NorAm/Houston Industries

POWER MARKETING DEPARTMENT

1111 LOUISIANA STREET, 8th FLOOR
HOUSTON, TX 77002

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

MEMO

DATE: 7.2.98

TO: Kiah Harris

CO.: Burns & McDonnell

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

RE: Utilicorp RFP dated 5.22.98 for Capacity and Energy for MPS

Houston Industries is interested in discussing its plans for owning and operating generation in the Midwest with Utilicorp. We are responding to the RFP with an indicative proposal at this time. We will soon announce the construction of a large generating station in an area that could provide Capacity and Energy to Utilicorp for MPS. We would welcome the opportunity to meet with you and Utilicorp after that announcement to see how we can arrive at a mutually beneficial relationship. Please contact me after you discuss this possibility with Utilicorp.

PROPOSAL **CONFIDENTIAL**

NorAm Energy Services (NES) offers the following indicative proposal to Utilicorp Energy Group for delivery of Capacity and Energy to Missouri Public Service Company (MPS) as a result of the Resource Specific Capacity and Energy RFP issued May 22, 1998. Houston Industries (HI), the parent company of NES, anticipates the announcement a merchant plant to be constructed in the Midwest in the near future. Construction of that plant will allow NES to name a specific source for Capacity and Energy as required by the RFP.

Capacity Pricing:

Contract Period	Annual Capacity	$/MW-mo
6/1/2001 to 5/31/2002	100MWs	8500
6/1/2002 to 5/31/2003	100MWs	8750
6/1/2003 to 5/31/2004	100MWs	9000

Energy Pricing:

Contract Period	Annual Load Factor	$/MWh
6/1/2001 to 5/31/2002	100%	22.00
6/1/2002 to 5/31/2003	100%	22.50
6/1/2003 to 5/31/2004	100%	23.00

The Point of Delivery shall be at an interconnection point of the MPS transmission system.

NES shall arrange for firm transmission from its source to the Point of Delivery. The transmission price shall be passed through to MPS at cost and with no profit to NES.

For purposes of this indicative proposal, NES is not interested in discussing buyout options or guaranteed availability. NES and Houston Industries Power Generation (HIPG) are definitely interested in discussing our plans for generation assets in the Midwest and Utilicorp's future needs for Capacity and Energy. We would appreciate the opportunity to discuss these issues outside the RFP process. We will keep you informed of our progress on this particular generation project. The possibility exists that we could offer more Capacity and Energy from this plant or others that might be constructed.

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 so that we can begin detailed discussions soon. And thanks again for the opportunity to respond. I'll look forward to hearing from you.

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.

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)

Recd: 1/6/99 1100

UtiliCorp United d.b.a. MPS

8:02 PM 01/05/99
For Discussion Only

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.

NP Energy

Michael L. McInnis
Senior Vice President

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

502.560.5312
502.560.5310 Fax
mmcinnis@npenergy.com

January 7, 1999

Mr. Robert W. Holzwarth
Vice President and General Manager
Utilicorp Energy Group
10700 East 350 Highway
Kansas City, MO 64138

Dear Mr. Holzwarth:

Please be advised that NP Energy ("NPE") assigned all of its rights, respecting the NPE power generation proposal to Missouri Public Service, to Houston Power Generation, Inc. on November 2, 1998. Should you have any questions concerning this assignment, please contact me at (502) 560-5312.

Very truly yours,

cc: T. P. Naulty, Houston Industries

NP Energy

Jack L. Farley, Jr.
Vice President.
Marketing

Energy

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

502.560.5340
502.560.5310 Fax
jfarley@npenergy.com

July 2, 1998

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

Subject: Response to Resource Specific Capacity & Energy for Missouri Public Service

Dear Mr. Harris:

NP Energy Inc. ("NPE") is pleased to present this 3-year proposal to provide 100 MW of capacity and energy to Missouri Public Service ("MPS"). This proposal provides MPS capacity at an attractive price, and energy at market rates. NPE is prepared to discuss other alternatives, such as extension options or a different quantity, if this base proposal is of interest to MPS.

The capacity that NPE is bidding in this proposal will be supplied through its contract with a plant that will be built in the Public Service Company of Oklahoma's control area. NPE is entering into a power purchase and sale agreement with the developers, pursuant to which NPE will have the exclusive right to purchase all of the output. The expected commencement date of plant's operations is June 1, 2001. If MPS is interested in this proposal, NPE will provide more information regarding the project and the developers. This proposal, and any ultimate purchase and sale agreement, is contingent upon successful completion of the plant.

NPE is a leading power marketer, active in all markets throughout the U.S. NPE is a venture between an employee group and National Power PLC of Great Britain. More information concerning NPE and National Power is included in the attached information.

This proposal is subject to the successful completion of due diligence, the successful negotiation, approval, and execution of a mutually agreeable definitive agreement, and NP Energy Inc. Board of Director approval. In addition, this proposal is contingent upon the plant being built.

Thank you in advance for your consideration of our proposal. Any questions should be directed to the undersigned at (502) 560-5366.

Sincerely,

Attachments

NP Energy Inc.
Proposal Prepared for MPS Resource Specific RFP
July 2, 1998

TIME PERIOD:

Start Date: June 1, 2001
End Date: May 31, 2004

CAPACITY:

SPP Accredited: Yes
Quantity: 100 MW
Price: $2.50/kW-month; no escalation

ENERGY PRICE:

MPS will have the ability to buy energy at market-based prices during all hours of the term

LOCATION

The capacity resource is located within the Public Service Company of Oklahoma's control area; The energy will be delivered to NPE's choice of MPS interface (or load control aggregate)

SCHEDULING:

MPS must notify NPE by 8:00 AM CPT the day prior to delivery for day-ahead schedules, or by 30 minutes prior to the hour of delivery for hourly schedules

TRANSMISSION:

If MPS chooses to reserve firm transmission associated with the capacity, an additional fee of $3.40/MWh plus 4% losses will be required (under current SPP tariff).

BUYOUT PROVISION:

MPS has the sole and exclusive right to buyout the contract at a fixed fee no later than a specific date (see dates and fees below). If MPS elects a buyout then MPS pays the buyout fee with 15 days and thereafter would not receive the capacity rights and would not pay the capacity price.

June 1, 2002: $3,000,000
June 1, 2003 $1,500,000

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

November 6, 1998

UTILICORP UNITED
ENERGYONE

Sherry M. Perchik
NP Energy
3650 National City Tower
Louisville KY 40202

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

Dear Sherry:

As you know, your firm's proposal was one of eight received by UtiliCorp in response to the above referenced RFP. In my August 25th letter I indicated that at that time UtiliCorp had planned to complete its analysis of the proposals by mid-September. Due to both internal and external circumstances the analysis was not completed as contemplated. UtiliCorp will now complete its analysis by mid-December.

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 contact me as soon as possible if your firm continues to have an interest in providing power supply resources to MPS so that the details of your proposal may be finalized.

In order for your firm's proposal to continue to be considered, a response to this letter must be received no later than 5:00 PM, November 13, 1998.

Sincerely yours,

Frank A. DeBacker

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

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,

FAX 1-502-560-5310

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
~$4.25 m 10/28/98

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

Southern Company

Southern Company
Energy Marketing L.P.
200 Westlake Park Blvd
Suite 200
Houston, Texas 77079

Tel 281 584.3900
800.334.2726
Fax 281.584.3901

SOUTHERN COMPANY
Energy to Serve Your World™

July 2, 1998

PRIVATE & CONFIDENTIAL

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

Subject: Capacity and Energy Purchase Proposal

This document represents possible terms under which Southern Company Energy Marketing "SCEM" would provide capacity and energy to Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU) per UCU's Request for Proposal (RFP) issued May 22, 1998. SCEM proposes to invest in capital assets to respond to MPS's capacity and energy needs from June 1, 2001 through May 31, 2004. SCEM would be receptive to extending the term of this agreement to complement MPS's future capacity and energy requirements. The assumptions and pricing scenarios are included on the following Attachments.

This proposal serves only to set out certain key terms and conditions that SCEM, based upon current market conditions, believes might be agreeable to MPS for inclusion in any final, mutually executed agreement on the subject transaction and, as such, does not constitute an offer nor does it obligate either party to proceed further. Certain additional, material terms would have to be negotiated and agreed upon before either SCEM or MPS would incur any contractual obligations to the other, and such further negotiations may necessitate changes to the terms and conditions set out in this letter.

SCEM appreciates the opportunity to work with MPS on this RFP and future opportunities. We welcome your comments regarding this proposal and any additional services you may require. Should you have questions, please contact me directly at (281) 584-3962.

Very truly yours,

Pat Mann
Manager

cc: Henderson Cosnahan
Ress Young

PRIVATE & CONFIDENTIAL

Non-Binding
Re: Capacity and Energy Purchase Proposal

Missouri Public Service
Kiah Harris
July 2, 1998

Pricing Proposal

Contract Term:	June 1, 2001 through May 31, 2004	
Capacity:	100 MW	
Price:	**Capacity**	$2,650/MW-mo or $31,800/MW-year in year 2001 dollars escalating @ 3.25%/year
	Energy	8350 BTU/kwh plus $0.225/MWh variable O&M
	Gas	First of month Index for Henry Hub as published in "Inside FERC" plus $0.04/MMBtu
	Transmission	Buyer may take delivery from our bus within Entergy's service territory.

Pricing Conditions

- Capacity and Energy is priced on a firm, unit contingent basis;
- A minimum Energy take of 50% is assumed;
- The following calculation will be used to calculate the energy price charge to MPS:

  (Heat Rate x Gas Price)/1000 + Variable O&M Cost = $/MWh

  where: Heat Rate is in BTU/kwh
  Gas is in $/MMBTU
  Variable O&M cost is in $/MWh

- Pricing is based on a unit availability factor of 94%. SCEM will guarantee this availability.
- Any energy purchased for MPS by SCEM to cover forced outages within the 94% unit availability tolerance or any forced outages or transmission constraints that are out of SCEM's control due to conditions of force majeure will be priced at procurement/market prices. SCEM will exercise a good faith effort in securing energy at the most economic price.
- Energy provided to MPS by SCEM during scheduled outages or unscheduled outages outside of the 94% unit availability tolerance will be priced as quoted above. SCEM will provide MPS with an annual maintenance schedule.

Buyout Provision: Buyer shall have the option to purchase their pro rata share of the asset at the then current book value upon June 1, 2002.

Scheduling:
Resource Start up costs - not applicable
Minimum load factor & measuring period - 50% Annual
Maximum load factor & measuring period - 100% of unit availability
Minimum schedule block - 50 MW
Initial schedule submittal procedure - Day ahead preschedule with written confirmation
Subsequent schedule change procedure - 12 hour notice
Energy Block Requirements - Standard On and Off Peak Blocks

Agreement: SCEM and MPS agree to enter into a formal Sales and Purchase Agreement.

Confidentiality: This proposal, the contents hereof, and the transaction contemplated hereby are confidential and will not be disclosed by either party (or their agents), without prior consent of the other party.

Southern Company
Energy Marketing L.P.
200 Westlake Park Blvd.
Suite 200
Houston, Texas 77079

Tel 281.584.3900
800.334.2726
Fax 281.584.3901

September 1, 1998

SOUTHERN COMPANY
Energy to Serve Your World[SM]

UtiliCorp United
10700 East 350 Highway
Kansas City, Missouri 64138

Attn: Frank A. DeBacker

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

Dear Frank:

In response to your letter dated August 25,1998 , Southern Company Energy Marketing L.P. (SCEM) continues to be interested in providing power supply resources to Missouri Public Service (MPS) under the terms expressed in our offer.

Our proposal serves only to set out certain key terms and conditions that SCEM, based upon current market conditions, believes might be agreeable to UtiliCorp United for inclusion in any final, mutually executed agreement on the subject transaction. Certain additional, material terms would have to be negotiated and agreed upon before either SCEM or UtiliCorp United would incur any contractual obligations to the other, and such further negations may necessitate changes to the terms and conditions set out in this letter.

I look forward to working with you towards a final agreement. Please call David Cavazos at 281-584-3945 or myself at 281-584-3962 if you have any questions or comments regarding our offer.

Sincerely,

David H Cavazos

for Pat Mann
Manager

cc: Henderson Cosnahan
David Cavazos

Chronology
of
Supply Side Resource Solicitation Process

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.
September, 1998	UtiliCorp forms Merchant Energy Partners to develop and own Exempt Wholesale Generator (EWG) and Independent Power Producer (IPP) facilities.
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 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.

Chronology
of
Supply Side Resource Solicitation Process

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/Merchant Energy Partners 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 Merchant Energy Partners 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. Received confirmation that Merchant Energy Partners would replace Aquila Power as the owner of the proposed EWG and would be the entity contracting with MPS.
January 7, 1999	Completed evaluation of Houston Industries proposal. Received notice that NP Energy had assigned its proposal to Houston Industries.
January 11, 1999	Meeting with UCU management Group to discuss status of MPS power supply.
January 12, 1999	Merchant Energy Partners submitted revisions to their proposal.

Chronology
of
Supply Side Resource Solicitation Process

January 13, 1999	Notified Houston Industries that their proposal was not competive at present pricing levels and terms and conditions (ie: five year term with no option to reduce purchase amount).
January 14, 1999	Houston responded that they were not able to improve their offer.
January 15, 1999	Notified Houston Industries that they were not successful bidder. Notified Merchant Energy Partners that their proposal was selected as preferred supply option subject to successful negotiation of contract.
January 16, 1999 to Present	Negotiated final terms and conditions of power supply agreement with Merchant Energy Partners.

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February 1, 1999

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals. UtiliCorp United (UCU) provided the proposals and updated offers from Houston Industries (HI) and Merchant Energy Partners (MEP).

The objective of the evaluation was to verify that the information from the proposals had been accurately input into the model. The evaluation was also performed to determine the power supply option which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2005. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU.

Burns & McDonnell verified that the information provided by UCU had been correctly input into the model. Assumptions made in the evaluation of the offers were provided by UCU and included the natural gas price forecasts, spot energy market price forecasts, and energy sales price forecasts. Burns & McDonnell has reviewed these assumptions and determined that they are reasonable.

The results of the RealTime modeling are shown on the attached tables. Both proposals were modeled under a base, low, and high gas price forecast and a base, low, and high energy market price forecast. All cases were run with and without the sale of energy not required by UCU. The energy to be sold could be provided by any available resources in each case modeled.

As shown in the tables, the total expenses of the two proposals were very similar across all of the cases run. The NPV of total costs for the MEP option is slightly less than the HI option in all but one case. The HI proposal was less expensive in the case involving the base gas price forecast, low market energy prices, and no off-system sales.

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We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

Missouri Power Supply
Bid Comparison
6/1/2000 - 5/31/2005
$x1,000

	Annual Cost $x1,000					NPV
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-00
To>	May-01	May-02	May-03	May-04	May-05	May-05
Without Off System Sales						
Base Gas & Mkt						
Merchant Energy Partners	108,388	130,053	135,381	143,952	154,103	530,017
Houston Industries	108,388	129,074	136,181	145,432	156,081	532,248
Low Gas & Mkt						
Merchant Energy Partners	107,201	128,131	133,679	141,514	150,536	521,700
Houston Industries	107,201	127,071	133,707	142,439	152,179	522,611
High Gas & Mkt						
Merchant Energy Partners	109,286	131,741	136,817	145,969	157,239	537,054
Houston Industries	109,287	130,352	138,055	147,781	159,531	539,738
Base Gas & High Mkt						
Merchant Energy Partners	109,286	131,611	136,202	144,902	155,416	534,428
Houston Industries	109,287	130,372	137,863	147,227	158,542	538,522
Base Gas & Low Mkt						
Merchant Energy Partners	107,201	128,216	134,081	142,533	152,026	523,854
Houston Industries	107,201	127,093	133,884	142,788	152,650	523,348
With Off System Sales						
Base Gas & Mkt						
Merchant Energy Partners	104,398	124,280	125,783	135,176	145,695	501,582
Houston Industries	104,496	123,971	132,218	141,965	152,742	516,301
Low Gas & Mkt						
Merchant Energy Partners	104,900	124,198	127,032	135,426	144,548	502,371
Houston Industries	105,051	123,833	131,134	140,080	149,887	512,508
High Gas & Mkt						
Merchant Energy Partners	103,334	123,486	123,798	134,399	146,379	498,234
Houston Industries	103,366	122,870	132,193	143,092	155,022	516,671
Base Gas & High Mkt						
Merchant Energy Partners	103,334	123,245	122,774	132,659	143,683	494,100
Houston Industries	103,366	122,768	131,681	142,090	153,522	514,421
Base Gas & Low Mkt						
Merchant Energy Partners	104,900	124,319	127,710	136,885	146,458	505,385
Houston Industries	105,051	123,918	131,452	140,701	150,685	513,833

Merchant Energy Partners
Annual Ownership and Operating Cost
$x1,000

	Annual Fixed Cost				
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Aquila Capacity Payment	4,866				
MEP Capacity Payment		17,696	27,660	27,660	27,660
SEC Capacity Payment	7,566	6,693			
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		6,890	6,890	6,890	6,890
Total Fixed Costs	19,608	31,279	34,550	37,387	40,947

	Total Annual Supply Cost				
Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,779	98,774	100,831	106,565	113,157
Total Cost	108,388	130,053	135,381	143,952	154,103
MWh $ w/Low Gas & Mkt	87,592	96,852	99,129	104,127	109,589
Total Cost	107,201	128,131	133,679	141,514	150,536
MWh $ w/ High Gas & Mkt	89,678	100,462	102,267	108,582	116,293
Total Cost	109,286	131,741	136,817	145,969	157,239
MWh $ w/Base Gas & High Mkt	89,678	100,332	101,652	107,515	114,469
Total Cost	109,286	131,611	136,202	144,902	155,416
MWh $ w/Base Gas & Low Mkt	87,592	96,937	99,531	105,146	111,079
Total Cost	107,201	128,216	134,081	142,533	152,026
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,789	93,001	91,233	97,790	104,748
Total Cost	104,398	124,280	125,783	135,176	145,695
MWh $ w/Low Gas & Mkt	85,292	92,919	92,482	98,040	103,601
Total Cost	104,900	124,198	127,032	135,426	144,548
MWh $ w/ High Gas & Mkt	83,725	92,207	89,248	97,012	105,433
Total Cost	103,334	123,486	123,798	134,399	146,379
MWh $ w/Base Gas & High Mkt	83,725	91,966	88,224	95,272	102,736
Total Cost	103,334	123,245	122,774	132,659	143,683
MWh $ w/Base Gas & Low Mkt	85,292	93,040	93,160	99,498	105,511
Total Cost	104,900	124,319	127,710	136,885	146,458

Houston Industries
Annual Ownership and Operating Cost
$x1,000

			Annual Fixed Cost		
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Houston Capacity Payment		23,576	23,576	23,576	23,576
Aquila Capacity Payment	4,866				
SEC Capacity Payment	7,566				
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		8,755	8,755	8,755	8,755
Total Fixed Costs	19,608	32,331	32,331	35,168	38,728

			Total Annual Supply Cost		
Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,780	96,743	103,850	110,264	117,353
Total Cost	108,388	129,074	136,181	145,432	156,081
MWh $ w/Low Gas & Mkt	87,592	94,740	101,375	107,271	113,451
Total Cost	107,201	127,071	133,707	142,439	152,179
MWh $ w/ High Gas & Mkt	89,678	98,021	105,724	112,613	120,803
Total Cost	109,287	130,352	138,055	147,781	159,531
MWh $ w/Base Gas & High Mkt	89,678	98,041	105,531	112,059	119,814
Total Cost	109,287	130,372	137,863	147,227	158,542
MWh $ w/Base Gas & Low Mkt	87,592	94,761	101,553	107,620	113,922
Total Cost	107,201	127,093	133,884	142,788	152,650
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,888	91,639	99,886	106,797	114,014
Total Cost	104,496	123,971	132,218	141,965	152,742
MWh $ w/Low Gas & Mkt	85,442	91,501	98,802	104,912	111,159
Total Cost	105,051	123,833	131,134	140,080	149,887
MWh $ w/ High Gas & Mkt	83,757	90,539	99,861	107,924	116,293
Total Cost	103,366	122,870	132,193	143,092	155,022
MWh $ w/Base Gas & High Mkt	83,757	90,437	99,349	106,922	114,794
Total Cost	103,366	122,768	131,681	142,090	153,522
MWh $ w/Base Gas & Low Mkt	85,442	91,587	99,120	105,533	111,957
Total Cost	105,051	123,918	131,452	140,701	150,685

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August 21, 1998

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals made in response to the request for proposals (RFP) issued by Utilicorp United (UCU). The proposals were opened on July 6, 1998 with representatives of UCU and Burns & McDonnell in attendance. Proposals were received from the following companies in alphabetical order:

- Aquila Power Corporation (Aquila)
- Basin Electric Power Cooperative (Basin)
- Carolina Power & Light Company (CP&L)
- LS Power, LLC (LS Power)
- NorAm Energy Services (NorAm)
- NP Energy, Inc. (NP Energy)
- Southern Company Energy Marketing (Southern)
- Southwestern Public Service Company (SPS)

The objective of the evaluation was to determine the power supply option or combination of power supply options which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2004. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU. Assumptions made in the evaluation of the offers are listed in Table 1. This list of assumptions includes all information used in the modeling that was not specifically provided in the offers.

Combinations of the power supply options were made as necessary to minimize total expenses and meet the capacity requirements of UCU in the evaluation period. The timing and combinations of offers for the lowest cost cases are shown in Table 2 at the end of the report. Each case was run under two different scenarios. The first scenario allowed the energy not required by UCU to be sold. The sale price used in the model for

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this surplus energy was the spot market price of energy less $2.00/MWh. The spot market energy price forecast and the adjustment for the energy sales prices were provided by UCU. The energy to be sold could be provided by any available resources in each case modeled. The second scenario did not take into account the sale of surplus energy.

Table 3 shows the results of the RealTime modeling for the scenario with energy sales. The cases shown in the table represent the lowest cost cases developed by Burns & McDonnell. The lowest cost option includes a combination of purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the study period and the addition of 500 MW of combined cycle capacity by UCU on June 1, 2001. This combination of resources results in total expenses of $391,167,001, approximately $25 million less than the next least expensive case which includes the same purchases and combined cycle units offered by LS Power.

The relative cost rankings change considerably if sales are not taken into consideration as shown in Table 4. The lowest cost case without sales of excess energy includes purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the evaluation period and purchases from CP&L, Southern, NP Energy, and Aquila over the remaining three years. The case including the addition of combined cycle units by UCU has total expenses of approximately $7 million more than the least cost case over the evaluation period.

We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

Daniel A. Froelich

Daniel A. Froelich, P.E.
Vice President

James M. Flucke

James M. Flucke, P.E.
Project Manager

Table 1
Assumptions Made for RealTime Modeling

Evaluation period - June 1, 2000 to May 31, 2004.
Capacity and demand forecasts for 2001-2004 provided by Utilicorp.
Spot market energy price forecast provided by Utilicorp.
MPS internal wheeling charges are assumed to the same for both generation built internal to the MPS transmission system and power delivered from outside the MPS transmission system.
MPS natural gas price forecast provided by MPS equals Henry Hub Index price forecast minus $0.09/mmBtu plus $0.35/mmBtu in transmission charges.
At the direction of Utilicorp, peaking capacity assumed to be available for $4.00/kW-mo.
Sales of excess energy were made at the spot market energy price less $2.00/MWh.
Information on 55 MW unit-contingent purchase provided by Utilicorp.

Aquila
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

Basin Electric Power Cooperative

Carolina Power & Light
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed contract could start on June 1, 2001.

LS Power
The effect of the 10-year contract beyond the evaluation period has not been taken into consideration.
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed Availability Adjustment Factor equal to one for the second and third years of the contract.
Gross Domestic Price Deflator assumed to equal three percent.

NorAm
Transmission charge of $998/MW-mo. based on present Ameren transmission charges and $1.37/MWh provided by NorAm. .

NP Energy
Market based hourly energy price forecast provided by Utilicorp.
Transmission charge of $2,497/MW-mo. provided by Utilicorp.
Assumed losses of 4.2% for both capacity and energy price provided by Utilicorp.
Energy price equals market based price forecast plus $3.40/MWh in transmission charges plus 4.2% losses.

Southern Company
Cost of natural gas assumed to be equal to Henry Hub Index price forecast provided by Utilicorp.
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

SPS
Option A assumed to be available for a one-year term based on discussions with Utilicorp.
Assumed transmission charges equal to $4,033/MW-mo. provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.
Assumed losses of 8.05% for both capacity and energy provided by Utilicorp.

Utilicorp United
Fuel costs based on heat rate curves and natural gas price forecasts provided by Utilicorp.
Combined-cycle capacity addition of 500 MW on June 1, 2001.
Capacity charge of $5.50/kW-mo with no escalation assumed for CC units based on discussions with Utilicorp.
Operation & Maintenance cost forecast provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.

Table 2
Case 1 Description

Case 1		Evaluation Period			
		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540		540	540	540
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	540	540	540
Excess Capacity (MW)		0	135	100	60

Table 2 (Cont.)
Case 2 Description

Case 2		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500		500	500	500
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	500	500	500
Excess Capacity (MW)		0	95	60	20

Table 2 (Cont.)
Case 3 Description

Case 3		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4 Description

Case 4		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	✓ 100			
Aquila 1b	75	✓ 75			
Aquila 3	100				
SPS A	75-100	✓ 75	100	100	100
SPS Peak	25	✓ 25			
Basin	<=100				
NP Energy	100	✓	100	100	100
Southern	100	✓	100	100	100
CP&L	150	✓	150	150	150
NORAM	100				
Unit-Contingent Purchase	55	✓ 55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4a Description

Case 4a		Evaluation Period			
		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4b Description

Case 4b		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 5 Description

Case 5		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100				
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 6 Description

Case 6		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 2 (Cont.)
Case 7 Description

Case 7		Evaluation Period			
		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
CP&L	150				
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 3
RealTime Modeling Results with Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,918						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Sales		-9,638,472	-$244,101,124						
Case 2					$ 56,009,906	-$229,989,146	$ 565,146,241	$ 391,167,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 148,501,561						
	Utilicorp Unit 2 (Online 2001)	250	4,741,587	$ 138,812,149						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,389						
	Sales		-9,294,721	-$229,989,146						
Case 3					$ 258,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,650						
	Southern	100	2,040,278	$ 59,698,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,732,666	$ 97,758,915						
	(Peaking Capacity)	25	11,069	$ 1,730,085						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,670	$ 35,079,240						
	Southern	100	2,035,607	$ 59,600,970						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,381,984
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,988,898						
	NP Energy	100	19,268	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Partial Requirement)	75	347,040	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,010						
Case 4b					$ 245,656,954	-$104,544,438	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	269,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,336						
	NP Energy	100	6,746	$ 18,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,438						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,368,588						
	NP Energy	100	18,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,800	$ 18,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,938,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-5,553,100	-$140,445,134						

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

Table 4
RealTime Modeling Results without Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 247,482,085	$ 228,719,801	$ 476,201,886	4.9%	$ 22,182,486
	LS Power Unit 1 (Online 2001)	270	3,450,651	$ 128,875,814					
	LS Power Unit 2 (Online 2001)	270	1,159,977	$ 79,414,823					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,016,014					
Case 2					$ 44,330,926	$ 423,308,758	$ 467,639,684	3.0%	$ 13,620,284
	Utilicorp Unit 1 (Online 2001)	250	3,380,441	$ 120,708,610					
	Utilicorp Unit 2 (Online 2001)	250	1,379,094	$ 77,788,906					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	147	$ 4,814,017					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199					
	SPS Option A (Parital Requirement)	75	174,554	$ 12,397,030					
	(Peaking Capacity)	25	11,078	$ 1,731,887					
	Unit-Contingent Purchase	55	9,850	$ 3,018,109					
Case 3					$ 196,163,051	$ 264,990,950	$ 461,154,001	1.6%	$ 7,134,601
	CP&L	150	69,963	$ 28,773,330					
	Southern	100	940,495	$ 36,572,069					
	Aquila Option 3	100	153	$ 24,373,182					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,422,437	$ 71,756,138					
	(Peaking Capacity)	25	10,905	$ 1,723,749					
	Unit-Contingent Purchase	55	9,891	$ 3,019,083					
	Peaking Contract		0	$ 1,440,000					
Case 4					$ 190,167,020	$ 264,956,444	$ 455,123,464	0.2%	$ 1,104,064
	CP&L	150	67,346	$ 28,689,735					
	Southern	100	935,112	$ 36,457,450					
	NP Energy	100	8,090	$ 18,644,079					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,423,251	$ 71,770,828					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4a					$ 173,655,923	$ 280,363,477	$ 454,019,400	0.0%	$ -
	CP&L	150	128,230	$ 30,595,167					
	Southern	100	1,272,189	$ 43,749,960					
	NP Energy	100	19,468	$ 19,007,529					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	Aquila 3	100	131	$ 24,370,845					
	SPS Option A (Parital Requirement)	75	173,579	$ 12,375,423					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4b					$ 190,348,728	$ 270,494,040	$ 460,842,768	1.5%	$ 6,823,368
	CP&L	150	65,557	$ 28,633,893					
	Southern	100	1,279,851	$ 43,918,072					
	NP Energy	100	6,758	$ 18,593,725					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	NorAm	100	647,710	$ 51,208,572					
	SPS Option A (Parital Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,016,014					
	Peaking Contract		0	$ 1,440,000					
Case 5					$ 191,200,852	$ 278,177,382	$ 469,378,234	3.4%	$ 15,358,834
	CP&L	150	125,345	$ 30,504,582					
	Aquila Option 3	100	131	$ 24,370,845					
	NP Energy	100	18,990	$ 18,991,617					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,525,643	$ 73,874,603					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 6					$ 192,988,455	$ 265,108,518	$ 458,096,973	0.9%	$ 4,077,573
	Aquila Option 3	100	196	$ 24,377,567					
	NP Energy	100	14,527	$ 18,899,618					
	Southern	100	935,112	$ 36,457,442					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,423,244	$ 71,770,683					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					
Case 7					$ 214,582,569	$ 257,622,027	$ 472,204,596	4.0%	$ 18,185,196
	Southern	100	941,572	$ 36,595,807					
	Aquila Option 3	100	196	$ 24,377,567					
	NorAm	100	390,664	$ 44,985,611					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,426,397	$ 71,834,585					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

"Look Date" 1-Dec-98

Greenwood Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.05	0.01		1.964
February	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
March	2.01	-0.13	1.88	0.046427	0.05	0.01		1.986
April	2.00	-0.13	1.87	0.04618	0.05	0.01		1.976
May	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
June	2.02	-0.13	1.888	0.046624	0.05	0.01		1.995
July	2.03	-0.13	1.9	0.046921	0.05	0.01		2.007
August	2.04	-0.13	1.912	0.047217	0.05	0.01		2.019
September	2.06	-0.13	1.925	0.047538	0.05	0.01		2.033
October	2.11	-0.13	1.98	0.048896	0.05	0.01		2.089
November	2.25	-0.13	2.122	0.052403	0.05	0.01		2.234
December	2.40	-0.13	2.275	0.056181	0.05	0.01		2.391

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.05	0.01		2.453
February	2.36	-0.13	2.23	0.055070	0.05	0.01		2.345
March	2.25	-0.13	2.12	0.052354	0.05	0.01		2.232
April	2.17	-0.13	2.04	0.050378	0.05	0.01		2.150
May	2.14	-0.13	2.01	0.049637	0.05	0.01		2.120
June	2.14	-0.13	2.007	0.049563	0.05	0.01		2.117
July	2.14	-0.13	2.014	0.049736	0.05	0.01		2.124
August	2.15	-0.13	2.021	0.049909	0.05	0.01		2.131
September	2.15	-0.13	2.025	0.050008	0.05	0.01		2.135
October	2.18	-0.13	2.055	0.050749	0.05	0.01		2.166
November	2.32	-0.13	2.188	0.054033	0.05	0.01		2.302
December	2.46	-0.13	2.333	0.057614	0.05	0.01		2.451

"Look Date" 1-Dec-98

RG3 Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.25	0.01		2.164
February	2.02	-0.13	1.885	0.04655	0.25	0.01		2.192
March	2.01	-0.13	1.88	0.046427	0.25	0.01		2.186
April	2.00	-0.13	1.87	0.04618	0.25	0.01		2.176
May	2.02	-0.13	1.885	0.04655	0.25	0.01		2.192
June	2.02	-0.13	1.888	0.046624	0.25	0.01		2.195
July	2.03	-0.13	1.9	0.046921	0.25	0.01		2.207
August	2.04	-0.13	1.912	0.047217	0.25	0.01		2.219
September	2.06	-0.13	1.925	0.047538	0.25	0.01		2.233
October	2.11	-0.13	1.98	0.048896	0.25	0.01		2.289
November	2.25	-0.13	2.122	0.052403	0.25	0.01		2.434
December	2.40	-0.13	2.275	0.056181	0.25	0.01		2.591

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.25	0.01		2.653
February	2.36	-0.13	2.23	0.055070	0.25	0.01		2.545
March	2.25	-0.13	2.12	0.052354	0.25	0.01		2.432
April	2.17	-0.13	2.04	0.050378	0.25	0.01		2.350
May	2.14	-0.13	2.01	0.049637	0.25	0.01		2.320
June	2.14	-0.13	2.007	0.049563	0.25	0.01		2.317
July	2.14	-0.13	2.014	0.049736	0.25	0.01		2.324
August	2.15	-0.13	2.021	0.049909	0.25	0.01		2.331
September	2.15	-0.13	2.025	0.050008	0.25	0.01		2.335
October	2.18	-0.13	2.055	0.050749	0.25	0.01		2.366
November	2.32	-0.13	2.188	0.054033	0.25	0.01		2.502
December	2.46	-0.13	2.333	0.057614	0.25	0.01		2.651

"Look Date" 1-Dec-98

KCI Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.25	0.01	0.15	2.314
February	2.02	-0.13	1.885	0.04655	0.25	0.01	0.15	2.342
March	2.01	-0.13	1.88	0.046427	0.25	0.01	0.15	2.336
April	2.00	-0.13	1.87	0.04618	0.25	0.01	0.15	2.326
May	2.02	-0.13	1.885	0.04655	0.25	0.01	0.15	2.342
June	2.02	-0.13	1.888	0.046624	0.25	0.01	0.15	2.345
July	2.03	-0.13	1.9	0.046921	0.25	0.01	0.15	2.357
August	2.04	-0.13	1.912	0.047217	0.25	0.01	0.15	2.369
September	2.06	-0.13	1.925	0.047538	0.25	0.01	0.15	2.383
October	2.11	-0.13	1.98	0.048896	0.25	0.01	0.15	2.439
November	2.25	-0.13	2.122	0.052403	0.25	0.01	0.15	2.584
December	2.40	-0.13	2.275	0.056181	0.25	0.01	0.15	2.741

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.25	0.01	0.15	2.803
February	2.36	-0.13	2.23	0.055070	0.25	0.01	0.15	2.695
March	2.25	-0.13	2.12	0.052354	0.25	0.01	0.15	2.582
April	2.17	-0.13	2.04	0.050378	0.25	0.01	0.15	2.500
May	2.14	-0.13	2.01	0.049637	0.25	0.01	0.15	2.470
June	2.14	-0.13	2.007	0.049563	0.25	0.01	0.15	2.467
July	2.14	-0.13	2.014	0.049736	0.25	0.01	0.15	2.474
August	2.15	-0.13	2.021	0.049909	0.25	0.01	0.15	2.481
September	2.15	-0.13	2.025	0.050008	0.25	0.01	0.15	2.485
October	2.18	-0.13	2.055	0.050749	0.25	0.01	0.15	2.516
November	2.32	-0.13	2.188	0.054033	0.25	0.01	0.15	2.652
December	2.46	-0.13	2.333	0.057614	0.25	0.01	0.15	2.801

"Look Date" 1-Dec-98

Pleasant Hill Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.05	0.01		1.964
February	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
March	2.01	-0.13	1.88	0.046427	0.05	0.01		1.986
April	2.00	-0.13	1.87	0.04618	0.05	0.01		1.976
May	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
June	2.02	-0.13	1.888	0.046624	0.05	0.01		1.995
July	2.03	-0.13	1.9	0.046921	0.05	0.01		2.007
August	2.04	-0.13	1.912	0.047217	0.05	0.01		2.019
September	2.06	-0.13	1.925	0.047538	0.05	0.01		2.033
October	2.11	-0.13	1.98	0.048896	0.05	0.01		2.089
November	2.25	-0.13	2.122	0.052403	0.05	0.01		2.234
December	2.40	-0.13	2.275	0.056181	0.05	0.01		2.391

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.05	0.01		2.453
February	2.36	-0.13	2.23	0.055070	0.05	0.01		2.345
March	2.25	-0.13	2.12	0.052354	0.05	0.01		2.232
April	2.17	-0.13	2.04	0.050378	0.05	0.01		2.150
May	2.14	-0.13	2.01	0.049637	0.05	0.01		2.120
June	2.14	-0.13	2.007	0.049563	0.05	0.01		2.117
July	2.14	-0.13	2.014	0.049736	0.05	0.01		2.124
August	2.15	-0.13	2.021	0.049909	0.05	0.01		2.131
September	2.15	-0.13	2.025	0.050008	0.05	0.01		2.135
October	2.18	-0.13	2.055	0.050749	0.05	0.01		2.166
November	2.32	-0.13	2.188	0.054033	0.05	0.01		2.302
December	2.46	-0.13	2.333	0.057614	0.05	0.01		2.451

Firm Gas Reservation Cost

Merchant Energy Partners Proposal

	MMBtu Required			
	MW	Heat Rate	Hours/Day	MMBtu/day
April - Sept	500	7,041	24	84,492
Oct - March	200	7,356	24	35,309

	Annual Gas Reservation Cost			
	$/Dthrm/Mo	MMBtu/day	Months	Cost
April - Sept	$ 9.56	84,492	6	$4,846,461
Oct - March	$ 9.56	35,309	6	$2,025,313
Annual Cost				$6,871,774

Houston Industries Proposal

	MMBtu Required			
	MW	Heat Rate	Hours/Day	MMBtu/day
June - Sept	500	10,600	24	127,200
Oct - May	200	10,600	24	50,880

	Annual Gas Reservation Cost			
	$/Dthrm/Mo	MMBtu/day	Months	Cost
June - Sept	$ 9.56	127,200	4	$4,864,128
Oct - May	$ 9.56	50,880	8	$3,891,302
Annual Cost				$8,755,430

CASE 4 Gas Reservation Cost

Gas Usage - 350 MW

	MMBtu Required		
	Max Day	Max Mo.	Avg Mo.
April - Sept	59,500	1,920,000	1,511,000
Oct - March	35,000	1,000,000	910,000

	$/Dthrm/Mo.	
April - Sept	$ 9.56	$ 2,275,280
Oct - March	$ 9.56	$ 2,676,800
Annual Cost		$ 4,952,080

Missouri Power Supply
Bid Comparison
6/1/2001 - 5/31/2005
$x1,000

Without Off System Sales

From> / To>	Jun-01 May-02	Jun-02 May-03	Jun-03 May-04	Jun-04 May-05	NPV Jun-01 May-05
2.5% Gas & Base Mkt					
Merchant Energy Partners	130,139	136,974	145,552	155,784	467,982
Houston Industries	129,268	136,062	146,002	156,282	467,117
1.0% Gas & Low Mkt					
Merchant Energy Partners	128,260	135,234	143,250	152,399	460,435
Houston Industries	127,253	133,600	142,937	152,552	457,966
4.0% Gas & High Mkt					
Merchant Energy Partners	131,883	138,309	147,493	158,865	474,546
Houston Industries	130,628	137,939	148,474	159,645	474,420
2.5% Gas & High Mkt					
Merchant Energy Partners	131,776	137,712	146,524	157,171	471,922
Houston Industries	130,664	137,748	147,939	158,619	473,111
2.5% Gas & Low Mkt					
Merchant Energy Partners	128,367	135,505	143,943	153,526	462,145
Houston Industries	127,291	133,780	143,329	152,976	458,778
2.5% Gas & No Mkt					
Merchant Energy Partners	139,103	141,427	149,751	160,010	486,539
Houston Industries	138,678	146,827	157,098	167,034	501,771
1.0% Gas & No Mkt					
Merchant Energy Partners	138,871	140,652	148,138	157,210	482,321
Houston Industries	138,496	146,133	155,469	164,100	497,558
4.0% Gas & No Mkt					
Merchant Energy Partners	139,332	142,222	151,320	162,818	490,742
Houston Industries	138,862	147,528	158,359	169,102	505,063

With Off System Sales

From> / To>	Jun-01 May-02	Jun-02 May-03	Jun-03 May-04	Jun-04 May-05	NPV Jun-01 May-05
2.5% Gas & Base Mkt					
Merchant Energy Partners	120,645	129,426	139,021	149,469	442,894
Houston Industries	124,080	131,802	142,643	152,936	453,535
1.0% Gas & Low Mkt					
Merchant Energy Partners	121,758	130,149	138,758	147,996	443,252
Houston Industries	123,961	130,875	140,731	150,202	449,103
4.0% Gas & High Mkt					
Merchant Energy Partners	118,753	127,684	138,396	150,342	439,794
Houston Industries	122,910	131,846	143,694	155,201	454,988
2.5% Gas & High Mkt					
Merchant Energy Partners	118,229	126,818	136,691	147,955	435,458
Houston Industries	123,962	130,754	141,296	150,808	449,893
2.5% Gas & Low Mkt					
Merchant Energy Partners	121,984	130,778	139,942	149,787	446,258
Houston Industries	124,051	131,191	141,367	150,981	450,535

Revised: March 1, 1999

Merchant Energy Partners Contract
Annual Ownership and Operating Cost
$x1,000

From>	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-02	May-03	May-04	May-05
Aquila Capacity Payment				
MEP Capacity Payment	17,696	27,660	27,660	27,660
SEC Capacity Payment	6,693			
Union Electric Capacity Payment				
Long Term Peaking Capacity Cost				
Short Term Peaking Capacity Cost			2,837	6,397
Gas Reservation Cost	6,872	6,872	6,872	6,872
Total Fixed Costs	31,261	34,532	37,368	40,929
Without Off System Sales				
MWh $ w/ 2.5% Gas & Base Mkt	98,878	102,442	108,184	114,856
Total Cost	130,139	136,974	145,552	155,784
MWh $ w/ 1.0% Gas & Low Mkt	96,999	100,702	105,882	111,470
Total Cost	128,260	135,234	143,250	152,399
MWh $ w/ 4.0% Gas & High Mkt	100,622	103,777	110,124	117,936
Total Cost	131,883	138,309	147,493	158,865
MWh $ w/ 2.5% Gas & High Mkt	100,516	103,180	109,156	116,243
Total Cost	131,776	137,712	146,524	157,171
MWh $ w/ 2.5% Gas & Low Mkt	97,106	100,973	106,574	112,598
Total Cost	128,367	135,505	143,943	153,526
MWh $ w/ 2.5% Gas & No Mkt	107,842	106,895	112,383	119,082
Total Cost	139,103	141,427	149,751	160,010
MWh $ w/ 1.0% Gas & No Mkt	107,610	106,120	110,770	116,281
Total Cost	138,871	140,652	148,138	157,210
MWh $ w/ 4.0% Gas & No Mkt	108,071	107,691	113,952	121,889
Total Cost	139,332	142,222	151,320	162,818
With Off System Sales				
MWh $ w/ 2.5% Gas & Mkt	89,384	94,895	101,653	108,541
Total Cost	120,645	129,426	139,021	149,469
MWh $ w/ 1.0% Gas & Mkt	90,497	95,617	101,390	107,067
Total Cost	121,758	130,149	138,758	147,996
MWh $ w/ 4.0% Gas & Mkt	87,492	93,153	101,027	109,414
Total Cost	118,753	127,684	138,396	150,342
MWh $ w/ 2.5% Gas & High Mkt	86,968	92,286	99,323	107,026
Total Cost	118,229	126,818	136,691	147,955
MWh $ w/ 2.5% Gas & Low Mkt	90,723	96,246	102,574	108,859
Total Cost	121,984	130,778	139,942	149,787

Revise: March 1, 1999

Houston Industries Contract
Annual Ownership and Operating Cost
$x1,000

From>	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-02	May-03	May-04	May-05
Houston Capacity Payment	23,576	23,576	23,576	23,576
Aquila Capacity Payment				
SEC Capacity Payment				
Union Electric Capacity Payment				
Long Term Peaking Capacity Cost				
Short Term Peaking Capacity Cost			2,837	6,397
Gas Reservation Cost	8,755	8,755	8,755	8,755
Total Fixed Costs	32,331	32,331	35,168	38,728
Without Off System Sales				
MWh $ w/ 2.5% Gas & Base Mkt	96,937	103,731	110,834	117,554
Total Cost	129,268	136,062	146,002	156,282
MWh $ w/ 1.0% Gas & Low Mkt	94,922	101,268	107,769	113,824
Total Cost	127,253	133,600	142,937	152,552
MWh $ w/ 4.0% Gas & Low Mkt	98,296	105,608	113,306	120,917
Total Cost	130,628	137,939	148,474	159,645
MWh $ w/ 2.5% Gas & High Mkt	98,333	105,417	112,771	119,891
Total Cost	130,664	137,748	147,939	158,619
MWh $ w/ 2.5% Gas & Low Mkt	94,960	101,449	108,161	114,248
Total Cost	127,291	133,780	143,329	152,976
MWh $ w/ 2.5% Gas & No Mkt	106,347	114,496	121,930	128,306
Total Cost	138,678	146,827	157,098	167,034
MWh $ w/ 1.0% Gas & No Mkt	106,165	113,801	120,301	125,372
Total Cost	138,496	146,133	155,469	164,100
MWh $ w/ 4.0% Gas & No Mkt	106,530	115,197	123,191	130,374
Total Cost	138,862	147,528	158,359	169,102
With Off System Sales				
MWh $ w/ 2.5% Gas & Base Mkt	91,748	99,470	107,475	114,208
Total Cost	124,080	131,802	142,643	152,936
MWh $ w/ 1.0% Gas & Low Mkt	91,630	98,544	105,563	111,474
Total Cost	123,961	130,875	140,731	150,202
MWh $ w/ 4.0% Gas & Low Mkt	90,579	99,514	108,525	116,473
Total Cost	122,910	131,846	143,694	155,201
MWh $ w/ 2.5% Gas & High Mkt	91,630	98,423	106,128	112,079
Total Cost	123,962	130,754	141,296	150,808
MWh $ w/ 2.5% Gas & Low Mkt	91,720	98,859	106,199	112,253
Total Cost	124,051	131,191	141,367	150,981

CASE 4
Annual Ownership and Operating Cost
$x1,000

					NPV
From>	Jun-01	Jun-02	Jun-03	Jun-04	Jun-01
To>	May-02	May-03	May-04	May-05	May-05
Aquila Capacity Payment					
CP&L Capacity Payment	9,957	10,205	10,454	10,454	
NP Energy Capacity Payment	5,100	5,228	5,358	5,492	
SCEM Capacity Payment	5,576	5,680	5,786	5,897	
SPS Capacity Payment	11,968	12,227	12,227	12,227	
Union Electric Capacity Payment					
Long Term Peaking Capacity Cost				9,479	
Short Term Peaking Capacity Cost		2,214	5,673	582	
Gas Reservation Cost	4,952	4,952	4,952	7,074	
Total Fixed Costs	37,553	40,505	44,451	51,204	
Without Off System Sales					
MWh $ w/Base Gas & Mkt	106,844	112,586	118,605	120,584	
Total Cost	144,397	153,091	163,055	171,788	520,660
MWh $ w/Low Gas & Mkt	105,802	110,791	116,112	116,197	
Total Cost	143,355	151,297	160,562	167,401	512,953
MWh $ w/ High Gas & Mkt	107,848	114,088	120,889	124,837	
Total Cost	145,401	154,593	165,340	176,041	527,817
With Off System Sales					
MWh $ w/Base Gas & Mkt	97,261	103,856	110,773	120,012	
Total Cost	134,814	144,361	155,224	171,216	497,665
MWh $ w/Low Gas & Mkt	99,533	105,103	110,875	115,996	
Total Cost	137,086	145,609	155,326	167,200	497,967
MWh $ w/ High Gas & Mkt	94,034	101,772	109,574	123,976	
Total Cost	131,587	142,277	154,024	175,180	494,851