisions noted below, MEP has mitigated certain risks which MPS has identified in our discussions over the last week; these revisions have significantly increased the value of our proposal:

A. <u>Capacity price contingent on combustion turbine pricing.</u> MEP hereby revises our December 22 , 1998 letter, Answer 1 to Question 1. Combustion turbine pricing in our contract with MPS shall not exceed a $0.5 million/turbine increase over the quoted $32,000,000 price. Pricing of that equipment will therefore use the $32,000,000 price (including rail or truck freight from the factory but excluding taxes and the heavy haul from the rail siding to the plant), all as described in our December 22 letter, with any price adjustments to MPS for that scope capped at $0.5 million/turbine.

A. Commitments on In-Service Date. MEP will commit to a June 1, 2001 in-service date for the combustion turbines if MEP and MPS can agree on the dates for : (1) MPS award to MEP; (2) execution of the Power Purchase Agreement; (3) filing date by MPS for its request with the Missouri Public Service Commission for approval of the PPA, and (4) date for obtaining such approval;. If MEP fails to meet the June 1, 2001 date for reasons unrelated to items (1) through (4) above, MEP will pay MPS liquidated damages in the amount of $10,000/day, in addition to suspension of the capacity payment until simple cycle project completion, for the duration and to the extent (e.g., pro rata) simple cycle capacity is not provided to MPS.

C. Deadline for Corporate Approvals. Please be advised we have obtained Aquila Energy senior management approval for this transaction. Board of Directors approval is scheduled for February 4, 1999.

D. Heat Rate Guarantees. MEP offers to pass through to MPS the benefits of our negotiation with the OEM, less a degradation allowance. MEP will be able to offer definitive heat rate guarantees when we've locked in equipment supply from the selected manufacturer. We're talking about equipment coming off a very limited number of production lines, with very close heat rate curves from the major OEMs, so we don't see this as a substantive issue.

E. Reduction in Minimum Schedules taken by MPS. MEP is willing to consider lowering the minimum schedule taken by MPS, which we believe to have significant value to MPS. However, an initial review of the matter indicates there is a cost to MEP for allowing this flexibility, for which we'll need some offsetting compensation or value. We suggest a meeting to discuss this at your convenience. If we can make this work, it will require that MEP retain the right to supply power to MPS from off-system resources, in order to minimize the risk transferred from MPS to MEP.

   Additionally, MEP would enjoy discussing with you the opportunity to provide additional value to MPS by providing the Fixed Fuel Capacity Reservation and associated transportation required to support your schedule.

F. Reduction in capacity price. MEP hereby reduces its capacity price, for the term of the PPA and in addition to the reduction identified in Item I.C above associated with transmission system upgrades, by thirty cents per kilowatt-month ($0.30/kW-month).

Capacity pricing is therefore, including the transmission-related price adjustment identified above, as follows:

Term	Quantity	Capacity Price
June 1, 2001 through September 30, 2001	320 MW	$5.70/kW-month
January 1, 2002 through May 31, 2005	200 MW	$5.90/kW-month
April 1, 2002 through September 30, 2002	300 MW	$7.50/kW-month
April 1, 2003 through September 30, 2003	300 MW	$7.50/kW-month
April 1, 2004 through September 30, 2004	300 MW	$7.50/kW-month
April 1, 2005 through May 31, 2005	300 MW	$7.50/kW-month

In sum, our revised pricing reflects a $0.50/kW-month reduction across the board, including the $0.20/kW-month transmission price reduction described in Section I.C above.

Other issues can be negotiated when MEP is awarded the supply contract. We look forward to bringing the bidding process to a prompt conclusion. Should you have any questions, please do not hesitate to call.

Very truly yours,

Max Sherman

Max Sherman
Project Manager

January 15, 1998

Mr. Max A. Sherman
Merchant Energy Partners
10750 East 350 Highway
Kansas City, MO 64138

Subject: **Merchant Energy Partners Proposal**

Dear Max:

The purpose of this letter is to inform you that the Merchant Energy Partners' (MEP) proposal of November 30, 1998 (including the revisions of December 17 & 22, 1998 and January 6, 7, & 12, 1999) has been selected as the preferred supply side resource in Missouri Public Service's (MPS) 1998 Integrated Resource Planning Process.

UtiliCorp Power Services (UPS) wishes to enter into final contract negotiations on behalf of MPS as soon as MEP is prepared to do so.

Please be advised that the final contract between MPS and MEP is subject to approval by both the Missouri Public Service Commission and the Federal Energy Regulatory Commission.

Should you have questions, feel free to contact me at (816) 936-8639.

Sincerely,

Frank A. DeBacker
Vice President, Fuel & Purchased Power

c: Robert W. Holzwarth
John W. McKinney

bcc: Robert K. Green

Rcvd ~3 PM 1/20/99

Merchant Energy Partners
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
816-936-8712
Fax: 816-936-8724
Pager: 800-431-7491

AQUILA ENERGY

January 20, 1999

Max A. Sherman
Senior Director
Origination

Mr. Frank A. DeBacker
Missouri Public Service
10700 East 350 Highway
Kansas City, Missouri 64138

Subject: Proposed power supply contract for Missouri Public Service (MPS)

Dear Frank:

This letter acknowledges receipt of your letter of January 15, 1999, advising that Merchant Energy Partners' proposal has been selected as the preferred supply side resource, and also expressing the wish to enter into final contract negotiations as soon as MEP is prepared to do so.

Enclosed please find a Power Sales Agreement that we propose be the basis for final negotiations. Two versions are provided – a blackline comparison against the rough, unscrubbed draft provided December 24, 1998, and a clean version. Please be advised that certain appendices will need to be developed; I anticipate this to be a joint effort.

Per previous conversations, MEP proposes to start negotiations on January 25, 1999, in Raytown. Would you please advise, at your earliest convenience, if this date is acceptable.

Very truly yours,

Max A. Sherman

Max Sherman
Project Manager

cc: V.J. Horgan
Steve Arnold
Joe Gocke
Rob Freeman
Dave Kreimer
Becky Sandring
John McKinney
Laurie Hamilton

Aquila Energy
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138

AQUILA ENERGY

February 8, 1999

Mr. Frank DeBacker
UtiliCorp Power Services
10750 East 350 Highway
Kansas City, MO 64138

Dear Frank:

Thank you for your time last week to discuss the terms and conditions in the draft purchases power agreement between Aquila Energy Marketing Corporation and Missouri Public Service. Based on that meeting, AMEC proposes the following changes to the draft agreement.

- Replace Section 2.1.1 (a) with;
  Transmission Service Agreements. Complete execution of final contractual arrangements for the delivery of power from Batesville Unit #1 to MPS within 90 days following the Regulatory Approval Date.
- Replace Section 5.2 with;
  Energy Charge. The price for all energy delivered by AEMC to MPS under this Agreement is $100.00 MWh plus the actual cost of transmission losses and ancillary services for the delivery of power to MPS for the specified firm path from Batesville Unit #1 to MPS as set forth in Section 5.5. In addition, for each start-up of the Designated AEMC Resource requested by MPS, MPS shall reimburse AEMC for a pro-rata share of start-up costs. Such reimbursement shall equal MPS's pro-rata share of AEMC's actual cost for 3,000 MMBtu of natural gas at the time of each start-up.
- Replace Section 7 with;
  Transmission Service. AEMC shall request firm transmission service from Batesville Unit #1 across the Entergy System to Ameren, and across the Ameren System to MPS, to supply the capacity and associated energy from Batesville Unit #1 to the Points of Delivery under this Agreement. In the event Entergy or Ameren refuse AEMC's request for firm transmission service, AEMC shall evaluate alternative firm transmission paths. If an alternative path can be obtained, AEMC shall purchase the path.

If AEMC is unable to obtain firm transmission service from Batesville Unit #1 to MPS by the date provided in Section 2.1.1 (a), either party may at its sole discretion terminate this Agreement. The cost of transmission service shall be billed to and reimbursed by MPS as provided in Section 5.5.

- All references to Aquila Power Corporation, Aquila, APC, etc. will be changed to AEMC.
- All the headings are titled as "ARTICLE" but are referred to as Sections in the text. All headings will be retitled as SECTION 1, SECTION 2, etc.

Please contact me as soon as possible to discuss these proposed changes.

Sincerely,

Mike Jonagan

Mike Jonagan
Regional Director, Power Marketing

cc: V. J. Horgan
R. Freeman
T. Wertz

POWER SALES AGREEMENT

BETWEEN

MEP PLEASANT HILL, LLC

AND

UTILICORP UNITED INC. d/b/a MISSOURI PUBLIC SERVICE

dated
February 22, 1999

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Appendix A - Metering and Testing
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POWER SALES AGREEMENT
BETWEEN
MEP PLEASANT HILL, LLC
AND
UTILICORP UNITED INC. d/b/a MISSOURI PUBLIC SERVICE

THIS AGREEMENT, is made and entered into this 22nd day of February, 1999, by and between MEP Pleasant Hill, LLC, a limited liability company organized under the laws of Delaware engaged in the business of generating and purchasing electric power and energy for sale to other entities, having its principal office and place of business at 10750 East 350 Highway, Kansas City, Missouri 64138 (hereinafter referred to as "Project Company"), and UTILICORP UNITED INC. d/b/a Missouri Public Service, a Delaware corporation having its principal office and place of business at 20 West Ninth Street, Kansas City, Missouri 64105 (hereinafter referred to as "MPS"), Project Company and MPS being individually and collectively referred to as, respectively, Party or Parties.

WITNESSETH:

WHEREAS, MPS desires to purchase:

320 megawatts (net) of capacity and associated energy for the period June 1, 2001 through September 30, 2001;

200 megawatts (net) of capacity and associated energy for the months of January through March for the years 2002 through 2005 and the months of October through December for the years 2002 through 2004; and

500 megawatts (net) of capacity and associated energy for the months of April through September in the years 2002 through 2004 and for the months of April and May in the year 2005;

in all cases on the terms and conditions specified in this Agreement;

WHEREAS, Project Company desires to sell unit capacity and associated energy from a generating station (the "Missouri Generator") to be constructed near Pleasant Hill, Missouri, on property owned by Project Company, such unit to operate in a simple cycle mode during the year 2001 and in combined cycle mode on and after January 1, 2002; and

WHEREAS, it is intended that, as provided herein, unless otherwise agreed, MPS will arrange for the supply of natural gas to the Missouri Generator for MPS's electric energy requirements from the Missouri Generator and the power and energy from the Missouri Generator will be delivered by Project Company to MPS at the Interconnection Point;

NOW THEREFORE, in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties hereto mutually contract and agree as follows:

ARTICLE 1 -- DEFINITIONS

The following terms shall have the respective meanings set forth below:

1.1 Agreement. Agreement means this Power Sales Agreement, including, when applicable, any amendments and exhibits hereto, that the Parties may execute now or at any time in the future.

1.2 Billing Month. Billing Month means the period beginning on the first day and extending through the last day of each calendar month during the term of this Agreement.

1.3 Business Day. Business Day means any week day other than weekdays designated as holidays by the North American Electric Reliability Council (or its successor).

1.4 Commercial Operation Date (COD). Commercial Operation Date (COD) shall mean, as to each generating unit of the Project, and separately in simple cycle and combined cycle mode, the first date on which such unit, in the reasonable opinion of Project Company, is capable of producing and the Project is capable of delivering electric energy for sale to MPS pursuant to the terms and conditions of this Agreement or, in the alternative, Project Company declares that it is ready to provide equivalent service from alternative resources.

1.5 Contract Year. Contract Year shall mean the period commencing on the COD of the first unit and expiring at midnight on May 31, 2002, and each subsequent twelve-month period.

1.6 Contract Capacity. Contract Capacity shall mean 320 MW during 2001, 200 MW from January 1 through March 31 for each of 2002 through 2005 and October 1 through December 31 for each of 2002 through 2004; and 500 MW from April 1 through September 30 of 2002, 2003 and 2004 and from April 1, 2005 through May 31, 2005.

1.7 Electrical Interconnection Agreement. An agreement with a term of at least thirty (30) years between MPS and Project Company delineating the responsibility of each for design, construction, ownership, maintenance, and operation of the facilities necessary for the interconnection of the Missouri Generator to the MPS transmission system and any transmission facility upgrades or reinforcement to be installed in connection therewith; setting out the terms and conditions of interconnected operations on a firm First Contingency Incremental Transfer Capability basis, including, without limitation, incorporation by reference of the rules and practices of the SPP; and satisfying the criteria set out in Appendix B.

1.8 Equivalent Availability. Equivalent Availability shall have the meaning as described in Section 5.3 below.

1.9 Event of Default. Event of Default shall have the meaning as described in Section 13.1.

1.10 FERC. FERC shall mean the Federal Energy Regulatory Commission, or any successor to its functions and responsibilities related to this Agreement.

1.11 Interconnection Point. Interconnection Point shall mean the point of interconnection between MPS and the Project, shown on Appendix B.

1.12 Month. Month shall mean a calendar month.

1.13 MPSC. MPSC shall mean the Missouri Public Service Commission, or any successor to its functions and responsibilities related to this Agreement.

1.14 Planned Outage. Planned Outage shall mean an outage of the Missouri Generator or of a major component thereof to perform major or annual maintenance and that is scheduled during the preceding year. There shall be no Planned Outage in the months of June through September. MPS must be informed at least ninety (90) days in advance of Planned Outage.

1.15 Project. Project shall mean, at any stage of development, construction, or operation the Missouri Generator, together with all water rights, water transportation and treatment facilities, fuel receipt facilities and interconnection facilities (in each case owned by the owner of the Missouri Generator), associated rights in real property, rights-of-way, and contractual rights.

1.16 Prudent Industry Practices. Prudent Industry Practices shall mean any of the practices, methods, standards and acts (including, but not limited to, the practices, methods and acts engaged in or approved by a significant portion of the independent power generation industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance standards recommended by a facility's equipment suppliers and manufacturers, applicable facility design limits and applicable governmental approvals and law.

1.17 Rated Capability. Rated Capability shall mean the capability of the Missouri Generator, as such capability is determined from time to time by Project Company or the operator of the Project pursuant to the requirements of the SPP in effect from time to time and Prudent Industry Practices.

1.18 Scheduled Maintenance. Scheduled Maintenance shall mean a derate or full outage of the Missouri Generator or any major component thereof that is necessary to carry out maintenance (other than a Planned Outage) consistent with Prudent Industry Practices and which if not carried out prior to the next scheduled maintenance period could result in a forced outage, a reduction in performance (other than heat rate degradations) or reliability, or significant damage to the Missouri Generator or a major component thereof. Scheduled Maintenance shall be scheduled per Section 4.2.2. A Scheduled Maintenance is neither a Planned Outage nor a forced outage.. Scheduled Maintenance hours shall be included in equivalent planned derate hours for the purpose of Section 5.3. To the extent possible, Scheduled Maintenance shall be scheduled for the hours from 11 p.m. to 7 a.m. the following day, or on a Saturday or Sunday.

1.19 SPP. SPP shall mean the Southwest Power Pool or any successor or alternative thereto of which MPS is a member.

1.20 Summer Period. Summer Period shall mean the period from April 1 through September 30, or any part thereof during which service is to be provided under this Agreement.

1.21 Taxes. Taxes shall mean any or all ad valorem, property, occupation, severance, generation, first use, conservation, Btu or energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments, other than taxes based on net income or net worth. "New Taxes" means (i) any Taxes enacted and effective after the effective date of this Agreement, including, without limitation, that portion of any Taxes or New Taxes that constitutes an increase, or (ii) any law, rule, order or regulation, or interpretation thereof, enacted and effective after the effective date of this Agreement resulting in the application of any Taxes to a new or different class of Parties. "Reduced Taxes" means (i) any Taxes enacted and effective after the effective date of this Agreement, including, without limitation, that portion of any Taxes or New Taxes that constitutes a decrease, or (ii) resulting in the exclusion or exemption from the application of any Taxes to a new or different class of Parties.

1.22 Winter Period. Winter Period shall mean the period from January 1 through March 31 and October 1 through December 31 of each year, or any part thereof during which service is to be provided under this Agreement.

ARTICLE 2 - TERM OF AGREEMENT

2.1 Effective Date. The effective date of this Agreement shall be the date this Agreement has been executed by both Parties.

2.1.1 Conditions Precedent. The following shall be conditions precedent to the obligations of the Parties hereunder to purchase or sell capacity and energy:

(a) MPSC approval. Final approval by the MPSC of this Agreement upon terms satisfactory to both Parties by July 1, 1999.

(b) FERC Acceptance. FERC approval of Project Company's application for Exempt Wholesale Generator status for Project Company and FERC action making this Agreement, or permitting this Agreement to become, effective without modifications that are unacceptable to either Party by the earlier of a date that is ninety (90) days after approval by the MPSC or September 1, 1999.

(c) Approval of the Board of Directors of Project Company's parent company, UtiliCorp United Inc., for Project Company or an affiliate to develop, own, and construct the Project and for MPS to participate in this Transaction by February 5, 1999.

(d) Electrical Interconnection Agreement. Execution of the Electrical Interconnection Agreement incorporating the provisions of Section 5.1(b) and FERC action making it, or permitting it to become, effective without modifications that are unacceptable to either Party by September 1, 1999.

(e) Site Acquisition. Acquisition of all necessary rights-of-way with respect to the Project site by September 1, 1999.

(f) EPC Contract. Execution of a contract for the engineering, procurement, and construction ("EPC") of the Missouri Generator on commercially reasonable terms by August 1, 1999; and issuance by Project Company of a notice to proceed to the EPC contractor by September 1, 1999.

(g) Turbine Purchase. Purchase of the combustion turbines, for the Missouri Generator on commercially reasonable terms by March 15, 1999.

(h) Water Supply and Permits. Securing by Project Company of rights to acquire sufficient water for the project in combined cycle mode for its useful life and rights of way to transport the water to and from the Project site, in both cases under commercially reasonable terms, and issuance of all necessary permits for such water use by September 1, 1999.

(i) Air Permit. Issuance of all necessary air permits to Project Company or, to the extent necessary or appropriate, securing of allowances or offsets to permit the operation of the Missouri Generator in a manner reasonably estimated by Project Company by September 1, 1999.

(j) Construction Permits. Issuance of any necessary zoning adjustments or variances and of all necessary permits for construction of the Missouri Generator.

(k) Gas Interconnection Agreements.

(i) Execution of a gas interconnection agreement on commercially reasonable terms with the interstate pipeline (or local distribution company) selected in accordance with Section 5.1(c) and issuance of all necessary regulatory approvals therefor by September 1, 1999;

(ii) Securing of necessary zoning, rights of way, and construction permits for gas delivery and transportation facilities on the Project site and to the interstate pipeline selected in accordance with Section 5.1(c) on commercially reasonable terms by September 1, 1999; and

(iii) Execution of EPC contract for the gas delivery and transportation facilities on commercially reasonable terms by September 1, 1999.

2.1.2 Agreement to Fulfill Conditions. Project Company and MPS agree to utilize best, commercially reasonable efforts to fulfill each of the conditions listed above which is incumbent upon them to satisfy and shall notify the other Party in writing when each condition is satisfied. Each Party shall cooperate with the other in attempting to satisfy the conditions.

2.1.3 Failure of Condition Precedent. In the event that any of conditions in Section 2.1.1, above has not been satisfied by the date specified therein, either Party may terminate this Agreement by giving notice to the other Party in writing. All conditions in 2.1.1 above will be deemed to occur upon financial close and distribution of lending proceeds to Project Company.

2.1.4 Effects of Termination. In the event that this Agreement is terminated pursuant to this Section 2.1, then neither Party shall have any other obligation to the other under this Agreement.

2.2 Termination Date. The provisions of this Agreement shall continue in effect through May 31, 2005, unless extended by mutual agreement of the Parties or earlier terminated pursuant to Section 2.1, or Article 13.

2.3 MPS Termination and Capacity Reduction Options.

MPS will have the ability to purchase within 30 days of executing this Agreement any one of the four alternatives, listed below, which will give MPS the right to purchase an option to reduce its contractual obligations to purchase some or all of the capacity (and associated energy) covered by this Agreement. The following alternatives are available to MPS for

30 days after execution of this Agreement. The alternatives have the following expiration dates and costs payable within 30 days of executing this Agreement if elected:

Expiration Date		Cost of Alternative
A:	June 1, 1999	$630,000
B:	December 1, 1999	$1,260,000
C:	June 1, 2000	$1,890,000
D:	December 1, 2000	$2,520,000

MPS may purchase any of the above alternatives for a portion of capacity less than the Contract Capacity. The Cost for such a portion will be determined on a pro rata basis. MPS is not obligated to choose any of the above alternatives. If so elected any of the above alternatives grants MPS the right to select a Termination Option on or before the Expiration Date. The Termination Option provides the opportunity for MPS to purchase for $0.90 per kW month on the lower of Contract Capacity or Rated Capability the option to reduce its contractual obligations covered by this Agreement. If the Termination Option is elected MPS agrees to pay the Project Company $0.90 per kW month of the lower of Contract Capacity or Rated Capability for each of the 36 months commencing from June 1, 2002 to May 31, 2005 for the right to terminate the Agreement or to reduce its purchase obligation by blocks of twenty-five (25) MW for the Summer Period and ten (10) MW for the Winter Period. MPS agrees to pay the $0.90 per kW month fee irrespective of whether it chooses to exercise the Termination Option. The termination and capacity reduction option may be exercised only on June 1, 2002, June 1, 2003 or June 1, 2004 and shall be exercised by MPS by written notice not later than March 1 preceding the June 1 at which the termination or capacity reduction becomes effective. On the June 1 on which the termination or capacity reduction becomes effective, MPS shall make a one-time lump-sum payment to the Project Company equal to the product of $0.90 per kW month and the capacity reduction (or in the case of termination the lower of Contract Capacity or the highest Rated Capability during the preceding twelve (12) months) for each month from the day of payment until May 31, 2005, and shall then have no further liability with respect to the capacity reduction or this Agreement, as the case may be for the specified capacity.

If MPS does not elect any of the four alternatives listed above, the Project Company agrees to price such an option at any future date if so requested in writing by MPS.

ARTICLE 3 - CAPACITY AND ENERGY TO BE PURCHASED AND SOLD

3.1 Generating Capacity and Energy. Subject to the other provisions of this Agreement, Project Company agrees to sell and MPS agrees to purchase generating capacity in the amount of three hundred twenty megawatts (320 MW) during the simple cycle phase from June 1, 2001 through September 30, 2001; and, during the combined cycle phase, two hundred megawatts (200 MW) from January 1, through March 31, for each of 2002 through 2005 and October 1 through December 31 for each of 2002 through 2004; and five hundred megawatts (500 MW) from April 1 through September 30 in the years 2002, 2003, and 2004 and from April 1 to May 31 in the year 2005, plus, in all cases, energy scheduled in accordance with Article 6. Title to the energy shall pass from Project Company to MPS at the Interconnection Point (or, in the case of substitute energy, at the delivery point to the MPS transmission system) for the term of this Agreement. Capacity and energy from the Missouri Generator shall both be measured at the Interconnection Point, adjusted such that losses between the busbar and the Interconnection Point shall be for the account of MPS.

Notwithstanding the provisions of Article 4 and subject to the provisions of Article 6, Project Company may, at its sole discretion, substitute in whole or in part energy from other resources for energy from the Missouri Generator, so long as that energy is delivered to an interconnection of MPS with another utility or independent generator, and so long as the alternate delivery point has adequate capacity to receive such energy. In this case, the measurement of energy shall be based on the schedule for delivered quantities from the alternative source and/or the transmitting utility. Project Company shall reimburse MPS for any penalties MPS has to pay for failure to take natural gas or utilize natural gas transportation when MPS has committed to gas purchases or transportation consistent with the dispatch schedules it provides to Project Company, when such penalties are directly caused by Project Company's decision to supply electricity from an alternative source rather than from the Missouri Generator; provided, however, that MPS shall (i) make all reasonable efforts to mitigate such penalties, (ii) upon request by Project Company, promptly provide Project Company with good-faith estimates of the penalties involved if Project Company were to supply some or all of the electricity scheduled by MPS from alternative sources, and (iii) upon notification by Project Company that it intends to supply electricity to MPS from alternative sources in a specified amount for a specified period, refrain from making further commitments for the purchase or transportation of natural gas to generate electricity in those amounts and for that period that would be the basis for penalties.

3.2 Delayed COD; Liquidated Damages. If the Project Company has not achieved COD for both combustion turbine units in simple-cycle operation by June 1, 2001, the Project Company will pay to MPS as liquidated damages five thousand dollars ($5,000) per combustion turbine unit per day of delay; provided, however, that Project Company may provide MPS with substitute capacity and energy (to the extent dispatched, and subject to Section 6.3) from other sources, in which case the liquidated damages will apply ratably to the extent that Project Company provides less than 320 MW of available capacity in any day; and provided, further, that there shall be an extension of the June 1, 2001 date for a period equal to the extent of the delay caused the Project Company by one or more Force Majeure events or by the failure of MPS or the Parties to satisfy the following milestones:

(a) Filing of the application for approval of this agreement with the Missouri Public Service Commission by the Parties by March 1, 1999;

(b) Issuance of an order of the MPSC approving this agreement by July 1, 1999; and

(c) Access by Project Company to MPS's substation for the purpose of effecting interconnection by September 30, 2000, and completion by MPS of any transmission facilities reinforcement or upgrades necessary to permit synchronous operation of the full contract capacity of the Missouri Generator on MPS's system by December 31, 2000.

Notwithstanding the provisions of Article 13, these liquidated damages shall be the exclusive remedy for MPS for Project Company's failure to meet the scheduled COD for the combustion turbines in simple-cycle mode. Such failure is not an Event of Default under Article 13, and MPS may not terminate this agreement for such failure.

3.3 Deemed COD. In the event that delays in achieving the milestones set out in Section 3.2 cause delays in the construction or testing of the Project in either simple cycle or combined cycle operation such that the COD occurs after June 1, 2001 and/or January 1, 2002, respectively, MPS shall begin paying the Capacity Charges for the appropriate period at the Contract Capacity for such period, all as set out in Section 5.1, on June 1, 2001 and/or January 1, 2002, as the case may be; provided, however, that this provision shall apply only if and to the extent that, absent such delay in the achievement of the milestones, Project Company could reasonably have been expected to achieve COD by June 1, 2001 and/or January 1, 2002 and such delay reasonably prevents Project Company from achieving COD by June 1, 2001 or January 1, 2002, as the case may be. If COD would not reasonably have been expected to occur by those dates, but the failure to achieve the milestones caused an additional delay, then this provision will apply only to the additional delay caused by the failure to achieve the milestones. If, following actual testing and COD, the Rated Capability is less than the Contract Capacity, Project Company will refund to MPS the overpayment with interest calculated in accordance with Section 17.5. Any dispute between the Parties over whether and to what extent payments under this Section 3.3 are due shall be resolved under the procedures set out in Article 16.

ARTICLE 4 - CURTAILMENT OF CAPACITY AND ENERGY

4.1 When Curtailable. Capacity and energy from the Missouri Generator for supply of generating capacity shall be continuously available from the Minimum Generation level at any given time as set out in Appendix D - Operating Limits, up to the full Rated Capability, (but not to exceed the Contract Capacity), subject to the ramp rates and other Operating Limits set out in Appendix D, except that it may be curtailed at the option of Project Company (subject to Section 5.3) in the event of the occurrence of any or all of the following, as determined by Project Company in accordance with Prudent Industry Practices:

4.1.1 Equipment Failure. Equipment failure requiring reduced operation or shutdown of the Missouri Generator for the supply of generating capacity; or

4.1.2 Inspection. Inspection requiring reduced operation or shutdown of the Missouri Generator for the supply of generating capacity; or

4.1.3 Maintenance or Repair. Maintenance or repair requiring reduced operation or shutdown of the Missouri Generator for the supply of generating capacity; or

4.1.4 Unavailability of Fuel. Limitations on the ability of the operator to operate the Missouri Generator in part or in whole due to fuel consistent with the quality parameters identified in Appendix C not being made available to the Missouri Generator for any reason; or

4.1.5 Transmission Limitations. Transmission limitations on MPS's system affecting MPS' ability to receive the power and energy at the Point of Interconnection as required to implement this Agreement; or

4.1.6 Force Majeure. Force Majeure events as defined in Article 12 hereof; or

4.1.7 Derate. Derate (defined as a reduction in the Rated Capability) of the Missouri Generator for the supply of generating capacity for any cause other than equipment failure, inspection, maintenance, repair, Force Majeure, or unavailability of fuel.

4.2 Additional Curtailment Provisions:

4.2.1 Effect of Curtailment. When capacity is curtailed pursuant to Section 4.1 hereof, the generating capacity shall be reduced by no more than the ratio of the unavailable capacity to the Rated Capability of the Missouri Generator. When the condition leading to curtailment is removed, generating capacity shall be restored to precurtailment levels.

4.2.2 Notice. To the extent practicable, Project Company shall supply MPS reasonable advance notice of all curtailments and interruptions of contracted for capacity and energy under this Agreement, and for Scheduled Maintenance shall provide the following notice: for an outage of less than two (2) days' expected duration, at least twenty-four (24) hours' notice to MPS; for an outage of two to five days' expected duration, at least seven days' notice; and for an outage of five days' or more expected duration, at least ninety (90) days' notice, unless, in each case, MPS has given its permission for shorter notice.

4.2.3 Missouri Generator Performance. Project Company shall operate, maintain and restore, either directly or through its agent and operator, the Missouri Generator in accordance with Prudent Industry Practices.

4.2.4 Other Resources. When delivery of generating capacity or energy to MPS from the Missouri Generator is curtailed as set forth above, Project Company shall have the right but not the obligation to deliver generating capacity or energy from any other resource subject to Section 5.2.

ARTICLE 5 - PRICE FOR CAPACITY AND ENERGY

5.1 Capacity Charge. Beginning with the later of COD of the combustion turbines (including deemed COD pursuant to Section 3.3) or June 1, 2001, the Capacity Charge for the generating capacity for the Contract Capacity of 320 MW for each month from June 1, 2001 through September 30, 2001 is $5.70 per kilowatt-month ($5.70/kW-month)(pro-rated for any partial month prior to COD). Beginning with the later of COD of the Project for combined cycle operations (including deemed COD pursuant to Section 3.3) or January 1, 2002, the capacity charge for the Contract Capacity of 200 MW for each month from January 1, 2002 through May 31, 2005, is $5.90 per kilowatt-month ($5.90/kW-month); and for the Contract Capacity of 300 MW for each month from April 1 through September 30 in each of 2002, 2003, and 2004 and from April 1 to May 31, 2005, is $7.50

per kilowatt-month ($7.50/kW-month)(pro-rated as appropriate for any partial month prior to COD), subject in each case described in this paragraph to the following adjustments and limitations:

(a) This pricing is based expressly on the assumption that Project Company can acquire two new "F" class gas turbines each with a nominal power output rating of 160 MW on the stipulated schedule and on terms that are conventional for purchases of this type, including vendor guarantees, warranties, and liquidated damages, for no more than $32 million per turbine (including rail or truck freight from the manufacturer but excluding taxes and the costs of removal from the rail siding to the project site). If the final price is higher than this amount despite all reasonable efforts of Project Company to obtain a lower price, the Capacity Charges will be adjusted pro rata using as a scale an increase of $0.055 per kW-month for a $1 million increase in the equipment price (which adjustment reflects a pro-rating of the additional investment over the useful life of the Project) or Project Company will be compensated in an alternative manner acceptable to Project Company. This adjustment will not apply to any increase in the price of the turbines in excess of five hundred thousand dollars ($500,000) per turbine.

(b) This pricing is based expressly on the assumption that Project Company will have to spend no more than two million dollars ($2,000,000) on the interconnection with MPS at the Interconnection Point and that MPS will be responsible for the costs and implementation of any transmission system upgrades and reinforcements necessitated in whole or in part by the interconnection of the Missouri Generator and any and all other costs on its side of the Interconnection Point, except for that as provided in Appendix B. To the extent that the final cost of interconnection is less than or exceeds this amount, the Capacity Charges will be adjusted in the same manner as set out in (a), above or unless Project Company or MPS, as the case may be, is compensated in an alternative manner acceptable to, as the case may be, Project Company or MPS.

(c) Project Company will construct a gas pipeline header system at its expense connecting the Missouri Generator, either directly or through the local distribution company, to one of the following three interstate pipelines:

Williams, Panhandle Energy, and KNI, as mutually agreed by the Parties. If the Parties cannot agree, Project Company will eliminate one of the three pipelines from consideration, and MPS will select from the remaining two pipelines, subject to the ability of Project Company to arrange for such connection on commercially reasonable terms. The Parties may mutually agree to have Project Company build a second connection to another of the pipelines listed above, in which case the Capacity Charges shall be adjusted in the manner set out in (a) and (b) above for the additional cost of the second connection.

(d) In the event that, after adjustment for any difference in methodology, the Rated Capability is less than the Contract Capacity, the Rated Capability shall be used as the basis for both Capacity Charges and the formula for Equivalent Availability set out in Section 5.3.

5.2 Energy Charge. Unless otherwise agreed by the Parties, all natural gas for operation of the Missouri Generator to supply energy to MPS will be supplied and paid for by MPS. The quantity of natural gas that MPS is required to provide each day to the Project Company is equal to the sum, for each hour, of the energy scheduled by MPS for such hour multiplied by the effective heat rate found in Appendix C for such energy dispatch level. The Energy Charge for all energy delivered by Project Company to MPS under this Agreement is $1.25 per MWh, in 1998 dollars indexed quarterly to the Producer Price Index published by the U.S. Department of Commerce, using as a base value the level of such index on July 1, 1998. In addition, MPS shall provide natural gas for all start-ups of a combustion turbine that is a part of the Missouri Generator, that are requested or caused by MPS, and shall pay in addition the incremental costs, including but not limited to additional maintenance costs, related to start-ups requested or caused by MPS in excess of 175 start-ups per combustion turbine per year. MPS shall not have to pay for natural gas consumed by the Missouri Generator (whether to gas suppliers or, if the Parties agree that Project Company shall purchase gas to generate electricity for MPS, to Project Company) to the extent that the Missouri Generator is operating at higher heat rates (MMBtu (HHV) per MWh) than the guaranteed levels, which are set out in Appendix C. The annual effective heat rates used to calculate allowable usage of natural gas shall be the lower of the actual heat rates, determined from time to time by testing, and the guaranteed heat rates. The heat rates shall also be adjusted for part-load operation using the heat rate curves supplied by the EPC contractor and/or equipment vendor, which initial guaranteed heat rate curves shall be appended hereto in Appendix C. To the extent that Project Company chooses to generate energy at a level which is greater than the level at which it is scheduled pursuant to Section 6.1, in order to make sales to others (other than in the circumstance described in Section 6.2), MPS will be responsible for purchased gas costs only up to the level calculated by multiplying the purchased gas price times the scheduled level of output at the appropriate heat rate for such level of scheduled output as shown in Appendix C. Notwithstanding the foregoing, during periods when Project Company is providing substitute energy, MPS is obligated to pay the Energy Charge plus either (i) provide fuel to the Missouri Generator or, (ii) in lieu of providing fuel, pay to Project Company the equivalent of the avoided purchased gas cost multiplied by the scheduled level of output multiplied by the appropriate heat rate set out in the heat rate curves in Appendix C.

5.3 Guaranteed Minimum Equivalent Availability. Project Company guarantees the Equivalent Availability ("EA"), as defined hereafter, of the energy output of the capacity supplied hereunder shall be not less than ninety-four percent (94%) for each of the period from April 1 to September 30 of the year (or any part of such period during which service is to be provided under this Agreement) (the "Summer Period") and the period comprising January 1 to March 31 and October 1 to December 31 of the year (or any part of such period during which service is to be provided under this Agreement) (the "Winter Period"). The Capacity Charge specified in Section 5.1 above shall be adjusted as provided below based on the EA during any such period:

(i) When EA, as defined below, is less than 94% for any Winter Period, the capacity charge stated above in Section 5.1 for the Winter Period of such year shall be adjusted by multiplying it by the ratio of the actual EA for such period to 0.94.

(ii) When EA, as defined below, is less then 94% for any Summer Period, the weighted average of the capacity charge for the 200 MW block for that year (weighted as two-fifths) and the capacity charge for the 300 MW block for that year (weighted as three-fifths) shall be adjusted by multiplying it by the ratio of the actual EA for such period to 0.94.

Project Company shall pay MPS the difference between capacity payments received in connection with such period and the result of the calculation described above, with interest as provided in Section 17.5, within thirty (30) days of the end of the period.

EA shall be determined as provided below with Contract Capacity subject to Section 5.1(d):

$$EA = (PH - (EUDH + ESMH + EPOH))/PH$$

Where:

EUDH is the number of equivalent unplanned derate hours for the period calculated as the sum of, for each unplanned derate below the applicable Contract Capacity, the product of the number of hours of full or partial derate times the size of the reduction below the applicable Contract Capacity divided by the Contract Capacity for such period. For the purposes of this calculation, an unplanned derate includes forced outages, forced derates, shortages relative to the planned start-up time, shortages relative to the planned ramp rates, and other times when the net electrical output of the Missouri Generator is less than the amount of energy dispatched, excluding unavailability due to Force Majeure events and due to unavailability of natural gas;

ESMH is the number of equivalent planned derate hours including Scheduled Maintenance hours calculated as the sum, for each planned derate below the Contract Capacity applicable during the period, of the product of the number of hours of full or partial derate times the size of the reduction below the applicable Contract Capacity divided by the Contract Capacity for such period. For the purposes of this calculation, a planned derate excludes unavailability due to Force Majeure events and due to unavailability of natural gas and unavailability due to Scheduled Maintenance when and to the extent that MPS has not scheduled the Missouri Generator for energy deliveries during such period;

PH is the number of hours in the applicable period (for example, 2928 (the number of hours from 00:00 hours Central Prevailing Time (CPT) on June 1, 2001 through 24:00 hours CPT on September 30); and

EPOH is the product of the number Planned Outage hours during the period times the difference between the applicable Contract Capacity and available capacity during the Planned Outage (if lower), divided by the lower of the applicable Contract Capacity or the Rated Capability for such period.

For the purposes of calculating EA, Project Company shall receive credit in the calculation for those hours when the output of the Missouri Generator is restricted, when and to the extent Project Company is delivering power and energy to MPS, as scheduled hereunder, from alternate generating resources.

5.4 Exclusive Remedy. The reduction in the Capacity Charge as set forth above and liquidated damages described in Section 3.2 for late COD shall be MPS's exclusive remedy for any failure of Project Company to deliver capacity and/or energy pursuant to this Agreement, and all other remedies are hereby waived.

5.5 No Petitioning for a Change. Project Company and MPS covenant, to each other's mutual benefit, not to initiate, pursue or support any petition or request with any body having jurisdiction, including but not limited to the FERC, for an increase, decrease or other modification of the rate at which capacity and energy are sold hereunder and as may be initially approved by any applicable regulatory authority, if any.

ARTICLE 6 - SCHEDULING

6.1 Routine Scheduling. Subject to the other provisions of this Agreement, in any hour MPS is entitled to schedule and receive energy up to the maximum generating capacity to which MPS is entitled, MPS shall schedule generating capacity and associated energy with Project Company. Schedules for each day shall be made by thirty (30) minutes before the time that the gas suppliers or transporters must be notified on the previous Business Day of orders for gas, unless otherwise agreed by Project Company and MPS. Schedules shall be submitted by MPS to Project Company by facsimile or telephoned instruction to Project Company's designated representative for this transaction. Unless otherwise agreed, the minimum schedule block is as set out in Appendix D, as each level may be adjusted by Project Company to comply with air permit restrictions and Prudent Industry Practices for any hour the power is scheduled. The minimum schedule duration is four (4) consecutive hours for simple cycle operation during 2001 and eight (8) consecutive hours for combined cycle operation. Each day's schedule shall provide no more than one output level per hour, and the changes from one output level to another shall be consistent with Prudent Industry Practices, including but not limited to ramp rates as specified by the equipment manufacturers and the operator as set out in Appendix D; and compliance with the terms of the facility's air quality permit. Unless otherwise provided by written agreement between the Parties that provide for compensation for Project Company for increased operating and maintenance costs consistent with Section 5.2, there shall be no more than one start-up per calendar day and no more than 175 start-ups per combustion turbine per Contract Year, except for the first Contract Year, for which the permitted number of starts is 150, decreased pro rata upon delays in COD.

6.2 Emergency Scheduling. In the event that MPS suffers an unscheduled outage of a generating resource that is serving MPS's native load, including an energy resource the output of which is being purchased by MPS under an economy energy or other purchase arrangement, and MPS immediately notifies Project Company thereof, Project Company will, by the end of the half-hour following the half-hour in which the outage occurred and MPS notifies Project Company of the outage (that is, when the automatic provision of emergency energy from the SPP under its reserve sharing program ends), Project Company shall make available to MPS any capacity and energy not already scheduled for delivery to MPS from units that are on line at the time of such notice up to the Rated Capability. If the outage is expected to extend until the time that a unit not on line at the time of notice of the outage could be brought up, in a manner consistent with Prudent Industry Practices, to serve load, and MPS directs Project Company to bring such unit or units on line, Project Company will also supply MPS from such unit as soon as possible consistent with Prudent Industry Practices. MPS shall reimburse Project Company for the incremental costs of such a start-up. All energy and fuel provided under this section shall be paid for in accordance with Section 5.2.

6.3 Operating Committee. Each Party shall designate in writing two (2) employees as its representatives to the Operating Committee. Each Party can change its representative at any time by written notice to the other Party. The Operating Committee shall meet within forty-five (45) days prior to the expected COD of the first combustion turbine, within forty-five (45) days of the expected COD of the Project in combined cycle mode, and at least every six (6) months thereafter to coordinate the operations of the Parties and develop any written procedures deemed necessary or desirable by the Parties; provided, however, that the members of the Operating Committee shall not have the authority to amend this Agreement or to agree to procedures inconsistent with this Agreement.

ARTICLE 7 - CLEAN AIR ACT EMISSIONS ALLOWANCES

MPS shall provide any and all emissions allowances necessary to operate the Missouri Generator in accordance with the schedules provided by MPS or, if it cannot do so, shall reimburse Project Company for the cost of such allowances.

ARTICLE 8 - BILLING AND PAYMENT

8.1 Timing; Method of Payment. Project Company will render to MPS invoices for all payments or other charges due hereunder on a monthly basis. Invoices for any month will be issued on or before the fifth (5^{th}) day of the following month, and such invoices will be payable by MPS before the twentieth (20^{th}) day of that month or fifteen (15) days after issuance of the invoice, whichever is later, to the credit of Project Company, 10750 East 350 Highway, Kansas City, Missouri 64138. All remittances for payment shall be made in immediately available funds, unless otherwise agreed, and shall be made at the office or bank account as designated by Project Company by wire transfer pursuant to the wire transfer instructions as set forth in Section 15.13.

8.2 Late Payment. Amounts owed by MPS and not disputed, if not remitted within the time period specified under Section 8.1 above, shall be subject to a late payment charge based on the rate of interest calculated as provided in Section 17.5 hereof

8.3 Disputed Billings. In case any portion of an invoice submitted pursuant to Section 8.1 hereof is in bona fide dispute, the undisputed amount shall be payable when due. With each partial payment, MPS shall provide Project Company with its grounds for disputing a bill. Upon determination of the correct amount, the remainder, if any, shall become due and payable with interest, calculated as provided in Section 17.5 hereof, accruing from and after the date such payment would otherwise have been due.

8.4 Adjustments. If any overcharge or undercharge in any form whatsoever shall at any time be found and the statement therefor has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge paid and the Party that has been undercharged shall pay the amount of the undercharge, within thirty (30) days after final determination thereof, provided, however, no retroactive adjustment shall be made for any overcharge or undercharge beyond a period of twenty-four (24) months from the date of the statement on which such overcharge or undercharge was first included.

8.5 Audit Rights. The Parties shall keep complete and accurate records, meter readings and memoranda of their operations under this Agreement and shall maintain such data for a period of at least two (2) years after the completion of each Billing Month hereunder. Either Party shall have the right to examine and inspect all such records, meter readings and memoranda insofar as may be necessary for the purpose of ascertaining the reasonableness and accuracy of all relevant data, estimates, statements or charges submitted to it hereunder.

8.6 Meters. Project Company shall install, maintain, read, and test metering devices to measure the electrical output for sale to MPS, all in accordance with Appendix A hereto. When Project Company is selling electricity from the Missouri Generator to MPS and to one or more other buyers at the same time, the electrical output shall be allocated first to MPS, until the full scheduled deliveries are made, with any surplus allocated to the other transaction or transactions. Natural gas delivered on MPS's behalf to Project Company for generation of electricity for MPS shall be measured in accordance with Appendix A.

ARTICLE 9 - TAXES

Any New Taxes imposed on Project Company in connection with the sale of capacity and energy to MPS hereunder or the provision of fuel supply used to generate the energy sold hereunder shall be reimbursed to Project Company by MPS unless Project Company should reasonably have known of such New Taxes on January 25, 1999. Any Reduced Taxes to the benefit of Project Company will be passed through as and when realized by Project Company to MPS, unless MPS should reasonably have known of such Reduced Taxes on January 25, 1999.

ARTICLE 10 - INDEMNIFICATION; LIMITATION OF LIABILITY

10.1 Indemnification. Each Party shall indemnify, save harmless and defend the other Party hereto, including the other Party's parent, subsidiaries, and affiliates, and their respective officers, directors, agents, and employees, from and against all claims, demands, costs and expenses (including reasonable attorneys' fees) made or incurred by third parties in any manner, directly or indirectly, connected with or arising from any loss, damage or injury (including death) to any person(s) or property occurring on its side of the Interconnection Point to the extent that any such claim, demand, cost, or expense is attributable to any negligent or willful act or omission of the Indemnifying Party or its respective officers, directors, agents, or employees. In event such damage or injury is caused by the joint or concurrent negligence of the Parties hereto, the loss shall be borne by both Parties proportionately to their degree of negligence. No claim shall be made by either Party under this Section until the claims of third parties exceed $50,000 in any calendar year.

10.2 Limitation of Liability. Neither Party shall be liable to the other, whether in contract, in tort (including negligence and strict liability), under any warranty or otherwise, for damages for loss of profits or revenue, loss of use of any property, cost of capital, or other similar incidental or consequential damages; provided, however, that in the event any provisions of this Article are held to be invalid or unenforceable against MPS under the laws of the State of Missouri, this Article shall, to the extent of such invalidity or unenforceability, be void and of no effect, and no claim arising out of such invalidity or lack of enforceability shall be made against MPS or its officers, agents, or employees. Notwithstanding the foregoing, this Section 10.2 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 10.1 above.

ARTICLE 11 - FORCE MAJEURE

11.1 Force Majeure Defined. Force Majeure shall mean causes or events beyond the reasonable control of, and without the fault or negligence of, the Party claiming such Force

Majeure, including, without limitation, acts of God; unusually severe actions of the elements such as floods, earthquakes, storms, lightning, hurricanes, or tornadoes; sabotage; terrorism; war, riots or public disorders; fires; explosions; accidents in transportation affecting equipment or supplies; labor disputes; and actions or failures to act of any governmental agency (including expropriation, requisition, or changes in applicable law after January 25, 1999 including a change in any governmental approval or permit, or the conditions attached to such approval or permit and any other environmental constraint lawfully imposed by any governmental agency) preventing, delaying, or otherwise adversely affecting performance of a Party hereto or the cost of producing electricity where such consequences result despite the efforts of the affected Party to avoid or mitigate such consequences. Force Majeure shall not include the financial or monetary constraints or inability of either Party to pay its debts as they come due or the disallowance of recovery of any costs related to the sale and purchase of capacity or energy under this agreement by FERC, the MPSC or any other governmental agency. An event meeting the description of this section and affecting a contractor or supplier to a Party shall be a Force Majeure event for such Party.

11.2 Excuse by Reason of Force Majeure. Neither Project Company nor MPS shall be in default of any of its obligations under this Agreement, including but not limited to Project Company's obligation to deliver capacity and energy or MPS's obligation to receive capacity and energy, when such failure to perform is caused by a Force Majeure event. The affected Party shall be excused only for the period of time and to the extent necessary for the affected Party, using all reasonable efforts, to cure or mitigate the effects of the Force Majeure event provided, however, that this provision does not require the affected Party to settle a labor dispute. Notwithstanding the foregoing, a Force Majeure event shall not excuse the payment of any amounts due under this Agreement, including, without limitation, MPS's obligation to pay for capacity when it is excused from accepting or receiving or Project Company is excused from generating and delivering electricity; provided, however, that MPS shall be excused from making such payments after the earlier of (i) 120 days of a continuous Force Majeure event or (ii) the date on which Project Company is entitled to receive equivalent payments under its business interruption insurance. The Parties' respective obligations to perform shall resume on cessation of the Force Majeure event. Any period during which equipment failure has required reduced operation or shutdown of the Missouri Generator shall, for the purposes of the calculation provided in Section 5.3 hereinabove, be deemed to be a period of unavailability, unless the equipment failure results from a Force Majeure event.

11.3 Changes in Law. In the event that there is a change in law applicable to Project Company that is enacted or comes into effect after January 25, 1999 (and, in the latter case, where Project Company could not have known, using reasonable efforts, of the change in law on or before January 25, 1999) that increases (i) the operating costs (including the consumption of parasitic load) of the Missouri Generator or (ii) requires additional facilities and investment, in the case of (i) the Energy Charges set out in Section 5.2 shall be adjusted to keep Project Company whole against such increased operating costs and, in the case of (ii), the Capacity Charges set out in Section 5.1 shall be increased in the manner set out in Section 5.1(a) and (b) with respect to combustion turbine and interconnection costs, respectively, to compensate Project Company for the cost of the additional facilities.

11.4 Limitation on Force Majeure Delay. By written notice delivered to Project Company at least sixty (60) days prior to the date of intended termination, MPS may terminate this agreement pursuant to the provisions of Article 2 if one or more Force Majeure events delays the COD in combined cycle mode or causes a total Project outage following COD in combined cycle mode, in each case for more than twelve (12) months, unless the Force Majeure event (or events) affects a major piece of generating equipment, such as a rotor or stator, that must be custom-ordered and manufactured, in which case the applicable period will be eighteen (18) months.

ARTICLE 12 - CONSTRUCTION OF THE PROJECT

Starting sixty (60) days after the Effective Date, Project Company shall report to Purchaser, each Month, on the construction status and completion schedule for the Missouri Generator and related facilities. Such report shall, at a minimum, provide a schedule showing items completed and to be completed, the expected Commercial Operation Date, and, after construction commences, the estimated percent complete.

ARTICLE 13 - PERFORMANCE

13.1 Event of Default. (a) An Event of Default shall mean the failure of a Party to (i) make any payments in the time or manner required by Article 8 of this Agreement; or (ii) perform any other obligation stated herein in the time and manner required by this Agreement except where such failure to perform any such other obligation is the result of a Force Majeure event or is otherwise excused in accordance with this Agreement; or where an exclusive remedy is provided in this Agreement.

(b) The failure of Project Company to achieve COD for the Project in combined cycle mode by October 1, 2002, shall be an Event of Default.

(c) Either Party may declare an Event of Default if (i) the other Party (A) makes a general assignment for the benefit of creditors, (B) has a receiver, trustee, or similar such officer appointed for it and such appointment is not terminated within sixty (60) days, or (C) is subject to bankruptcy proceedings or suspension of payment; or (ii) proceedings are commenced for winding-up, liquidation, or dissolution of the other Party, and the situation giving rise to such proceedings is not remedied and such proceedings discontinued within sixty (60) days.

13.2 Notice of Default. Upon an Event of Default by a Party hereto, the other Party shall give written notice of such Event of Default to the Party in default. If the Event of Default is one described in clause (i) of Section 13.1(a), the Party in default shall have five (5) days after receipt of written notice to pay all amounts owed, plus interest determined pursuant to Section 17.5, and, if cured within such time, the Event of Default specified in such notice shall cease to exist. If the Event of Default is one described in clause (ii) of Section 13.1(a), the Party in default shall have thirty (30) days after receipt of written notice within which to cure such Default and, if cured within such time, the Event of Default specified in such notice shall cease to exist. If the Event of Default is the one described in Section 13.1(b), Project Company shall have ninety (90) days after receipt of written notice within which to cure such Default, and, if cured within such time, the Event of Default specified in such notice shall cease to exist.

13.3 Remedies for Default. If an Event of Default is not cured within the time period provided in Section 13.2, the Party not in default shall, in addition to any other rights and remedies provided by law, have a continuing right, until such Event of Default is cured, at its sole option, to suspend performance hereof, or to terminate this Agreement upon written notice to the Party in Default provided that to the extent that such Party seeking termination is prevented from so doing without first having FERC approval, acceptance by FERC of any required notice of termination or petition for withdrawal~~]~~; in all other respects, the rights and obligations of the Parties pursuant to this Agreement shall continue unaffected until the termination is effective. Any such termination shall not relieve MPS of its obligation to pay any unpaid invoices for any capacity made available or energy supplied prior to the date such termination is effective. The nondefaulting Party shall have the right to recover from the Party in Default all attorney's fees and court costs as may be reasonably incurred by reason of such Event of Default, but in all other respects the Parties have elected the remedies provided in this Agreement and waive all other remedies provided in law or in equity.

ARTICLE 14 - RIGHT OF INFORMATION

14.1 Right of Access. Project Company hereby grants to MPS, during the term of this Agreement, the right of ingress and egress at reasonable times to and from the Missouri Generator and site for purposes of inspecting any buildings or facilities constructed thereon. MPS shall give Project Company advance notice, which notice may be oral, before exercising its right of access established here.

14.2 Notice of Proceedings. Project Company will promptly notify MPS of any pending or anticipated federal or state regulatory, judicial or administrative actions, including but not limited to notice of violations involving the Missouri Generator or other facilities needed for its operation, which could affect Project Company's ability to carry out its obligation to supply capacity and energy hereunder or would be likely to result in an increase in the cost of capacity or energy as determined by the provisions of this Agreement.

ARTICLE 15 - PARTIES

15.1 Authority of Parties. Project Company represents and warrants to MPS that it is a limited liability company duly organized and validly existing under the laws of Delaware and that this Agreement and the purposes thereof are lawfully within the scope of its authority.

MPS represents and warrants to Project Company that it is a division of Utilicorp United, Inc. d/b/a Missouri Public Service, that Utilicorp United, Inc. is a corporation duly organized and validly existing under the laws of Delaware, and that this Agreement and the purposes thereof are lawfully within the scope of its authority.

Each Party further represents and warrants to the other that it holds, or will seek to obtain, all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

15.2 Survivorship of Obligations. The termination or cancellation of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability which shall occur or arise prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to whom such obligation is owed until the *expiration of the period of limitations imposed on such* obligation by the statute of limitations applicable to the obligation and/or such Party. The Parties also intend that the indemnification and limitation of liability provision contained in Section 10.1 hereof shall remain operative and in full force and effect regardless of any termination or cancellation of this Agreement, except with respect to actions or events occurring or arising after such termination or cancellation is effective.

15.3 Permitted Assignment. This Agreement shall be binding upon and inure to the benefit of the permitted successors and assigns of the Parties hereto. No permitted sale, assignment, transfer or other disposition shall release or discharge MPS or Project Company from its future obligations under this Agreement, but all such obligations shall be assumed by the successor or assign of the Party hereto.

Neither Party shall assign its interest in this Agreement in whole or part without the prior written consent of the other Party (except that Project Company may assign this agreement to an affiliate that is in the business of developing and operating power plants and may make an assignment for the benefit of lenders, in each case without the consent of MPS). Such consent shall not be unreasonably withheld. MPS will execute a consent to the assignment of this agreement by Project Company (or its permitted assignee) to and for the benefit of lenders in a form conventionally required for project financing, including without limitation provisions for payment to bank accounts controlled by lenders, for notices of default to lenders, and for lender cure rights and cure periods.

15.4 No Third Party Beneficiaries. This Agreement is not intended to and shall not, create rights, remedies or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assigned are solely for the use and benefit of the Parties, their successors in interest or assigns.

ARTICLE 16 - DISPUTE RESOLUTION

16.1 Administrative Committee Procedure. If any disagreement arises on matters concerning this Agreement, the disagreement shall be referred to representatives of each Party, who shall attempt to timely resolve the disagreement. If such representatives can resolve the disagreement, such resolution shall be reported in writing to and shall be binding upon the Parties. If such representatives cannot resolve the disagreement within a reasonable time, or a Party fails to appoint a representative within ten days of written notice of the existence of a disagreement, then either Party may initiate proceedings under Section 16.2 or 16.3, as appropriate.

16.2 Regulatory Matters. A dispute over a matter that is under the primary jurisdiction of the MPSC or the FERC may be submitted by either Party to such agency for resolution.

16.3 Arbitration. If pursuant to Section 16.1 the Parties are unable to resolve a disagreement arising on a matter pertaining to this Agreement but not subject to Section 16.2, such disagreement shall be settled by arbitration in Kansas City, Missouri. The arbitration shall be governed by the United States Arbitration Act (9 U.S.C. 1 *et seq.*), and any award issued pursuant to such arbitration may be enforced in any court of competent jurisdiction. This agreement to arbitrate and any other agreement or consent to arbitrate entered into in accordance herewith will be specifically enforceable under the prevailing arbitration law of any court having jurisdiction. Notice of demand for arbitration must be filed in writing with the other Party to this Agreement. Arbitration shall be conducted as follows:

(a) Either Party may give the other Party written notice in sufficient detail of the disagreement and the specific provision of this Agreement under which the disagreement arose. The demand for arbitration must be made within a reasonable time after the disagreement has arisen. In no event may the demand for arbitration be made if the institution of legal or equitable proceedings based on such disagreement is barred by the applicable statute of limitations. Any arbitration may be consolidated with any other arbitration proceedings relating to this Agreement.

(b) The Parties shall attempt to agree on a person with special knowledge and expertise with respect to the matter at issue to serve as arbitrator. If the Parties cannot agree on an arbitrator within ten days, each shall then appoint one person to serve as an arbitrator and the two thus appointed shall select a third arbitrator with such special knowledge and expertise to serve as Chairman of the panel of arbitrators; and such three arbitrators shall determine all matters by majority vote; provided however, if the two arbitrators appointed by the Parties are unable to agree upon the appointment of the third arbitrator with five days after their appointment, both shall give written notice of such failure to agree to the Parties, and, if the Parties fail to agree upon the selection of such third arbitrator within five days thereafter, then either of the Parties upon written notice to the other may require appointment from, and pursuant to the rules of, the Kansas City, Missouri office of the American Arbitration Association for commercial arbitration. Prior to appointment, each arbitrator shall agree to conduct such arbitration in accordance with the terms of this Agreement.

(c) The Parties shall have sixty days from the appointment of the arbitrator(s) to perform discovery and present evidence and argument to the arbitrator(s). During that period, the arbitrator(s) shall be available to receive and consider all such evidence as is relevant and, within reasonable limits due to the restricted time period, to hear as much argument as is feasible, giving a fair allocation of time to each Party to the arbitration. The arbitrator(s) shall use all reasonable means to expedite discovery and to sanction noncompliance with reasonable discovery requests or any discovery order. The arbitrator(s) shall not consider any evidence or argument not presented during such period and shall not extend such period except by the written consent of both Parties. At the conclusion of such period, the arbitrator(s) shall have forty-five calendar days to reach a determination. To the extent not in conflict with the procedures set forth herein, which shall govern, such arbitration shall be held in accordance with the prevailing rules of the Kansas City, Missouri office of the American Arbitration Association for commercial arbitration.

(d) The arbitrator(s) shall have the right only to interpret and apply the terms and conditions of this Agreement and to order any remedy allowed by this Agreement, but may not change any term or condition of this Agreement, deprive either Party of any right or remedy expressly provided hereunder, or provide any right or remedy that has been excluded hereunder.

(e) The arbitrator(s) shall give a written decision to the Parties stating their findings of fact, conclusions of law and order, and shall furnish to each Party a copy thereof signed by them within five calendar days from the date of their determination.

(f) Each Party shall pay the cost of the arbitrator(s) with respect to those issues as to which they do not prevail, as determined by the arbitrator or arbitrators.

16.4 Preliminary Injunctive Relief. Nothing in Section 16.3 shall preclude, or be construed to preclude, the resort by either Party to a court of competent jurisdiction solely for the purposes of securing a temporary or preliminary injunction to preserve the status quo or avoid irreparable harm pending arbitration pursuant to Section 16.3.

16.5 Settlement Discussions. The Parties agree that no written statements of position or offers of settlement made in the course of the dispute process described in this Article will be offered into evidence for any purpose in any litigation or arbitration between the Parties, nor will any such written statements or offers of settlement be used in any manner against either Party in any such litigation or arbitration. Further, no such written statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation or arbitration. At the request of either Party, any such written statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

ARTICLE 17 - MISCELLANEOUS

17.1 Governing Law. The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the applicable laws of the State of Missouri and of the United States of America.

17.2 Confidentiality. Neither Party shall disclose the terms of this Agreement to any third party (other than such Party's employees, counsel, accountants or other advisors; its affiliates and its lenders; and the employees, counsel, accountants, or other advisors of such affiliates and lenders) except in filings with the MPSC or the FERC or otherwise in order to comply with any applicable law, order, regulatory or exchange rule. Each Party shall notify the other Party of any proceeding of which it is aware that may result in disclosure and shall use reasonable efforts to prevent or limit such disclosure.

MPS agrees and covenants that to the extent permitted by law applicable to MPS, any and all information it receives pursuant to Article 14 will be kept confidential and shall not be disclosed by MPS to any third party without the express written consent of Project Company.

17.3 Section Headings Not to Affect Meaning. The descriptive headings of the various articles and sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof.

17.4 Computation of Time. In computing any period of time, prescribed or allowed by this Agreement, the designated period of time shall begin to run on the day immediately following the day of the act, event or default that precipitated the running of the designated period of time. The designated period shall expire on the last day of the period so computed unless that day is a Saturday, Sunday, or legal holiday recognized in the State of Missouri, in which event the period shall run until the end of the next Business Day.

17.5 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the then current average yield on Treasury Bills of the United States of America having a term of thirteen (13) weeks, as quoted in the Wall Street Journal as of the date on which the calculation begins, plus five hundred (500) basis points, but not to exceed the maximum rate which may be lawfully charged.

17.6 Entire Agreement. This Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter.

17.7 Counterparts. This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

17.8 Amendments. This Agreement may only be amended by written agreement signed by an authorized representative of each Party.

17.9 Severability. In the event the terms, covenants or conditions of this Agreement, or the application of any such terms, covenants or conditions shall be held invalid as to any Party or circumstance by any court or regulatory body having jurisdiction, all other terms, covenants and conditions of this Agreement and all other applications shall not be affected thereby and shall remain in full force and effect.

17.10 Waivers. Waivers of the provisions of this Agreement or any excuses of any violations of the Agreement shall be valid only if in writing and signed by an authorized officer of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

17.11 No Partnership Created. Notwithstanding any provision of this Agreement, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit, and if it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced to above, the Parties agree to negotiate promptly and in good faith with respect to such changes.

17.12 Character of Sale. The sale of unit power hereunder shall not constitute a sale, lease, transfer or conveyance to MPS or any other party of any ownership interests in any generating unit, nor does the sale of unit power hereunder constitute a dedication of ownership of any generating unit.

17.13 Notices. Any notice, demand, request, payment, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise provided) and shall be considered duly delivered when received by mail, facsimile, wire, or overnight courier, at the addresses listed below:

(i) To Project Company:

MEP Pleasant Hill, LLC
10750 East 350 Highway
Kansas City, MO 64138
Attention: Vice President - Asset Optimization

Payment by Wire:
For the Acct. of Project Company
The Northern Trust Company
ABA #
Account #

Invoices:

MEP Pleasant Hill, LLC
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138

Reason for Notice:	Attention:	Facsimile Number:
Statements/Payments	Accounting Dept.	(402) 498-4276
Contractual	Contract Administration	(402) 498-4543
Operations/Nominations	Scheduling Desk	(402) 498-4543

(ii) To MPS:

Missouri Public Service
10700 East 350 Highway
Kansas City, MO 64138
Attention: Vice President

Reason for Notice:	Attention:	Facsimile Number:
Statements/Payments	Accounting Dept.	(816) 936-8864
Contractual	Contract Administration	(816) 936-8639
Operations/Nominations	Scheduling Desk	(816) 936-8604

Each Party shall provide the other with all names telephone and facsimile numbers necessary for its performance under this Agreement; and either Party may change the information shown in Section 17.13 by giving written notice to the other Party.

17.14 Survival. Any provision(s) of this Agreement that expressly or by implication comes into or remains in force following the termination or expiration of this Agreement shall survive the termination or expiration of this Agreement.

For Missouri Public Service

[Name and Title]

Robert W. Holzwarth
VP & General Manager
UtiliCorp Power Services

Date: Feb 26, 1999

For MEP Pleasant Hill, LLC:

[Name and Title]

VT HCKGAN, President
MEP Pleasant Hill, LLC

Date: 26 Feb 99

Appendix A

Metering and Testing

A. ELECTRICITY METERING

(a) Location of Meters. The net electrical output for all of Project Company's electricity generators shall be measured by Project Company's electricity metering devices located at the electricity metering points ("Project Company Electricity Meters"). Unless otherwise mutually agreed by the Parties, the general location of the Project Company Electricity Meters shall be as shown on Figure A-1. The Project Company Electricity Meters shall be owned and operated in accordance with this Agreement, and shall be used for purposes of billing and payment in accordance with Article 8.

(b) Description of Meters. All Project Company Electricity Meters shall be designed in accordance with Prudent Industry Practices and shall consist of meters, metering current and voltage transformers and associated equipment required to determine the amounts and time of delivery of energy by Project Company to MPS. The Project Company Electricity Meters shall be sealed. Project Company may test its meters at its own expense at any time. MPS can request that such meters be tested upon reasonable cause to believe that the meters are inaccurate. MPS shall have witness rights to such tests. MPS will pay for such tests, unless the meters are found to be inaccurate outside the band guaranteed by the meter manufacturers, in which case Project Company will pay for the test.

(c) Meter Outputs/Data Recording/Telemetering. The Project Company Electricity Meters shall be capable of measuring MWs, MVARs and MWhs of each Project Company electric generator in accordance with appropriate NERC criteria and Prudent Industry Practices, and shall have the capability to totalize such data hourly. The output of the meters shall be recorded in electronic format and stored on-site. The necessary telemetering equipment and associated facilities, necessary to facilitate transmittal of the instantaneous MW and MVAR information to MPS, shall be owned and installed on-site by the Project Company.

B. FUEL METERING

(a) Location of Meters. The fuel delivered by MPS to the Project Company shall be measured by Project Company's fuel meters located at the Fuel Metering Points as shown in Figure B-1 ("Project Company Fuel Meters"). MPS shall deliver pipeline quality natural gas to the Fuel Meter Points in accordance with the terms of the Agreement and shall be used for purposes of billing and payment in accordance with Article 8 and Appendix C.

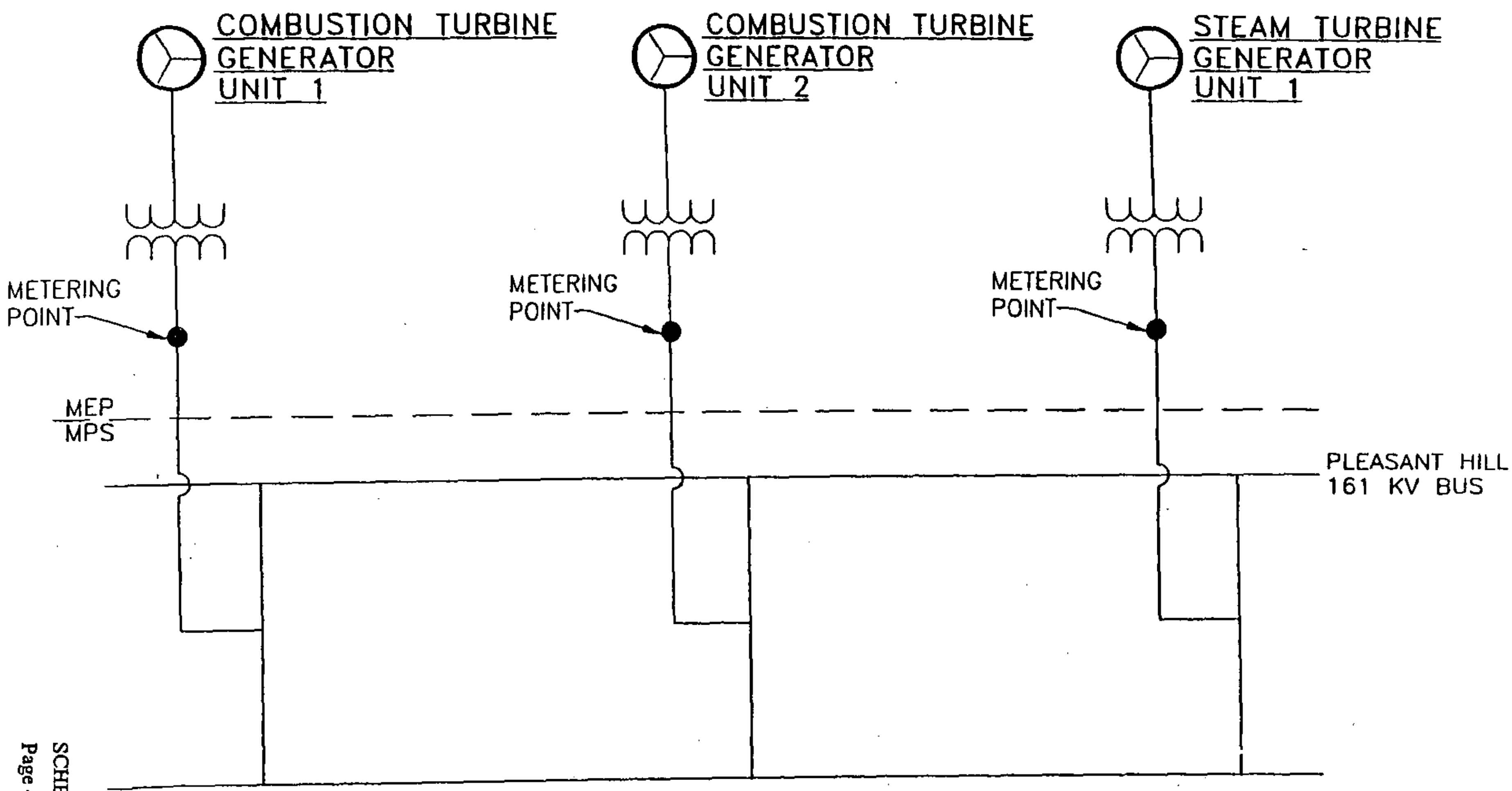
Fuel metering devices also shall be located at each Project Company combustion turbine and duct firing inlet at the approximate location shown on Figure A-2 to measure the fuel used by each combustion turbine to produce the net electrical output ("Unit Fuel Meters").

MPS can request, at its own expense, that Project Company Fuel Meters and Unit Fuel Meters can be tested upon reasonable cause to believe that the meters are inaccurate. MPS shall have witness rights to such tests.

(b) Description of Meters. All Project Company Fuel Meters shall be designed in accordance with Prudent Industry Practices and shall consist of meters and associated equipment required to determine the amounts and time of delivery of fuel by MPS to Project Company, and shall have the capability to totalize such data hourly. Project Company may test its meters at its own expense at any time. MPS can request that such meters be tested upon reasonable cause to believe that the meters are inaccurate. MPS shall have witness rights to such tests. MPS will pay for such tests, unless the meters are found to be inaccurate outside the band guaranteed by the meter manufacturers, in which case Project Company will pay for the test.

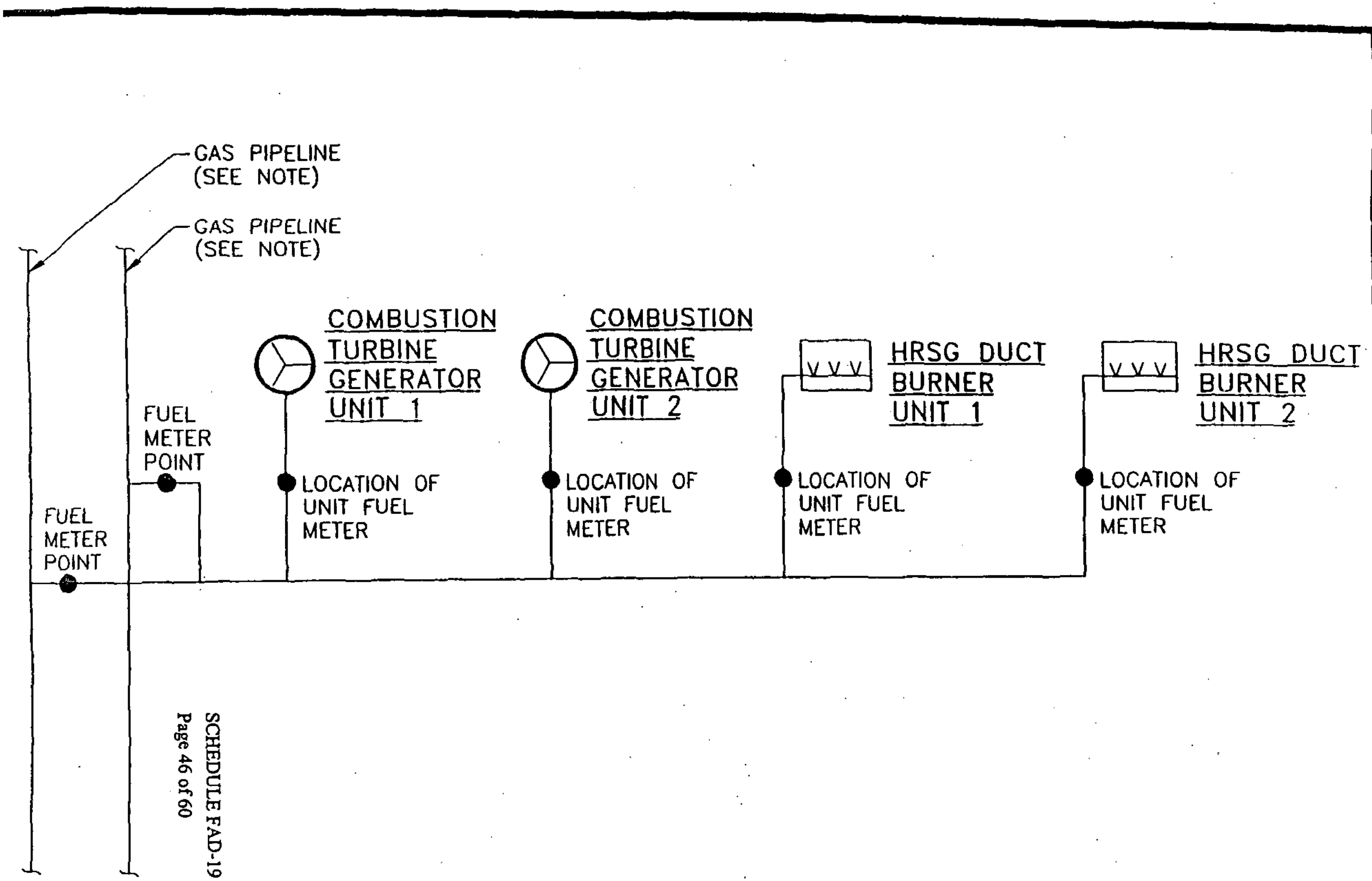
(c) Meter Outputs/Data Recording/Telemetering. The Project Company Fuel Meters shall measure fuel in units of MMBtu in accordance with Prudent Industry Practices and the tariffs of the interstate pipeline(s). The output of the meters shall be recorded in electronic format and stored on-site. The necessary telemetering equipment and associated facilities, necessary to facilitate transmittal of the real time fuel flow information from the Project Company Fuel Meters to MPS, shall be owned and installed by Project Company.

(d) Priority to MPS. To the extent that the Project Company has scheduled fuel delivery through the Project Company Fuel Meters from the interstate pipeline(s) in addition to that scheduled by MPS, MPS shall be given priority credit for delivery of fuel versus other Project Company gas schedulers.



MEP PLEASANT HILL, LLC

FIGURE A-1



NOTE:
ONE PIPELINE IS REQUIRED.
SECOND PIPELINE IS OPTIONAL

MEP PLEASANT HILL, LLC
FIGURE A-2

Appendix B

Interconnection Point; Criteria for Electrical Interconnection Agreement

A. Point of Interconnection

Project Company shall deliver net electrical output to MPS at the Interconnection Point for receipt by MPS in accordance with the terms of Appendix A. The interconnection voltage shall be at 161 kV. There will be three (3) generator step-up transformers at the Missouri Generator. MPS will provide a breaker position with a dead end tower for each of these step-up transformers, inside the MPS substation adjacent to the Missouri Generator. Project Company shall be responsible for termination of their conductor and associated dead end assemblies on the MPS dead end towers. MPS will connect the jumpers to the Project Company conductors at the dead end towers. The Point of Interconnection shall therefore be the connection of the Project Company and MPS conductors at the dead end towers.

B. Electrical Interconnection Agreement

This Appendix B, Section B defines the criteria for the Electrical Interconnection Agreement in accordance with the provisions of this Agreement.

1. No charges to Project Company for delivering power and energy from the Missouri Generator interconnection to MPS shall apply under the Electrical Interconnection Agreement.

2. Unless otherwise mutually agreed, the Electrical Interconnection Agreement shall require MPS to complete any required facilities upgrades, using due diligence and in accordance with Section 3.2, by December 31, 2000 subject to Force Majeure in accordance with this Agreement.

3. Unless otherwise mutually agreed, the Electrical Interconnection Agreement shall require MPS to complete the required MPS interconnection facilities, using due diligence and in accordance with Section 3.2, by September 30, 2000 subject to Force Majeure in accordance with this Agreement.

4. The transmission system upgrades identified by MPS shall be adequate (using the same standard for upgrades that the relevant utility would apply to any comparable generation unit interconnected to its system) to receive the entire output of the Missouri Generator delivery into MPS, not to exceed 603 MW.

5. The Electrical Interconnection Agreement shall have no obligation for Project Company to provide reactive power or other ancillary services to MPS without agreement by Project Company with MPS on acceptable compensation.

6. Project Company and MPS shall each have the right to metering data at the Points of Interconnection.

7. The term of the Electrical Interconnection Agreement shall be at least thirty (30) years.

8. Emergency conditions as used in the Electrical Interconnection Agreement shall be defined in accordance with Prudent Industry Practice in a manner not inconsistent with FERC's open access transmission policy.

9. MPS shall have the right to witness all metering testing by Project Company. Project Company shall have the right to witness all metering testing by MPS for the Points of Interconnection.

10. Project Company will agree not to interconnect the Missouri Generator with other transmission providers during the term of the Electrical Interconnection Agreement, and that MPS will be the sole transmission facility interconnected to the Missouri Generator, subject to the sale of MPS's Pleasant Hill substation.

11. Project Company will agree to pay to MPS the costs, if any, as determined by MPS, or a mutually agreed upon independent expert if requested by either party,

associated with MPS providing incremental transfer capability through its system above the Contract Capacity. MPS will identify such costs to Project Company within thirty (30) days after execution of this Agreement.

Appendix C

Effective Heat Rates

<u>MPS Gas Supply Requirement / Initial Guaranteed Maximum Effective Heat Rate</u>

Each hour that MPS schedules energy from the Missouri Generator, MPS is obligated to provide and pay for the natural gas for operations. The amount of gas in Btu to be supplied for each hour of energy scheduled by MPS (such amount of gas excluding that which MPS must provide for start-up and ramping requirements of the gas turbines) is calculated as the number of net kilo-watts of energy scheduled during that hour multiplied by the effective heat rate (measured in Btu/kWhr)(HHV) for the scheduled energy load and measured ambient temperature. Figures C-1 and C-2 present the initial guaranteed maximum effective heat rates that will be applied to any scheduled energy load, adjusted for temperature.

<u>Measured Ambient Temperature</u>

The ambient dry bulb temperature will be measured at the Missouri Generator site for each hour that MPS schedules energy. The temperature measured at 30 minutes into each hour will be the temperature used for locating the effective heat rate appearing in Figures C-1 and C-2. Project Company will be responsible for maintaining the temperature measurement device. The necessary telemetering equipment will be purchased and installed by the Project Company such that MPS and the Project Company will receive real time temperatures.

<u>COD Testing</u>

During testing to achieve COD, the heat rate of the Missouri Generator will be measured under the ambient conditions existing at that time. Heat rate tests will be conducted in accordance with testing procedures to be established in the EPC contract. Adjustments to the heat rate measured during COD testing, for the varying loads and temperatures, will be made according to manufacturers' recommendations to demonstrate compliance with performance guarantees required in the EPC contract. The adjusted calculated numbers will be further increased by 1.0% to account for expected degradation to the new and clean equipment plus an amount equal to the test measurement uncertainty (presently estimated as 0.5% for power and 1.8% for heat rate). These adjusted calculated heat rates for varying loads and temperatures will replace the initial guaranteed maximum effective heat rates appearing in Figures C-1 and C-2 to the extent that the tested/adjusted heat rates are less than the initial guarantees.

Notwithstanding the foregoing, the effective heat rates appearing in this Appendix C, as adjusted from time to time, will not be greater than the initial guaranteed maximum effective heat rates.

Annual Testing

The Project Company will conduct heat rate tests annually in a manner consistent with COD Testing, with the exception that only Missouri Generator instruments will be used. The measurements taken will be adjusted in a manner consistent with adjustments made during COD Testing. The new calculated effective heat rates will replace all heat rates then appearing in Figures C-1 and C-2, with the exception that the initial guaranteed heat rates will not be exceeded.

Notwithstanding the foregoing, the effective heat rates appearing in this Appendix C, as adjusted from time to time, will not be greater than the initial guaranteed maximum effective heat rates.

Adjustment to Load Range

Additional rows for lower loads will be added to Figures C-1 and C-2 to the extent that the Missouri Generator is able to operate at such lower loads and maintain compliance with all Missouri Generator permits and manufacturers recommended ranges of operation.

Fuel Quality

Fuel provided by MPS must be within the specifications identified in Figure C-3 in order for the effective heat rates contemplated within this Appendix C to be applicable. If fuel is provided that does not comply with the specifications in C-3, MEP reserves the right curtail operations of the Missouri Generator consistent with Section 4.1.

Figure C-1

Initial Guaranteed Maximum Effective Net Heat Rate (Btu(HHV)/kWhr)

Simple Cycle

Load Profile (MWs)	Btu/kWhr
320	10,850
301-319	10,950
281-300	11,200
261-280	11,400
260	11,500
161-170	10,650
151-160	10,950
141-150	11,200
131-140	11,400
130	11,500
115	12,200

Figure C-2

Initial Guaranteed Maximum Effective Heat Rate (Btu/kWhr)

Combined Cycle

	Temperature Range (Degrees Fahrenheit)		
Load Profile (MWs)	37.0 degrees and less	37.1 to 75.0 degrees	75.1 degrees and higher
500	7,250	7,150	7,300
476-499	7,260	7,170	7,250
451-475	7,280	7,250	7,270
425-450	7,380	7,350	7,350
400-424	7,430	7,430	7,430
251-275	7,300	7,180	NA
226-250	7,380	7,300	7,380
201-225	7,500	7,400	7,500
176-200	7,750	7,650	7,900
156-175	______	7,850	8,100

Figure C-3

Purchaser's Fuel Gas Constituents Range

CONSTITUENTS	RANGES
C6+	0-0.06
Propane C3H8	0-1.5
I-Butane C4H10	0-0.8
N-Butane C4H10	0-0.8
I-Pentane C5H12	0-0.8
N-Pentane CH12	0-0.8
Nitrogen N2	0-7.7
Methane CH4	84-98
Carbon Dioxide CO2	0-2.0
Ethane C2H6	0-6.0

Appendix D

Operating Limits

Minimum Generation Levels:

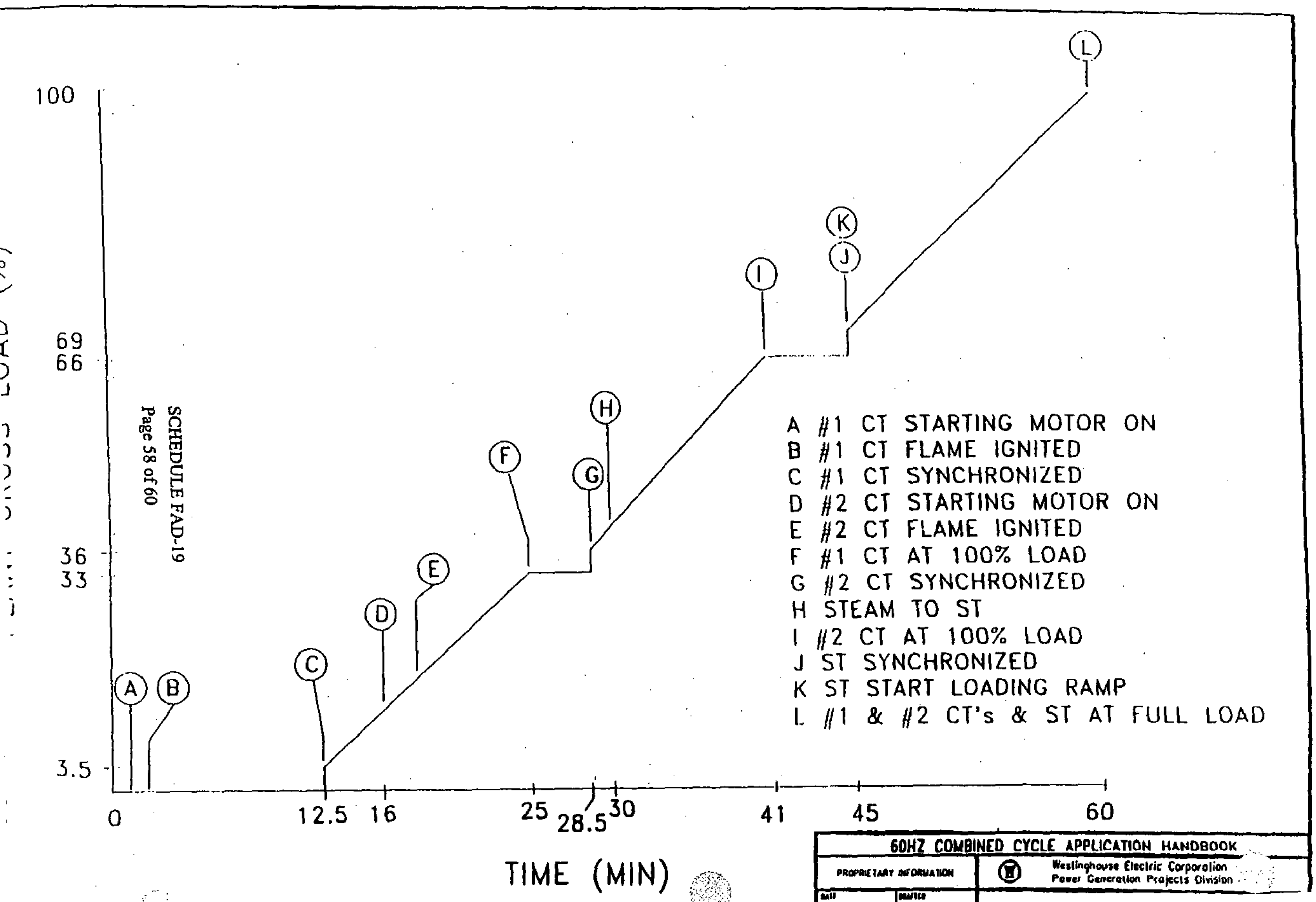
Project Company estimates that the Missouri Generator will be able to operate at minimum generation levels of, (1) 115 MW at 99°F and 117 MW at 54°F, per combustion turbine during the simple cycle phase; and (2) 156 MW at 99°F, 160 MW at 54°F, and 177 MW at 2°F for one combustion turbine during the combined cycle phase; and (3) 319 MW at 99°F, 327 MW at 54°F, and 361 MW at 2°F for both combustion turbines during the combined cycle phase. These estimates are based on preliminary performance data the Project Company has received from its intended EPC contractor coupled with the estimated minimum load level that the plant will be able to operate at under its air permit. The final minimum generation levels will be determined upon COD and will be based on manufacturers' recommendations and warranty operating conditions, as well as testing associated with achieving COD. At no time will be Missouri Generator operate, nor will MPS be able to schedule energy, at a generation level that would force the plant to operate in contradiction of any of its permits.

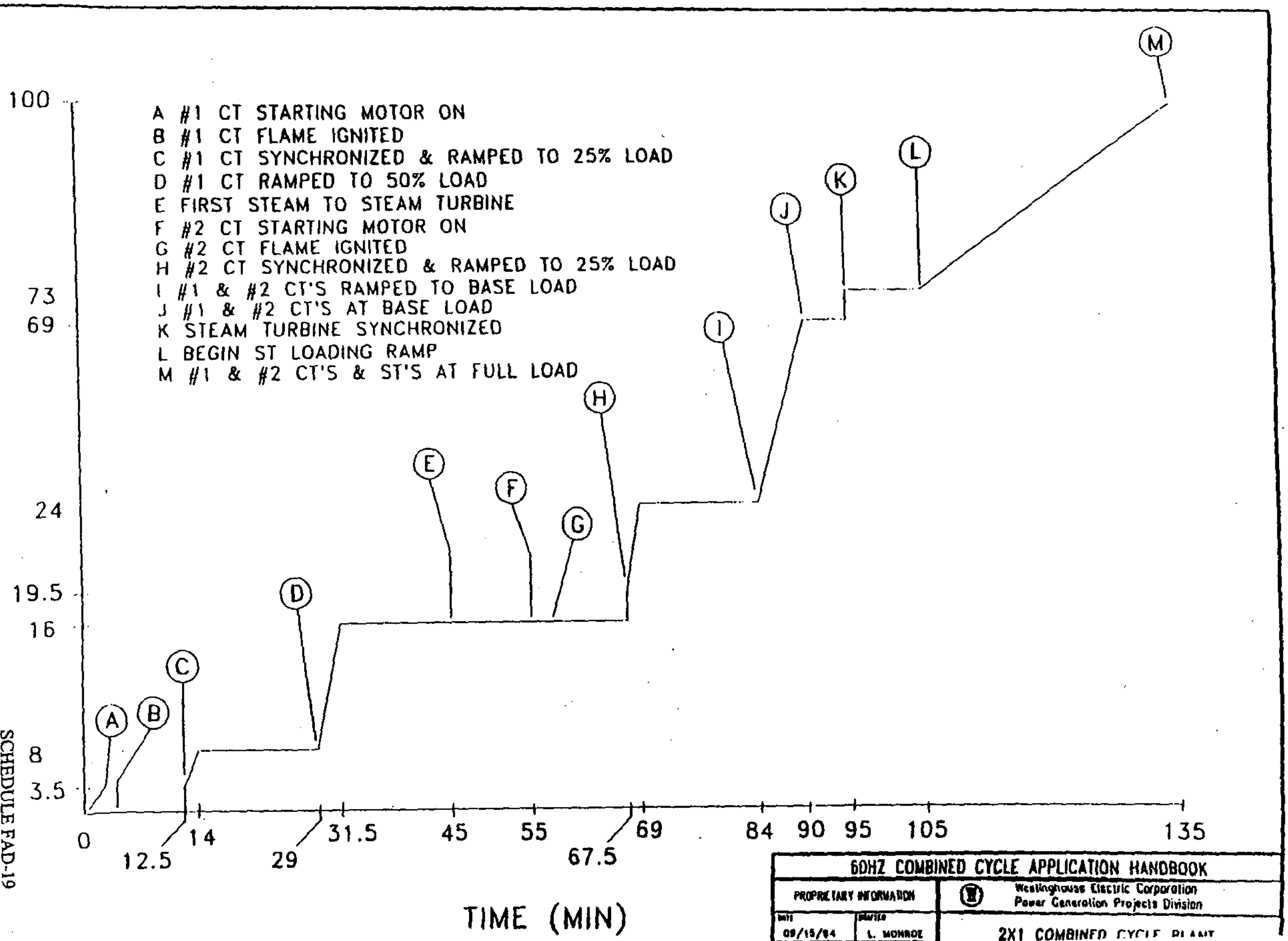
Ramp Rates:

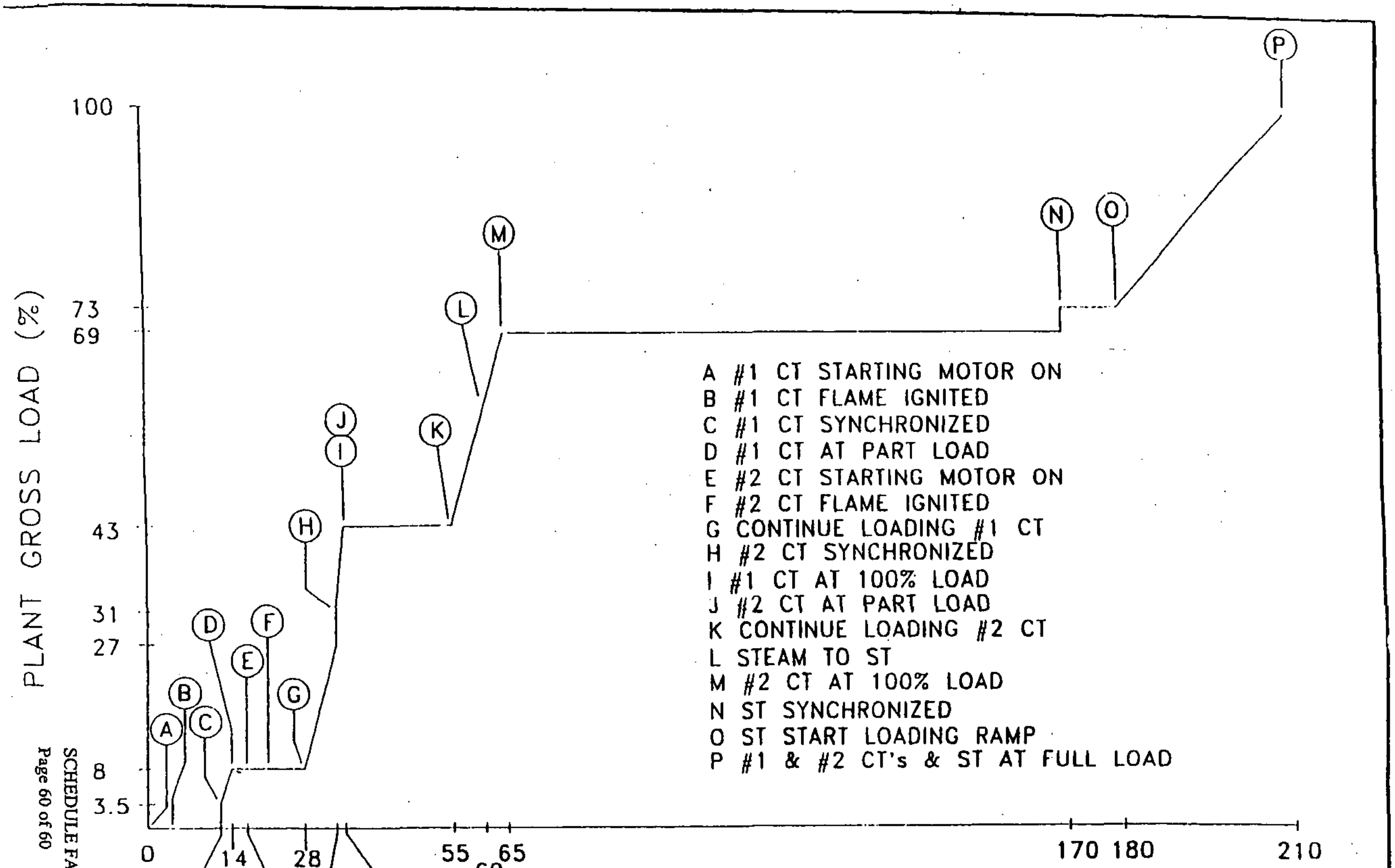
Ramp rates shall be in accordance with manufacturers' recommendations. Project Company's present understanding of those recommendations are provided in the attached figures.

Special Provision:

When Project Company is serving MPS from sources other than the Missouri Generator from time to time, procedures will need to be established to cover the generating unit ramp rates from synchronization to minimum load, and between minimum and full load. This may mean that changes in scheduled hourly deliveries requested by MPS may need to be accommodated over more time than the ten minute ramp across the top of the hour which is normal practice in the SPP. In such event MPS and Project Company will develop procedures, working with transmission providers, to allow longer ramp times if required to facilitate desired schedule changes.


100
69
66
36
33
3.5
0
12.5
16
25
28.5
30
41
45
60
TIME (MIN)
A #1 CT STARTING MOTOR ON
B #1 CT FLAME IGNITED
C #1 CT SYNCHRONIZED
D #2 CT STARTING MOTOR ON
E #2 CT FLAME IGNITED
F #1 CT AT 100% LOAD
G #2 CT SYNCHRONIZED
H STEAM TO ST
I #2 CT AT 100% LOAD
J ST SYNCHRONIZED
K ST START LOADING RAMP
L #1 & #2 CT's & ST AT FULL LOAD
60HZ COMBINED CYCLE APPLICATION HANDBOOK
PROPRIETARY INFORMATION
Westinghouse Electric Corporation
Power Generation Projects Division


A #1 CT STARTING MOTOR ON
B #1 CT FLAME IGNITED
C #1 CT SYNCHRONIZED & RAMPED TO 25% LOAD
D #1 CT RAMPED TO 50% LOAD
E FIRST STEAM TO STEAM TURBINE
F #2 CT STARTING MOTOR ON
G #2 CT FLAME IGNITED
H #2 CT SYNCHRONIZED & RAMPED TO 25% LOAD
I #1 & #2 CT'S RAMPED TO BASE LOAD
J #1 & #2 CT'S AT BASE LOAD
K STEAM TURBINE SYNCHRONIZED
L BEGIN ST LOADING RAMP
M #1 & #2 CT'S & ST'S AT FULL LOAD
100
73
69
24
19.5
16
8
3.5
0
12.5
14
29
31.5
45
55
67.5
69
84
90
95
105
135
TIME (MIN)
60HZ COMBINED CYCLE APPLICATION HANDBOOK
PROPRIETARY INFORMATION
Westinghouse Electric Corporation
Power Generation Projects Division
09/15/94
L. MONROE
2X1 COMBINED CYCLE PLANT



60HZ COMBINED CYCLE APPLICATION HANDBOOK

PROPRIETARY INFORMATION

Westinghouse Electric Corporation
Power Generation Projects Division

DATE 09/15/94 DRAFTER L. MONROE

2X1 COMBINED CYCLE ...

UTILICORP UNITED

MPS Power Supply

Progress Report

January 11, 1999

Presented by UPS

MPS

POWER SUPPLY

PROGRESS REPORT

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Overview

This report summarizes the results of the MPS supply side resource acquisition process begun in May, 1998.

MPS will face a significant capacity shortfall beginning June, 2000 when two of its major purchase power contracts totaling 280 MW expire. The capacity shortfall will become more acute on June 1, 2001 when the remaining contract totaling 115 MW expires.

On May 22, 1998, UPS issued a RFP for capacity and energy to meet the MPS capacity and energy needs for the period June, 2000 to May, 2004. On July 3, 1998, eight proposals were received in response to the RFP.

Analysis of the proposals was conducted in the 3rd and 4th quarters of 1998. The analysis process was complicated by the energy price volatility and equipment shortages resulting from the sharp increase in the spot market price of energy in June and July. Proposals were revised and/or withdraw and one bidder was purchased and assigned its proposal to another bidder. In addition, Empire District issued a RFP for purchase/ownership in a proposed combined cycle unit to be constructed near Joplin, MO. The most recent revised proposal was received on January 6, 1999.

Nonetheless, the evaluation process has led to a conclusion and recommendation which will allow MPS to secure the major portion of its 2000-2006 capacity needs at an attractive price. The recommended June, 2000 to May, 2006 supply side resource plan is as follows:

June, 2000 to May, 2001	Purchase 135 MW from Aquila for the months of June - Sept, 2000. Purchase 120 MW from WestPlains Kansas for the months of June, 2000 to May, 2001.
June, 2001 to May, 2006	Enter into a PPA with Houston Industries which will provide 500 MW during the months of June to Sept and 200 MW in the remaining months.
June 2003 to May, 2006	Purchase incremental capacity needs through 12 month contracts.
June, 2005	Purchase/construct additional intermediate term resource of 150 MW.

The remainder of this document provides the results of the analysis and supporting material.

Significant Milestones

May 22, 1998	Issued Request for Proposal for Supply Resources for June 1, 2000 to May 31, 2004.
July 3, 1998	Received eight proposals: Aquila Power — Basin Electric Cooperative Carolina Power & Light — LS Power, LLC New Century Energies — NorAm Energy Services, Inc. NP Energy Inc. — Southern Company
August 21, 1998	Initial evaluation of proposals completed by Burns & McDonnell. Results indicated that a self build EWG option supplemented with short term purchases for 2000/2001 offered the lowest cost option.
August 25, 1998	Requested that original bidders confirm their interest and update their proposals. All bidders with the exception of LS Power responded in the affirmative and either confirmed their original pricing or offered revised pricing. With the exception of New Century Energies, Aquila and Basin, all bidders stated that they were no longer able to meet a June 1, 2000 delivery date.
September 9, 1998	Executed letter of intent to purchase excess capacity from Sunflower Electric Cooperative.
September, 1998	Determined that only three cost effective supply options existed for the June, 2000 to May, 2001 period: Aquila, New Century Energies and Sunflower. The Basin proposal was not cost effective due to the high capacity charge.
October 1, 1998	Empire issued RFP for the purchase of capacity and energy from proposed 500 MW combined cycle plant near Joplin, MO.
November 3, 1998	Completed evaluation of the three cost effective supply resources available for the June, 2000 to May, 2001 period. Portfolio consisting of a mix of Sunflower and Aquila resources determined to be most cost effective.
November 5, 1998	Submitted proposal to take a 50% equity interest in Empire 500 MW combined cycle project.
November 6, 1998	Requested that bidders again confirm their interest and update their proposals. Established November 30, 1998 as due date for best and final offers. All bidders except Basin Electric, LS Power and Southern verbally indicated a continued interest. Carolina Power & Light and NP Energy subsequently withdrew their proposals.

Significant Milestones

November, 1998	Carolina Power & Light decided that it could not commit resources without a long term agreement and withdrew from the bidding process. NP Energy decided that it could not commit resources due to its financial position and withdrew its proposal in favor of Houston Industries.
November 9, 1998	Received contract from Aquila Power for 135 MW of peaking capacity for period June 1, 2000 to September 30, 2000.
November 30, 1998	Received revised proposals from Aquila Power and Houston Industries for the June, 2001 to May, 2006 period.
December 17,1998	Executed contract to purchase excess capacity from Sunflower.
December 21, 1998	Contacted Houston Industries and advised them that their proposal was not cost effective as structured and requested that they consider revising their proposal.
December 29, 1998	Met with Houston Industries to discuss MPS' capacity needs and provide information which would allow them to improve their proposal.
January 4, 1998	Met with Aquila to begin the process of clarifying and solidifying the terms and conditions of their proposal.
January 6, 1999	Met with Houston Industries and received their revised proposal.
January 7, 1999	Completed evaluation of Houston Industries proposal.
January 11, 1999	Meeting with DOUG Group to discuss status of MPS power supply.

Aquila Original Proposal
July 6, 1998

Option 1

Capacity:	100 MW from June, 2000 thru Sept, 2000 75 MW from Oct, 2000 thru May, 2001
Resource:	Aquila purchase from LS Power Batesville Project
Capacity Price:	$10,000/MW-mo. from June, 2000 thru Sept, 2000 $750/MW-mo. from Oct, 2000 thru May, 2001
Energy Price:	$100/MWh plus transmission losses
Transmission:	~$2,162/MW-mo. plus ~$0.41/MWh losses

Option 2

Capacity:	75 MW from June, 2000 thru May, 2001
Capacity Price:	$3,833.33/MW-mo. from June, 2000 thru May, 2001
Energy Price:	$100/MWh plus transmission losses
Transmission:	~$2,162/MW-mo. plus ~$0.41/MWh losses

Option 3

Capacity:	100 MW from June, 2001 thru May, 2004
Capacity Price:	$4,000/MW-mo. from June, 2001 thru May, 2002 $4,500/MW-mo. from June, 2002 thru May, 2003 $5,000/MW-mo. from June, 2003 thru May, 2004
Energy Price:	$100/MWh plus transmission losses
Transmission:	~$2,162/MW-mo. plus ~$0.41/MWh losses
Buyout Cost	$10,000/MW on June 1, 2002 $20,000/MW on June 1, 2003
Status:	Original proposal has be superseded by peaking purchase for 2000/2001 and revised proposal dated November 30, 1998.

Aquila Purchase Contract
for
June 1, 2000 to Sept. 30, 2000

Basis:	Option 1 of Aquila July 6, 1998 Proposal
Resource:	Aquila purchase from LS Power Batesville Project
Capacity:	100 MW minimum, 135 MW maximum.
Capacity Price:	$6,850/MW-mo. from June, 2000 thru Sept, 2000
Energy Price:	$100/MWh plus transmission losses
Transmission:	~$2,162/MW-mo. plus ~$0.41/MWh losses
Status:	Contract awaiting signatures.

Aquila Revised Proposal
November 30, 1998

Term:	June, 2001 thru May, 2004 with option to extend contract for one year.
Capacity:	320 MW from June, 2001 thru Sept, 2001 200 MW from Jan, 2001 thru May, 2005 300 MW from April thru Sept of each year from 2002 to 2005
Resource:	Aquila purchase from LS Power Batesville project and proposed new 500 MW combined cycle plant at Pleasant Hill, MO.
Capacity Price:	$6,200/MW-mo. for 320 MW from June, 2001 thru Sept, 2001 $6,400/MW-mo. for 200 MW from Jan, 2002 thru May, 2005 $7,500/MW-mo. for 200 MW from June, 2005 thru May, 2006 $8,000/MW-mo. for 300 MW from April thru Sept of each year from April, 2002 thru May, 2005. $9,000/MW-mo. for 300 MW from June thru Sept, 2005 and April thru May, 2006.
Tolling Fee:	$1.25/MWh (1998 $) escalated at CPI
Fuel Supply:	MPS will be responsible for securing, transporting all natural gas required to generate the energy supplied to MPS.
Transmission:	Not Applicable as capacity and energy will be delivered to the MPS system.
Status:	Proposal currently under evaluation.

Basin Electric Proposal
July 2, 1998

Capacity:	100 MW from June, 2000 thru May, 2004
Resource:	Basin Electric generation resources
Capacity Price:	\$12,600/MW-mo. from June, 2000 thru May, 2001 \$13,100/MW-mo. from June, 2001 thru May, 2002 \$13,600/MW-mo. from June, 2002 thru May, 2003 \$14,100/MW-mo. from June, 2003 thru May, 2004
Energy Price:	\$12.70/MWh from June, 2000 thru May, 2001 \$13.10/MWh from June, 2001 thru May, 2002 \$13.50/MWh from June, 2002 thru May, 2003 \$13.90/MWh from June, 2003 thru May, 2004
Transmission:	\$2,530/MW-mo. from June, 2000 thru May, 2004
Status:	Proposal is assumed to have expired. Basin did not respond to UCU letter of November 6, 1998 in which Basin was requested to reconfirm its interest in supplying capacity and energy to MPS.

Carolina Power & Light Proposal

July 2, 1998 Proposal

Capacity:	150 MW from June, 2000 thru May, 2004
Resource:	150 MW peaking resource to be constructed on MPS system
Capacity Price:	\$4,690/MW-mo. from June, 2000 thru May, 2001 \$4,810/MW-mo. from June, 2001 thru May, 2002 \$4,930/MW-mo. from June, 2002 thru May, 2003 \$5,050/MW-mo. from June, 2003 thru May, 2004
Energy Price:	Energy price to be the sum of the variable O&M cost and 12X the index gas price in \$/MMBtu.
Transmission:	Not applicable as capacity and energy will be delivered to the MPS system.
Status:	Proposal superseded by September 4, 1998 Proposal.

Sept. 4, 1998 Revised Proposal

Capacity:	150 MW from June, 2001 thru May, 2005
Resource:	150 MW peaking resource to be constructed on MPS system
Capacity Price:	\$5,394/MW-mo. from June, 2000 thru May, 2001 \$5,532/MW-mo. from June, 2001 thru May, 2002 \$5,670/MW-mo. from June, 2002 thru May, 2003 \$5,808/MW-mo. from June, 2003 thru May, 2004
Energy Price:	Energy price to be the sum of the variable O&M cost and 12X the index gas price in \$/MMBtu.
Transmission:	Not Applicable as capacity and energy will be delivered to the MPS system.
Status:	Proposal is assumed to have expired. CP&L elected to not respond to UCU letter of November 6, 1998 in which CP&L was requested to reconfirm its interest in supplying capacity and energy to MPS.

LS Power Proposal
July 2, 1998

Capacity:	540 MW from June, 2001 thru May, 2011
Resource:	2 x 270 MW combined cycle unit to be constructed on MPS system
Capacity Price:	\$5,500/MW-mo. escalated at 2% per year
Energy Price:	Sum of \$1.00/MWh (1998 \$) escalated at GDP and the product of guaranteed unit heat rate (7,500 Btu/kwh @ full load) and the gas price in \$/MMBtu.
Fuel Supply:	MPS responsible for securing, transporting all natural gas required to generate the energy supplied to MPS.
Transmission:	Not Applicable as facility would be constructed on the MPS system.
Status:	Proposal withdrawn due to increase in equipment cost and unwillingness to accept a shorter term contract.

New Century Energies

July 3, 1998 Proposal

Capacity:	100 MW from June, 2000 thru May, 2004		
Resource:	System resources of Southwestern Public Service		
Capacity Price:	\$4,650/MW-mo. from June, 2000 thru May, 2001 \$5,200/MW-mo. from June, 2001 thru May, 2002 \$5,400/MW-mo. from June, 2002 thru May, 2003 \$5,400/MW-mo. from June, 2003 thru May, 2004		
Energy Price:	Projected energy price:	2000	\$20.00/MWh
		2001	19.17
		2002	18.79
		2003	16.90
		2004	17.38
Transmission:	~\$3,861/MW-mo. plus losses		
Status:	Proposal remains valid.		

Houston Industries

July 2, 1998 Proposal

Capacity:	100 MW from June, 2001 thru May, 2004
Resource:	Cogeneration plant in SE Illinois near St. Louis.
Capacity Price:	\$8,500/MW-mo. from June, 2001 thru May, 2002 \$8,750/MW-mo. from June, 2002 thru May, 2003 \$9,000/MW-mo. from June, 2003 thru May, 2004
Energy Price:	Projected energy price: 2001 \$22.00/MWh 2002 22.50 2003 23.00
Transmission:	~\$1,100/MW-mo. plus losses
Status:	Proposal superseded by December 1, 1998 proposal.

December 1, 1998 Proposal

Capacity:	300 MW from June, 2001 thru May, 2006
Resource:	New peaking facility on MPS system
Capacity Price:	\$4,500/MW-mo. (2001 \$) escalated at 2.5% per year
Energy Price:	Sum of \$1.00/MWh (2001 \$) escalated at GDP and the product of guaranteed unit heat rate (10,600 Btu/kwh @ full load) and the gas price in \$/MMBtu.
Fuel Supply:	MPS responsible for securing, transporting all natural gas required to generate the energy supplied to MPS.
Transmission:	Not applicable since facility would be constructed on the MPS system.
Status:	Proposal replaced with January 6, 1999 proposal.

Houston Industries

January 6, 1998 Proposal

Term:	June, 2001 thru May, 2006
Capacity:	300 MW from June thru Sept of each year; and, 200 MW from Jan thru May and Oct thru Dec of each year.
Resource:	New peaking facility on MPS system
Capacity Price:	$8,420/MW-mo. from June thru Sept of each year; and, $4,210/MW-mo. from Jan thru May and Oct thru Dec of each year.
Energy Price:	Sum of $0.75/MWh and the product of guaranteed unit heat rate (10,600 Btu/kwh) and the gas price in $/MMBtu.
Fuel Supply:	Houston Industries responsible for securing, transporting all natural gas required to generate the energy supplied to MPS.
Transmission:	Not applicable since facility would be constructed on the MPS system.
Status:	Proposal remains valid.

NP Energy Inc.

Capacity:	100 MW from June, 2001 thru May, 2004
Resource:	New peaking facility on Public Service Company of Oklahoma system
Capacity Price:	\$2,500/MW-mo.
Energy Price:	Spot market energy price at time of purchase.
Transmission:	~\$2,440/MW-mo. plus losses.
Status:	Proposal superseded by September 4, 1998 proposal.

September 4, 1998 Proposal

Capacity:	200-300 MW from June, 2001 thru May, 2006
Resource:	New peaking facility on MPS system.
Capacity Price:	\$4,000/MW-mo. escalated at 2.5% per year.
Energy Price:	Sum of \$1.00/MWh (2001 \$) escalated at 2% and the product of guaranteed unit heat rate (10,600 Btu/kwh @ full load) and the gas price in \$/MMBtu.
Fuel Supply:	MPS responsible for securing, transporting all natural gas required to generate the energy supplied to MPS.
Transmission:	Not applicable since facility would be constructed on the MPS system.
Status:	Proposal superseded Houston Industries proposal of December 1, 1998.

Southern Company Energy Marketing

Capacity:	100 MW from June, 2001 thru May, 2004
Resource:	New peaking facility on Entergy's system.
Capacity Price:	\$2,650/MW-mo. escalated at 3.25% per year.
Energy Price:	Sum of \$2.25/MWh and the product of guaranteed unit heat rate (8,350 Btu/kwh @ full load) and the Henry Hub gas price in \$/MMBtu.
Transmission:	~\$2,162/MW-mo. plus ~\$0.41/MWh losses.
Status:	Proposal is assumed to have expired. SCEM elected to not respond to UCU letter of November 6, 1998 in which SCEM was requested to reconfirm its interest in supplying capacity and energy to MPS.

Missouri Power Supply
Bid Comparison
6/1/2000 - 5/31/2001
Data in $x1,000

Portfolio>	A	B	C	D
Megawatt Capacity				
SEC	120	155	100	55
Aquila	135	100	155	100
SPS	0	0	0	100
UE	115	115	115	115
Total	370	370	370	370
Capacity Cost				
SEC	6,984	9,021	5,820	3,201
Aquila	4,866	3,605	5,587	3,605
SPS	-	-	-	8,671
UE	7,176	7,176	7,176	7,176
Total	19,026	19,802	18,583	22,653
Energy Cost				
	-	-	-	-
Total Cost				
	19,026	19,802	18,583	22,653

Missouri Power Supply
Bid Comparison
6/1/2000 - 5/31/2006
Data in $x1,000

Priniciple Power Resource		Annual Cost $x1,000						NPV	NPV
	From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-05	Jun-00	Jun-00
	To>	May-01	May-02	May-03	May-04	May-05	May-06	May-05	May-06
	Notes								
Aquila Power	1	104,034	128,577	136,625	144,396	153,656	172,209	525,730	634,251
Houston Industries	2	104,098	121,772	128,846	138,069	148,294	161,362	505,480	607,165
Empire SLCC as EWG	3, 4	104,080	128,256	136,907	148,963	159,975		533,379	N/A
Empire SLCC as Rate Base Asset	3, 5	104,080	131,740	140,038	153,657	164,310		545,252	N/A

1) Aquila proposal is for 4 years with option for 5th year, only 4 years shown.
2) Houston Industries proposal is for 5 years, only 4 years shown.
3) 250 MW ownership in SLCC with investment @ $440/kw ($110M).
4) AMEP does not have any interest in owning 50% interest in SLCC
5) UED does not want a long term rate base asset.

Missouri Power Supply
Resource Mix Comparison

	Capacity in MW					
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-05
To>	May-01	May-02	May-03	May-04	May-05	May-06
Empire Option						
Existing Generation	1,049	1,049	1,049	1,049	1,049	1,049
UE Purchase	115					
SEC Purchase	120	-				
Aquila Purchase	135					
SLCC Capacity		250	250	250	250	250
PkPPA 2001		150	150	150	150	150
PkPPA 2003				150	150	150
Short Term Pkng		35	90	-	60	125
Total	1,419	1,484	1,539	1,599	1,659	1,724
Aquila Option						
Existing Generation	1,049	1,049	1,049	1,049	1,049	1,049
UE Purchase	115					
SEC Purchase	120	115				
Aquila Purchase	135	320	500	500	500	500
PkPPA 2005					-	150
Short Term Pkng				50	110	25
Total	1,419	1,484	1,549	1,599	1,659	1,724
Houston Industries Peaking Option						
Existing Generation	1,049	1,049	1,049	1,049	1,049	1,049
UE Purchase	115					
SEC Purchase	120					
Aquila Purchase	135					
HI Purchase		500	500	500	500	500
PkPPA 2005					-	150
Short Term Pkng			-	50	110	25
Total	1,419	1,549	1,549	1,599	1,659	1,724

MPS POWER SUPPLY
Empire Proposal
1999 - 2007
Loads & Resources

	SYSTEM PEAK RESPONSIBILITY (MW)					SYSTEM CAPACITY (MW)							
YEAR	SYSTEM LOAD NET 1-HR	FIRM PURCHASE (-)	FIRM SALES (+)	TOTAL SYSTEM PEAK RESP.	TOT SYSTEM CAPACITY RESP. * (5)/(1-CM)	ACCREDITED GENERATING CAPACITY	BASE/INT PURCHASE	PEAKING PURCHASE (-)	COMMITTED PURCHASE (+)	Empire SLCC Investment	TOTAL SYSTEM CAPACITY	CAPACITY BALANCE (12-6)	CAPACITY MARGIN (%) (12-5)/(12)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1998	1,194	0	0	1,194	1,357	1,049	-	-	345	-	1,394	37	14.3%
1999	1,217	0	0	1,217	1,383	1,049	-	-	395	-	1,444	61	15.7%
2000	1,256	0	0	1,256	1,428	1,049	-	-	380	-	1,429	1	12.1%
2001	1,302	0	0	1,302	1,480	1,049	-	185	-	250	1,484	4	12.3%
2002	1,351	0	0	1,351	1,536	1,049	-	240	-	250	1,539	3	12.2%
2003	1,403	0	0	1,403	1,595	1,049	-	300	-	250	1,599	4	12.3%
2004	1,458	0	0	1,458	1,657	1,049	-	360	-	250	1,659	2	12.1%
2005	1,516	0	0	1,516	1,723	1,049	-	425	-	250	1,724	1	12.1%
2006	1,577	0	0	1,577	1,792	1,049	-		-	250	1,299	-493	-21.4%
2007	1,641	0	0	1,641	1,865	1,049	-		-	250	1,299	-566	-26.3%
2008	1,708	0	0	1,708	1,941	1,049	-		-	250	1,299	-642	-31.5%

Footnotes of forecasted data:

Minimum Capacity Margin (MCM) = 12.00%

Total System Capacity Resp. =

$$\frac{\text{Total System Peak Resp.}}{1 - \text{MCM} + .00005} + .499$$

0.1304

MPS POWER SUPPLY
Aquila Proposal
1999 - 2007
Loads & Resources

	SYSTEM PEAK RESPONSIBILITY (MW)					SYSTEM CAPACITY (MW)							
YEAR	SYSTEM LOAD NET 1-HR	FIRM PURCHASE (-)	FIRM SALES (+)	TOTAL SYSTEM PEAK RESP.	TOT SYSTEM CAPACITY RESP. * (5)/(1-CM)	ACCREDITED GENERATING CAPACITY	BASE/INT PURCHASE	PEAKING PURCHASE (-)	COMMITTED PURCHASE (+)	AQP Purchase	TOTAL SYSTEM CAPACITY	CAPACITY BALANCE (12-6)	CAPACITY MARGIN (%) (12-5)/(12)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1998	1,194	0	0	1,194	1,357	1,049	-	-	345	-	1,394	37	14.3%
1999	1,217	0	0	1,217	1,383	1,049	-	-	395	-	1,444	61	15.7%
2000	1,256	0	0	1,256	1,428	1,049	-	-	380	-	1,429	1	12.1%
2001	1,302	0	0	1,302	1,480	1,049	-	115	-	320	1,484	4	12.3%
2002	1,351	0	0	1,351	1,536	1,049	-	-	-	500	1,549	13	12.8%
2003	1,403	0	0	1,403	1,595	1,049	-	50	-	500	1,599	4	12.3%
2004	1,458	0	0	1,458	1,657	1,049	-	110	-	500	1,659	2	12.1%
2005	1,516	0	0	1,516	1,723	1,049	-	175	-	500	1,724	1	12.1%
2006	1,577	0	0	1,577	1,792	1,049	-		-		1,049	-743	-50.3%
2007	1,641	0	0	1,641	1,865	1,049	-		-		1,049	-816	-56.4%
2008	1,708	0	0	1,708	1,941	1,049	-		-		1,049	-892	-62.8%

Footnotes of forecasted data:

Minimum Capacity Margin (MCM) =	12.00%
Total System Capacity Resp. =	

$$\frac{\text{Total System Peak Resp.}}{1 - MCM + .00005} + .499$$

0.1304

MPS POWER SUPPLY
Houston Industries Proposal
1999 - 2007
Loads & Resources

	SYSTEM PEAK RESPONSIBILITY (MW)					SYSTEM CAPACITY (MW)							
YEAR	SYSTEM LOAD NET 1-HR	FIRM PURCHASE (-)	FIRM SALES (+)	TOTAL SYSTEM PEAK RESP.	TOT SYSTEM CAPACITY RESP. * (5)/(1-CM)	ACCREDITED GENERATING CAPACITY	BASE/INT PURCHASE	PEAKING PURCHASE (-)	COMMITTED PURCHASE (+)	Houston Industries Purchase	TOTAL SYSTEM CAPACITY	CAPACITY BALANCE (12-6)	CAPACITY MARGIN (%) (12-5)/(12)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1998	1,194	0	0	1,194	1,357	1,049	-	-	345	-	1,394	37	14.3%
1999	1,217	0	0	1,217	1,383	1,049	-	-	395	-	1,444	61	15.7%
2000	1,256	0	0	1,256	1,428	1,049	-	-	380	-	1,429	1	12.1%
2001	1,302	0	0	1,302	1,480	1,049	-	-	-	500	1,549	69	15.9%
2002	1,351	0	0	1,351	1,536	1,049	-	-	-	500	1,549	13	12.8%
2003	1,403	0	0	1,403	1,595	1,049	-	50	-	500	1,599	4	12.3%
2004	1,458	0	0	1,458	1,657	1,049	-	110	-	500	1,659	2	12.1%
2005	1,516	0	0	1,516	1,723	1,049	-	175	-	500	1,724	1	12.1%
2006	1,577	0	0	1,577	1,792	1,049	-		-		1,049	-743	-50.3%
2007	1,641	0	0	1,641	1,865	1,049	-		-		1,049	-816	-56.4%
2008	1,708	0	0	1,708	1,941	1,049	-		-		1,049	-892	-62.8%

Footnotes of forecasted data:

Minimum Capacity Margin (MCM) =	12.00%
Total System Capacity Resp. =	

$$\frac{\text{Total System Peak Resp.}}{1 - \text{MCM} + .00005} + .499$$

0.1304

Empire SLCC as EWG
Annual Ownership and Operating Cost

			Annual Cost $x1,000		
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
<u>SLCC Fixed Expenses</u>					
Gas Reservation Cost		7,681	7,681	7,681	7,681
Labor		1,214	1,245	1,276	1,308
General & Admn		353	362	371	380
Insurance		883	905	928	951
Outside Services		221	226	232	238
Environmental Compliance		110	113	116	119
Fixed Non-CCT Maintenance		442	453	464	475
Total Fixed Expenses		10,904	10,985	11,067	11,152
CC Ownership Cost @ $440/kw		33,600	33,600	33,600	33,600
Xmission Ownership Cost		1,985	1,985	1,985	1,985
Total SLCC Annual Fixed Costs		46,490	46,570	46,653	46,737
MPS Share of SLCC Costs		23,245	23,285	23,326	23,369
Aquila Capacity Payment	4,866				
SEC Capacity Payment	6,984				
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost		8,802	9,022	18,495	18,958
Short Term Peaking Capacity Cost		1,890	4,982		3,489
Gas Reservation Cost		1,920	1,920	3,841	3,841
Total Fixed Cost	19,026	35,857	39,209	45,662	49,656
Energy Cost	85,054	92,399	97,698	103,300	110,319
Total Cost	104,080	128,256	136,907	148,963	159,975

Empire SLCC as Rate Base Asset
Annual Ownership and Operating Cost

		Annual Cost $x1,000			
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
SLCC Fixed Expenses					
Gas Reservation Cost		7,681	7,681	7,681	7,681
Labor		1,214	1,245	1,276	1,308
General & Admn		353	362	371	380
Insurance		883	905	928	951
Outside Services		221	226	232	238
Environmental Compliance		110	113	116	119
Fixed Non-CCT Maintenance		442	453	464	475
Total Fixed Expenses		10,904	10,985	11,067	11,152
CC Ownership Cost @ $440/kw		36,552	35,886	35,213	34,534
Xmission Ownership Cost		2,160	2,121	2,081	2,041
Total SLCC Annual Fixed Costs		49,616	48,991	48,362	47,726
MPS Share of SLCC Costs		24,808	24,496	24,181	23,863
Aquila Capacity Payment	4,866				
SEC Capacity Payment	6,984				
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost		8,802	9,022	18,495	18,958
Short Term Peaking Capacity Cost		1,890	4,982		3,489
Gas Reservation Cost		3,841	3,841	7,681	7,681
Total Fixed Cost	19,026	39,341	42,340	50,357	53,991
Energy Cost	85,054	92,399	97,698	103,300	110,319
Total Cost	104,080	131,740	140,038	153,657	164,310

Aquila Purchase
Annual Ownership and Operating Cost

	Annual Cost $x1,000					
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-05
To>	May-01	May-02	May-03	May-04	May-05	May-06
Aquila Capacity Payment	4,866	19,136	29,760	29,760	29,760	34,200
SEC Capacity Payment	6,984	6,693				
Union Electric Capacity Payment	7,176					
Long Term Peaking Capacity Cost						9,716
Short Term Peaking Capacity Cost				2,837	6,397	1,490
Gas Reservation Cost		5,761	5,761	5,761	5,761	9,361
Total Fixed Costs	19,026	31,590	35,521	38,357	41,917	54,767
Energy Costs	85,007	96,987	101,104	106,038	111,739	117,442
Total Cost	104,034	128,577	136,625	144,396	153,656	172,209

Houston Industries Purchase
Annual Ownership and Operating Cost

	Annual Cost $x1,000					
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-05
To>	May-01	May-02	May-03	May-04	May-05	May-06
Houston Capacity Payment		23,576	23,576	23,576	23,576	23,576
Aquila Capacity Payment	4,866					
SEC Capacity Payment	6,984					
Union Electric Capacity Payment	7,176					
Long Term Peaking Capacity Cost						9,716
Short Term Peaking Capacity Cost				2,837	6,397	1,490
Gas Reservation Cost		7,200	7,200	7,200	7,200	10,800
Total Fixed Costs	19,026	30,776	30,776	33,613	37,173	45,582
Energy Costs	85,071	90,996	98,070	104,456	111,121	115,780
Total Cost	104,098	121,772	128,846	138,069	148,294	161,362

AQUILA PROPOSAL

Aquila Proposal

ENERGY GENERATED (MWH)
PAGE: 1

SOURCE	2000	2001	2002	2003	2004	2005
GENERATING UNITS						
A SIBLEY 1	293,345	259,525	249,733	239,910	273,556	257,404
AQP CC 1	0	513,751	1,463,287	1,474,808	1,509,321	1,511,270
AQP CC 2	0	148,560	724,303	675,850	757,131	752,797
AQP PKR 1	0	271,789	0	0	0	0
AQP PKR 2	0	250,783	0	0	0	0
B SIBLEY 2	275,738	224,801	214,602	209,398	257,748	225,311
C SIBLEY 3	2,447,679	1,961,512	1,424,977	1,579,993	1,324,255	1,460,398
D JEFFREY 1	366,149	337,767	302,763	306,744	314,505	290,059
E JEFFREY 2	411,676	363,133	356,317	319,995	355,875	352,507
F JEFFREY 3	395,279	352,442	318,369	343,711	354,035	345,963
G R. GREEN 3	15,241	9,412	10,189	12,481	15,805	19,728
H GREENWOOD 1	25,957	13,292	12,380	17,040	17,805	27,799
I GREENWOOD 2	22,632	9,964	11,457	13,236	14,115	20,047
J GREENWOOD 3	19,470	9,469	10,085	11,950	11,854	17,914
K GREENWOOD 4	6,854	4,296	4,523	5,112	5,686	9,939
L NEVADA 1	300	130	123	162	146	1,912
M KCI 1	1,454	1,008	973	909	1,193	1,272
N KCI 2	1,250	860	893	955	1,049	931
PKPPA 150 2005	0	0	0	0	0	406,466
PURCHASES						
AQUILA 135 2000	0	0	0	0	0	0
AQUILA SHTRM PK	0	0	0	107,226	260,194	29,882
EMERGENCY	12	1	16	6	0	113
SEC 120 2000	18,204	0	0	0	0	0
SPOT	434,656	550,709	316,829	266,548	247,445	139,491
UE	410,196	0	0	0	0	0
TOTAL	5,146,091	5,283,203	5,421,819	5,586,033	5,721,718	5,871,201
Units	4,283,024	4,732,493	5,104,974	5,212,253	5,214,079	5,701,715
Purchases	863,067	550,710	316,845	373,780	507,640	169,485

SCHEDULE FAD-20
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FUEL EXPENSE ($)
PAGE: 1

SOURCE	2000	2001	2002	2003	2004	2005
GENERATING UNITS						
A SIBLEY 1	4,090,473	3,771,011	3,733,053	3,634,377	4,187,595	4,021,459
AQP CC 1	0	9,486,499	26,448,441	27,039,400	27,782,422	28,498,953
AQP CC 2	0	2,533,516	12,283,175	11,573,124	13,092,469	13,636,818
AQP PKR 1	0	6,752,305	0	0	0	0
AQP PKR 2	0	6,219,336	0	0	0	0
B SIBLEY 2	4,040,125	3,432,888	3,370,571	3,333,765	4,148,585	3,704,920
C SIBLEY 3	28,341,906	23,879,701	18,345,760	20,508,049	17,361,135	19,624,305
D JEFFREY 1	5,373,906	5,521,274	5,468,598	5,859,009	6,084,469	5,234,016
E JEFFREY 2	6,016,343	5,874,241	6,301,742	6,018,075	6,751,493	6,192,099
F JEFFREY 3	5,837,975	5,728,357	5,644,306	6,541,196	6,806,442	6,141,727
G R. GREEN 3	428,689	272,013	301,615	375,758	483,234	618,861
H GREENWOOD 1	730,401	386,427	365,673	515,968	546,937	883,642
I GREENWOOD 2	635,529	289,863	339,820	399,974	434,202	640,018
J GREENWOOD 3	546,597	275,380	300,693	361,220	364,659	566,428
K GREENWOOD 4	262,003	150,588	163,397	190,869	211,720	353,161
L NEVADA 1	16,791	8,248	8,139	10,920	9,929	138,135
M KCI 1	49,200	34,825	34,416	32,829	43,708	47,985
N KCI 2	44,596	31,686	33,958	37,171	40,877	37,340
PKPPA 150 2005	0	0	0	0	0	11,483,519
TOTAL	56,414,535	74,648,158	83,143,355	86,431,705	88,349,876	101,823,385

Aquila Proposal

Total Expense ($)
PAGE: 1

SOURCE	2000	2001	2002	2003	2004	2005
GENERATING UNITS						
A SIBLEY 1	4,706,497	4,316,012	4,257,493	4,138,189	4,762,063	4,562,008
AQP CC 1	0	10,195,474	28,486,145	29,144,287	29,990,918	30,764,305
AQP CC 2	0	2,738,528	13,288,572	12,533,395	14,197,229	14,762,944
AQP PKR 1	0	7,119,221	0	0	0	0
AQP PKR 2	0	6,557,895	0	0	0	0
B SIBLEY 2	4,619,173	3,904,971	3,821,235	3,773,501	4,689,856	4,178,072
C SIBLEY 3	32,992,488	27,606,588	21,053,219	23,510,027	19,877,211	22,399,057
D JEFFREY 1	6,472,353	6,534,576	6,376,888	6,779,241	7,027,987	6,104,194
E JEFFREY 2	7,251,370	6,963,637	7,370,692	6,978,061	7,819,120	7,249,618
F JEFFREY 3	7,023,809	6,785,681	6,599,414	7,572,328	7,868,548	7,179,615
G R. GREEN 3	504,896	319,072	352,562	438,161	562,261	717,503
H GREENWOOD 1	860,187	452,885	427,575	601,169	635,960	1,022,635
I GREENWOOD 2	748,691	339,686	397,106	466,156	504,776	740,252
J GREENWOOD 3	643,947	322,726	351,116	420,968	423,930	655,998
K GREENWOOD 4	296,274	172,066	186,012	216,427	240,149	402,854
L NEVADA 1	18,291	8,899	8,752	11,730	10,658	147,695
M KCI 1	63,744	44,904	44,148	41,918	55,641	60,708
N KCI 2	57,097	40,287	42,885	46,725	51,363	46,652
PKPPA 150 2005	*0*	*0*	*0*	*0*	*0*	*11,934,696*
PURCHASES						
AQUILA 135 2000	0	0	0	0	0	0
AQUILA SHTRM PK	0	0	0	2,723,802	6,763,478	797,290
EMERGENCY	908	45	1,233	428	0	8,445
SEC 120 2000	711,397	0	0	0	0	0
SPOT	10,293,112	12,564,262	8,038,917	6,641,808	6,257,845	3,707,782
UE	7,743,036	0	0	0	0	0
TOTAL	85,007,270	96,987,414	101,103,963	106,038,319	111,738,991	117,442,325
Units	66,258,818	84,423,107	93,063,812	96,672,282	98,717,669	112,928,807
Purchases	18,748,452	12,564,307	8,040,151	9,366,037	13,021,322	4,513,518

SCHEDULE FAD-20
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