Carolina Power & Light

COPY

CP&L

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

July 2, 1998

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

Re: CP&L's Proposal Submittal in regard to Utilicorp Energy Groups's RFP

Dear Mr. Harris:

To help meet Missouri Public Service's growing business needs for creative power supply solutions, CP&L is pleased to respond to UtiliCorp Energy Group's May 22, 1998 RFP. Enclosed you will find one original and three copies of our proposal for your consideration.

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 1, 1998. Please let me know if these conditions are not acceptable to Utilicorp Energy Group.

We appreciate the opportunity to provide these proposals. I look forward to hearing from you regarding your evaluation of our proposals.

Yours truly

Karla Haislip
Bulk Power Marketer

enclosures (original and 3 copies)

Proposal Overview

Carolina Power & Light Company (CP&L) is committed to becoming a power supplier for Missouri Public Service. We plan to be your energy supplier of choice by offering a competitive, reliable solution to your power supply needs.

CP&L is an investor owned utility, providing electric power to approximately 1.1 million customers in eastern and western North Carolina and central South Carolina. Founded in 1908 and headquartered in Raleigh, North Carolina, the company has over 10,000 MW of Contributing Resources. Our generating facilities represent a flexible mix of fossil, nuclear and hydroelectric resources.

CP&L is pleased to respond to Missouri Public Service's power supply needs described in its May 22, 1998 request for proposal (RFP) by offering the following proposal, that offers a unique solution for your consideration for a four year term.

We have designed our proposal to provide Missouri Public Service with a power supply option that can be used to shape a solution that best fits Missouri Public Service's needs. A closer look at this proposal will reveal a solution that offers competitive indexed energy pricing.

CP&L is committed to becoming a power supplier for Missouri Public Service. We appreciate the recent opportunity to provide this proposal. Since this is a preliminary introduction to Missouri Public Service, we would value the opportunity to meet and discuss this proposal in further detail as well as your other business needs for the future. We look forward to working with you to finalize the details of this or any other solution that will meet your power supply needs.

CP&L's Proposal

Capacity Components and Term: This proposal is for peaking capacity. Amount equal to 150 MW's. Term of four (4) years beginning June1, 2000 and ending May 31, 2004.

Energy Price: (Pricing at Missouri Public Service's Border) The energy price would be based on a mutually agreed upon gas index at the facility and will include transportation, variable O&M fees, and a heat rate assumption of 12,000 BTU/kWh.

Firmness: This sale is a unit power sale, with a 5% effective forced outage rate. The effective forced outage rate is measured based on peaking availability. Terms and conditions for performance based compensation for exceeding the 5% to be negotiated.

Energy Scheduling: Missouri Public Service provides to CP&L daily, a rolling seven-day estimate of hourly energy usage by 8:00 a.m. The actual energy schedule is fully dispatchable, meaning that Missouri Public Service may make same-day adjustments within reasonable limits with one-hour notice.

Transmission and Ancillary Services Pricing: CP&L will purchase these services necessary and will deliver capacity and energy to Missouri Public Service's border. The price for these services is included in our proposal.

Delivery Point: The delivery point shall be at the interconnection between the facility and Missouri Public Service's transmission system. CP&L reserves the right to provide energy at alternate delivery points into the Missouri Public Service system.

Siting: Missouri Public Service will assist in site location and development. CP&L will have the right to deliver excess capacity and energy to Missouri Public Service's interconnections and will reimburse Missouri Public Service for transmission losses to the interconnections. CP&L has made certain assumptions concerning siting, transmission and fuel supply. Additional information would allow CP&L to refine proposal.

Capacity Pricing

Years	**2000**	**2001**	**2002**	**2003**	**2004**
Demand Charges ($/MW-month)	$4690	$4810	$4930	$5050	$5180

CP&L

September 4, 1998

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

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

LS Power

PROPOSAL FOR POWER SUPPLY
FROM LS POWER, LLC
TO UTILICORP ENERGY GROUP
ON BEHALF OF MISSOURI PUBLIC SERVICE
JULY 2, 1998

EXECUTIVE SUMMARY

LS Power, LLC and its affiliates ("LS Power") is a leader in the development of greenfield generation facilities serving the United States market. Within the past several years LS Power completed construction of three projects comprising approximately 700 megawatts and has commenced construction on another two projects representing 716 megawatts of capacity. Additionally, LS Power has another 800 megawatts committed pursuant to power purchase agreements, with numerous other projects under development. Given the transition in the electric utility industry, this accomplishment serves as a testament to LS Power's commitment to the United States market and its ability to structure highly competitive, flexible and innovative business arrangements with its customers.

Of particular relevance to this proposal is the long standing working relationship that has been established between UtiliCorp and LS Power. For example, Aquila Energy Marketing Corporation is under a long term contract to supply gas to the Whitewater, Wisconsin and Cottage Grove, Minnesota Projects developed by LS Power. Aquila will also be supplying gas to the Mustang Project located in Denver City, Texas. Most recently, Aquila Power Corporation and UtiliCorp United, Inc. entered into a power purchase agreement with LSP Energy Limited Partnership for supply from our Batesville, Mississippi Project.

With this proposal, LS Power, LLC ("LSP") is offering to provide Missouri Public Service ("MPS") the output of either one or two (at MPS's choice) combined cycle trains under the terms of a tolling arrangement. The nominal output of each train will be 270 MW. The units will be located at a site within MSP's service territory, with the specific location to be determined with input from MPS. Based upon execution of a letter of intent for a power purchase agreement by August 1, 1998 and execution of a power purchase agreement by September 1, 1998, the delivery start date will be June 1, 2001. LSP will be responsible for developing, financing, constructing, operating and maintaining the project.

LSP views this proposal as a starting point to an interactive process between MPS and LSP to refine the specifics of a power purchase arrangement that satisfies the respective objectives of each party. During the evaluation process, LSP strongly encourages MPS to provide feedback to LSP to facilitate such an interactive process, and in turn, LSP commits to work with MPS to structure an arrangement that is mutually beneficial.

CONTRACT QUANTITY

The Contract Quantity will be the sum of the Standard Capacity and the Supplemental Capacity. "Standard Capacity" is the maximum output of the unit without the use of power augmentation measures. "Supplemental Capacity" is the capacity over and above the Standard Capacity which is produced with the use of power augmentation measures. LSP estimates the Contract Quantity for each unit to be approximately 270 MW, with the Supplemental Capacity comprising approximately 6 to 12% of this amount. LSP will perform a test each year to demonstrate the capability of each unit.

DELIVERY START DATE AND TERM

The delivery start date will be June 1, 2001 and the term will be ten years from this date.

DELIVERY POINT

MPS's high voltage transmission system.

FUEL ARRANGEMENTS

MPS will be responsible for arranging, procuring, and delivering to the project all fuel required by LSP to deliver energy from each unit to MPS, including, but not limited to, arrangements for fuel supply, fuel transport, nominations and balancing. LSP will be responsible for installing the necessary pipeline facilities to provide the project with access to fuel deliveries.

SCHEDULING AND DISPATCH

The project will be fully dispatchable within the design limits and within MPS's gas supply/transport arrangements. The design limits will include but not be limited to the following:

(i) minimum load equal to 70% of the Contract Quantity;

(ii) the capability to ramp from minimum load up to the Standard Capacity at an average rate no less than 5 MW per minute;

(iii) one start per day for each unit;

(iv) maximum time from MPS's notice of start up to minimum load in accordance with manufacturers' recommendations.

CAPACITY PAYMENT

MPS will pay LSP a capacity payment each month of the contract term commencing on the delivery start date, calculated as follows:

$$CP = CR_N \times CQ \times AAF\text{, where}$$

CP = the Capacity Payment expressed in dollars for the month,

CR_N = is the Capacity Rate expressed in dollars per kilowatt per month applicable for each contract year "N", equal to $5.50 per kW per month for the first year of project operation, with escalation for subsequent years of project operation at the rate of 2% per year,

CQ = the Contract Quantity of the unit(s), expressed in kW,

AAF = the Availability Adjustment Factor for the month as defined below.

The "Availability Adjustment Factor" will be computed on a twelve month rolling average basis as follows:

AAF = 1 for the first twelve months of project operation, and thereafter

$$AAF = AH_{12}/(0.97 \times PH_{12})\text{, where}$$

AH_{12} = the number of hours during the previous twelve month period that the project was available to deliver the Contract Quantity or delivered energy pursuant to MPS's dispatch orders from an alternate source, prorated for partial outages or derates, and

PH_{12} = the total number of hours during the previous twelve month period less outages caused by force majeure events and scheduled outages approved by MPS, prorated for partial outages or derates.

ENERGY PAYMENT

MPS will pay LSP an amount equal to $1.00 per MWH as of January 1, 1998 escalating annually thereafter at the rate of change in the Gross Domestic Product Implicit Price Deflator for each MWH of energy delivered by LSP to MPS.

MPS will pay for all fuel required to deliver energy scheduled by MPS. A tracking account will be maintained to track the actual amount of fuel required to produce the energy scheduled by MPS and delivered by LSP and the actual delivered price of fuel for such day. If the actual amount of fuel required to produce such energy varies from the amount of fuel required to produce such energy based on the Guaranteed Heat Rate as adjusted for part loading and/or power augmentation, then a balance will accrue in the tracking account for such day. If the actual amount of fuel required to produce such energy on such day is greater than the required amount based on the Guaranteed Heat Rate adjusted for part loading and/or power augmentation, then a positive amount equal to the differential fuel required, expressed in MMBtu, times the delivered cost of fuel, expressed in dollars per MMBtu, for such day will accrue to the tracking account for such day. If the actual amount of fuel required to produce such energy on such day is less than the amount required based on the Guaranteed Heat Rate adjusted for part loading and/or power augmentation, then a negative amount equal to the differential fuel, expressed in MMBtu, times the delivered cost of fuel, expressed in dollars per MMBtu, for such day will accrue to the tracking account for such day. At the end of each month, the tracking account will be cleared and if the tracking account balance is positive, LSP will pay MPS such amount, whereas if the tracking account balance is negative, MPS will pay LSP such amount.

START UP PAYMENT

In the event the number of starts for a unit exceeds 150 per contract year, MPS will pay to LSP a start up payment equal to the start up rate times the number of starts over 150. The start up rate will be $5,000 per start up as of January 1, 1998 escalating annually thereafter at the rate of change in the Gross Domestic Product Implicit Price Deflator.

MPS will also pay for fuel required during start up to reach minimum load. Energy produced during start up will be delivered to MPS at the delivery point.

GUARANTEED HEAT RATE

The "Guaranteed Heat Rate" will be 7.500 MMBtu/MWH (HHV) for the full load Standard Capacity from each unit. If a unit is loaded less than the full load Standard Capacity, the Guaranteed Heat Rate will be adjusted in accordance with manufacturer's adjustment factors to reflect part loading. The Guaranteed Heat Rate for Supplemental Capacity from each unit will be 10.500 MMBtu /MWH (HHV).

BUYOUT OPTION

MPS will have the option to purchase the unit(s) at the end of the contract term by providing notice to LSP, no later than twenty four months prior to the end of the term, of its intention to exercise its purchase option. The buyout price to purchase the unit(s) will be determined as the greater of fair market value or the amount necessary to repay all senior and junior debt and provide the same net present value return to the equity investors as contemplated at the time of financial closing.

COMPLETION GUARANTEES AND SECURITY

In the event that commercial operation has not been achieved by the delivery start date, and to the extent MPS would have otherwise requested deliveries from LSP, LSP at its option will either (i) provide replacement power to MPS, (ii) pay MPS for its reasonable costs associated with securing replacement power, or (iii) pay delay damages payments. LSP will provide certain forms of security to MPS to guarantee that the project will be completed on time and will operate as promised. These include a milestone completion schedule and completion security. Specific details of these securities need to be further discussed with MPS.

SCHEDULED MAINTENANCE

Scheduled maintenance will be performed in accordance with manufacturer's recommendations and prudent practices. The number of days of scheduled maintenance outages per year will be a function of the type of maintenance that is required, which, in turn, will be a function of the number of starts and the number of operating hours for each unit. The total duration of maintenance outages will be no more than 20 days per year except when a major maintenance outage is required, in which case the total maintenance outage days will be no more than 35 days per year. For partial outages, the number of maintenance days will be prorated accordingly. LSP will coordinate scheduled maintenance outages with MPS.

LS POWER
QUALIFICATIONS AND EXPERIENCE

LS Power, LLC and its affiliates ("LS Power") is a leader in the development of greenfield generation facilities serving the United States market. Within the past several years LS Power completed construction of three projects comprising approximately 700 megawatts and has commenced construction on another two projects representing 716 megawatts of capacity. Additionally, LS Power has another 800 megawatts committed pursuant to power purchase agreements, with numerous other projects under development. Given the transition in the electric utility industry, this accomplishment serves as a testament to LS Power's commitment to the United States market and its ability to structure highly competitive, flexible and innovative business arrangements with its customers.

One key to achieving this success is the nature of the relationship that LS Power establishes with its customers. LS Power considers its customers as partners in the projects it develops, and in some cases, actually formalizes this partnership. The Borger and Mustang Projects illustrate this business philosophy.

The Borger Project is being developed by the partnership of LS Power and Quixx Corporation, a subsidiary of New Century Energies. This 216 megawatt facility will sell electricity under a long term power purchase agreement to Southwestern Public Service Company (also a subsidiary of New Century Energies) and steam to the Phillips Petroleum Refinery located near Borger, Texas. The project started construction in October, 1997 and full commercial operation is scheduled for early 1999.

The Mustang Project is also being developed by the partnership of LS Power and Quixx. This 500 megawatt combined cycle facility is located in Denver City, Texas. Once operational, fifty percent of the project will be sold to Golden Spread Electric Cooperative and the balance of the output from the LS Power/Quixx share of the project will be sold under a long term power purchase agreement with Golden Spread. The project commenced construction in December, 1997 and will be completed in two phases, simple cycle in spring of 1999 and combined cycle in late 1999.

LS Power structures business arrangements that provide attractive economics, equitable risk sharing and other features that may include our customer's participation in the selection of project design and site, joint development of the fuel supply strategy, review of operation and maintenance procedures, flexibility in commercial operation/construction schedules and ownership participation options. An example of this is LS Power's Batesville Project which will provide 800 MW of capacity and energy via tolling arrangements with two power purchasers. This project is located in Batesville, Mississippi on the border of the Tennessee Valley Authority and Entergy Systems.

LS Power has been recognized by the industry as a leader in power project development. The 250 megawatt Whitewater, Wisconsin and Cottage Grove, Minnesota

Projects developed by LS Power were embraced not only by our utility customers, but also by the financial markets, state regulators, environmental agencies and local communities. For example, these projects received *Project Finance Monthly's* (a publication of Information Forecast, Inc.) Most Significant Domestic Project Award for 1995. The $332 million of public debt for our Cottage Grove and Whitewater Projects received a rating of Baa2 by Moody's and BBB by Standard and Poor's. This is a rating higher than for any other independent power project financing.

Another key to LS Power's success is its in-house expertise in the areas of cycle design, permitting and regulatory affairs, gas supply and transportation, financing, public relations, and in particular, understanding of the electric utility industry. One cornerstone of our resource base is that several of LS Power's key personnel have spent decades working in the electric utility industry in the areas of planning, transmission/substation design, power plant design, power plant operations and utility management. This experience empowers us to relate well with our customers, appreciate their needs and offer solutions that are responsive to those needs.

LS Power is also strong financially, serving as the general partner of Granite Power Partners II, L.P., a limited partnership which provides development stage funding for the projects developed by LS Power. Financial investors, including the Chase Manhattan Capital Corporation, are limited partners of Granite. Chase is one of the largest financial institutions in the world and has financed billions of dollars worth of independent power projects. LS Power is a privately held company and as such does not disclose financial information. An annual report for Chase is available upon request.

LS POWER
PROJECT DESCRIPTIONS

COTTAGE GROVE COGENERATION PROJECT

The Cottage Grove Project is located in Cottage Grove, Minnesota. The project is a fully dispatchable, intermediate load, combined-cycle natural gas-fired (with fuel oil backup) combustion turbine cogeneration facility designed to generate approximately 245 MW of electrical power and approximately 200,000 pounds per hour of steam. Electrical energy is being sold to Northern States Power Company (NSP) under a 30 year agreement which was negotiated pursuant to a competitive selection process administered by NSP and approved by the Minnesota Public Utilities Commission. The facility also produces steam for sale to the 3M Cottage Grove Plant, replacing steam previously produced by coal-fired boilers. The project achieved commercial operation in October, 1997.

The Cottage Grove project was selected in June, 1993 by NSP to provide intermediate capacity and associated energy. The selection was made over strong competition from a variety of different sources (Independent Power Producers, Utilities, and the NSP-sponsored Wheaton Project). The Cottage Grove Project was evaluated to have the lowest cost to NSP and its ratepayers along with many socio-economic benefits to the region.

The Cottage Grove Project has contracted with two domestic suppliers (Natural Gas Clearinghouse and Aquila Energy Marketing Company) under an indexed pricing arrangement. These contracts have been structured with several levels of supply to match nomination commitments on a monthly, daily and no-notice basis. Gas transportation has been arranged under a series of long term contracts with Northern Natural Pipeline Company and Peoples Natural Gas Company (the LDC) that involve capacity release, and a combination of storage, firm and interruptible transportation that assures reliable, cost effective delivery.

Westinghouse Electric Corporation provided turnkey engineering, procurement and construction services for the project. Westinghouse Operating Services Company is currently providing operation and maintenance services.

The permits and approvals for the project included a Certificate of Need, Certificate of Site Compatibility, Air Permit and NPDES Permit. The entire permitting process was quite expeditious compared with previous power generation projects in the state, requiring a total of nine months.

This project was developed by LS Power and was financed jointly with the Whitewater Cogeneration Project via LS Power Funding Corporation. The Senior Secured 144A Bonds were arranged by Chase Securities, Inc. and Morgan Stanley & Company, Inc. S&P's rating of BBB is higher than for any other independent power project. Granite Power Partners, L.P. recently sold its majority ownership interest in this project.

WHITEWATER COGENERATION PROJECT

The Whitewater Cogeneration Facility is located in Whitewater, Wisconsin. The project is a fully dispatchable, intermediate load, combined-cycle natural gas-fired (with fuel oil backup) combustion turbine cogeneration facility designed to generate approximately 245 MW of electrical capacity and approximately 200,000 pounds per hour of steam. Electrical energy is being sold to the Wisconsin Electric Power Company (WEPCO) under a 25 year agreement which was negotiated pursuant to a competitive bidding process administered by the Public Service Commission of Wisconsin. The facility provides steam to several steam customers including the University of Wisconsin at Whitewater. The project achieved commercial operation in September, 1997.

The project was proposed in June, 1993 to WEPCO as an alternative to its own self-generation plans (the Kimberly Project). In November, 1993, the PSCW selected the Whitewater Project over numerous other bidders including the Kimberly Project. The evaluation results concluded the LS Power Project offered the lowest cost to WEPCO and its ratepayers.

The Whitewater Project has contracted with two domestic suppliers under an indexed pricing arrangement. Gas transportation has been arranged under a series of long term contracts with Northern Natural Pipeline Company, Wisconsin Natural Gas Company (the LDC) and another Wisconsin utility. These transportation agreements involve a reverse capacity release, and a combination of storage, firm and interruptible transportation that assures reliable, cost effective delivery.

The permits and approvals for the project included a Certificate of Public Convenience and Necessity, Air Permit and WPDES Permit. The entire permitting process was quite expeditious compared with previous power generation projects in the state, requiring a total of thirteen months.

Ownership, financing, turnkey construction, and O&M arrangements for the Whitewater Project are similar to those for the Cottage Grove Project.

LOCKPORT ENERGY ASSOCIATES, L.P.

LS Power, under contract with the CU Energy Partnership, developed and managed the financing and construction of this 200 MW, $220 million combined cycle gas/oil-fired cogeneration project in Lockport, New York. This project sells power to New York State Electric & Gas Company under a power purchase agreement. The project also supplies up to 300,000 pounds per hour of steam and up to 24 MW of electricity to the Harrison Radiator Division of General Motors under a 15-year contract. The project entered commercial operation in December, 1992.

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.

Merchant Energy Partners

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

November 30, 1998

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

AQUILA ENERGY

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.

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3 8 40
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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

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.

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.

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

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.

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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. <u>Emission Allowances</u>. 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. <u>Part-load heat rate curves</u> -- 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. <u>Minimum load requirements</u> -- 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

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	[illegible]	7604	7886	← 1% Degrade			
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						← 1% Degrade			
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.

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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

New Century Enegies

NEW CENTURY
ENERGIES℠

PUBLIC SERVICE
COMPANY OF COLORADO℠

SOUTHWESTERN
PUBLIC SERVICE COMPANY℠

CHEYENNE LIGHT
FUEL & POWER℠

PO Box 1261
Amarillo, Texas 79170-0001
Telephone 806.378.2121

July 3, 1998

UtiliCorp Energy Group
Attn: Mr. Frank A. Debacker
107500 East 350 Highway
Kansas City, Missouri 64138

RE: Request for Proposals dated May 22, 1998.
Purchase of Resource Specific Capacity and Energy for the period June 1, 2000 through May 31, 2004.

In response to UtiliCorp Energy Group's ("UEG") request for proposals, Southwestern Public Service Company ("SPS") will agree to sell the following resource specific capacity and energy to UEG's operating division Missouri Public Service ("MPS") under the terms presented in the following options, pursuant to and in accordance with SPS' Market Based Tariff. Terms used, but not defined herein shall have the meaning ascribed to them in the definitive agreement. Information contained in this response is to be used solely by UEG for evaluation purposes only and contains privileged and confidential information not to be shared with third parties without prior written consent of SPS.

OPTION A - PARTIAL REQUIRMENT POWER SERVICE, WITH PEAKING POWER SERVICE

The term "Partial Requirements Power Service, with Peaking Power Service" shall mean that quantity of firm electric power and associated energy that SPS will make continuously available to UEG and which will meet the capacity and energy needs of UEG.

Contract Period: The months of June 1, 2001 through May 31, 2004.

Partial Requirements Capacity Amounts: As per the following Table 1:

TABLE 1	
Period	**Capacity**
June 1, 2000 - May 31, 2001	25 or 75 MW
June 1, 2001 - May 31, 2002	50 or 100 MW
June 1, 2002 - May 31, 2003	50 or 100 MW
June 1, 2003 - May 31, 2004	50 or 100 MW

Peaking Power Capacity Amounts: As per the following Table 2 (and to be taken in addition to the Partial Requirements Capacity amounts):

TABLE 2	
Period	**Capacity**
June 1, 2000 - September 30, 2000	25 MW

Billing and Scheduling Charge: $320.00 per month.

Partial Requirements Capacity Charge: The price of the Partial Requirements Power Service Capacity is as shown in the Table 3:

TABLE 3	
Period	**Capacity**
June 1, 2000 - May 31, 2001	$ 5,200/MW - Month
June 1, 2001 - May 31, 2002	$ 5,200/MW - Month
June 1, 2002 - May 31, 2003	$ 5,400/MW - Month
June 1, 2003 - May 31, 2004	$ 5,400/MW - Month

Peaking Power Capacity Charge: The price of the Peaking Power Capacity is as shown in Table 4:

TABLE 4	
Period	**Capacity Charge**
June 1, 2000 - September 30, 2000	$ 9,000/MW - Month

Partial Requirements Energy Price: The price of energy delivered to UEG shall be $1.00/MWh plus the Wholesale Fuel Cost Adjustment Factor.

Wholesale Fuel Cost Adjustment Factor: Attachment 1 is a copy of SPS' Wholesale Fuel Cost Adjustment (FCA) Clause currently in effect. Table 5 shows an estimate of the anticipated Wholesale FCA for the calendar years shown.

TABLE 5	
Year	**Projected Wholesale FCA Factor ($/MWh)**
2000	19.00
2001	18.17
2002	17.79
2003	15.90
2004	16.38

Unless another method is mutually agreed upon, SPS will notify UEG of the estimated Wholesale FCA Factor prior to the upcoming month. Any deviations from the actual to the estimated Wholesale FCA Factor shall be accounted for in the month immediately following.

Peaking Power Energy Price: The energy price for all energy produced for UEG from Peaking Power Service shall be $4.00/MWh plus either of the following of the pricing methods:

1. The price of natural gas multiplied by 1.05 (New Mexico Gross Receipts Tax) and multiplied by the assigned heat rate of 11.5 MMBtu/MWh. The price of natural gas shall be the greater of the Gas Daily Index plus $0.30 or Gas Daily Index times 1.15. Where the Gas Daily Index is the price stated in dollars per MMBtu for the daily midpoint of Northern (Mids 1 - 6) as published on the day of delivery in Pasha Publication's Gas Daily under the table titled "Daily Price Survey".
2. UEG can be responsible for the procurement and delivery of all natural gas to a suitable delivery point for all the electric energy requested by UEG.

Point of Supply: The Points of Supply shall be the generator bus or busses from any of SPS generation resources. UEG shall be responsible for reimbursing SPS for the cost of firm transmission and ancillary services through SPS from any of SPS' generation resources to the MPS transmission system, including losses, as outlined in the section entitled "Transmission and Ancillary Services."

Availability: In the case of Partial Requirements Power Service, with Peaking Power Service, SPS defines availability as the amount of available capacity from SPS generation resources designated to deliver energy to its firm customers. As long as SPS has generation available to its firm customers, SPS will supply the energy.

Partial Requirements Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am for all energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule Partial Requirements Energy on an emergency basis (i.e. only two hours notice), SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall be 10 MW for one hour. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

Peaking Power Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am for Peaking Power energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule this on an emergency basis (i.e. only two hours notice) SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall be 25 MW for eight hours. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

Buy-Out Provision: Should UEG wish to remove itself from its Partial Requirements capacity purchase obligations for the Contract Years beginning June 1, 2002 through May 31, 2004, UEG may do so under the schedule shown in Table 6:

TABLE 6			
Contract Year	**Notice of Buy -Out Given During:**	**Amount of Capacity to Buy-Out**	**Cost per MW of Capacity Buy-Out**
June 2002 through May 2003	10/1/2001 - 12/31/2001	100 MW	$ 2,700/MW – Month
June 2002 through May 2003	1/1/2002 - 2/28/2002	100 MW	$ 4,050/MW – Month
June 2003 through May 2004	10/1/2002 - 12/31/2002	100 MW	$ 2,700/MW – Month
June 2003 through May 2004	1/1/2003 - 2/28/2003	100 MW	$ 4,050/MW – Month

Other General Buy-Out Provisions:

- UEG may buy-out all, or portions thereof, of their capacity obligations in 50 MW increments, during the Contract Years for June 2002 - May 2003 and June 2003 - May 2004. After February 28, 2002, UEG cannot remove itself from the obligation to purchase the capacity for June 2002 - May 2003, but will still have the ability to buy-out of its obligation to purchase capacity for the Contract Year June 2003 - May 2004, for the amount shown in Table 6.
- UEG shall reimburse SPS for long-term transmission and ancillary services purchased to meet delivery obligations to MPS.
- SPS shall not be liable for any 'stranded costs' of UEG relating to fuel acquisitions or fuel transportation arrangements should UEG execute any buy-out provision.

OPTION B - INTERRUPTIBLE POWER SERVICE

The term "Interruptible Power Service" shall mean that quantity of electric power and associated energy that SPS will make continuously available to UEG, except at times of system contingencies as determined by SPS at its discretion at which time it may be curtailed.

Contract Period: The period from June 1 2000, through May 31, 2004.

Capacity Amounts: Up to the amounts shown in Table 7, in 50 MW increments and a minimum of 50 MW for all Contract Years:

Table 7

Contract Year	Months & Capacity Amount	Months & Capacity Amount
6/1/2000 – 5/31/2001	June – September: 100 MW	October – May: 75 MW
6/1/2001 – 5/31/2002	June – September: 100 MW	October – May: 150 MW
6/1/2002 – 5/31/2003	June – September: 100 MW	October – May: 150 MW
6/1/2003 – 5/31/2004	June – September: 100 MW	October – May: 150 MW

In the three contract years, from June 1, 2001 through May 31, 2004, UEG may only purchase capacity during the months of October through May in amounts no less than what was purchased for June through September of the same Contract Year.

Billing and Scheduling Charge: $320.00 per month.

Interruptible Power Capacity Charge: The price of the Interruptible Power Capacity is as shown in the Table 8:

TABLE 8	
Period	**Capacity Charge**
June 1, 2000 – May 31, 2001	$ 4,200/MW - Month
June 1, 2001 – May 30, 2002	$ 4,300/MW - Month
June 1, 2002 – May 31, 2003	$ 4,400/MW - Month
June 1, 2003 – May 31, 2004	$ 4,500/MW - Month

Interruptible Energy Price: The price of energy delivered to UEG shall be $2.50/MWh plus the Wholesale FCA Factor (refer to Attachment 1 and Table 5 in Option A for and estimate of the Wholesale FCA Factor).

Point of Supply: The Points of Supply shall be the generator bus or busses from any of SPS generation resources. UEG shall be responsible for reimbursing SPS for the cost of firm transmission and ancillary services through SPS from any of SPS' generation resources to the MPS transmission system, including losses, as outlined in the section entitled "Transmission and Ancillary Services."

Availability: SPS defines Availability, for any Billing Period, as the ratio expressed as a percentage of the total amount of the electrical energy SPS can continuously deliver the rated amount of contract capacity divided by the product of the Contract Capacity and the number of hours in the Billing Period. The Billing Period is hereby defined as the Hours Ending ("HE") 0100 on the first day for a given calendar month through HE 2400 on the last day of the given calendar month. In this case the, SPS guarantees an availability of 95% for Billing Periods during the Contract Period for all months June through September and an availability of 97% for Billing Periods during the Contract Period for all months October through May.

For example, in the case of Interruptible Capacity during the month of June 2000, SPS should be capable of producing up to 72,000 MWhs (100 MW x 720 hours) during the Billing Period. Therefore, SPS will fail to meet its 95% availability criteria if SPS is unable to deliver more than 3,600 MWhs (0.05 x 72,000 MWhs) to UEG, if and only if UEG has scheduled such energy for delivery from SPS during Billing Period during June 2000.

Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am for all energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule Interruptible Energy on an emergency basis (i.e. only two hours notice), SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall 10 MW for one hour. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

Buy-Out Provision: Should UEG wish to remove itself from its Interruptible Power capacity purchase obligations for the Contract Years beginning June 1, 2002 through May 31, 2004, UEG may do so under the schedule shown in Table 9:

TABLE 9			
Contract Year	**Notice of Buy -Out Given During:**	**Amount of Capacity to Buy-Out**	**Cost per MW of Capacity Buy-Out**
June 2002 through May 2003	10/1/2001 - 12/31/2001	Up to 150 MW	$880/MW – Month
June 2002 through May 2003	1/1/2002 - 2/28/2002	Up to 150 MW	$1,760/MW – Month
June 2003 through May 2004	10/1/2002 - 12/31/2002	Up to 150 MW	$900/MW – Month
June 2003 through May 2004	1/1/2003 - 2/28/2003	Up to 150 MW	$1,800/MW – Month

Other General Buy-Out Provisions:

- UEG may buy-out all, or portions thereof, of their capacity obligations in 50 MW increments, during the Contract Years for June 2002 - May 2003 and June 2003 - May 2004, provided that in any remaining blocks of capacity UEG continues to purchase during the months of October through May, are purchased in amounts no less than what will be purchased for June through September of the same Contract Year.

After February 28, 2002, UEG cannot remove itself from the obligation to purchase the capacity for June 2002 - May 2003, but will still have the ability to buy-out of its obligation to purchase capacity for the Contract Year June 2003 - May 2004, for the amount shown in Table 9.

- UEG shall reimburse SPS for long-term transmission and ancillary services purchased to meet delivery obligations to MPS.
- SPS shall not be liable for any 'stranded costs' of UEG relating to fuel acquisitions or fuel transportation arrangements should UEG execute any buy-out provision.

TRANSMISSION AND ANCILLARY SERVICES

As per Section C and G of the UEG's request for proposals, SPS will provide for transmission and ancillary services from the Point of Supply to the Point of Delivery under separate agreements, under which UEG shall reimburse SPS the total costs incurred for these services. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction. To help UEG in the evaluation of this proposal, the costs from the various transmission and ancillary service providers and the SPP Regional Transmission Tariff as shown in Attachment 2. SPS will work closely with UEG to ensure the most reliable and economical transmission and ancillary services are acquired for this agreement.

UEG may request SPS deliver energy, under terms of this agreement, to UtiliCorp's West Plains Energy – Kansas Division (WPEKS), subject to the availability of SPS' transmission and regulatory conditions that may impact both MPS and WPEKS. SPS would also like to point out that flows from SPS to MPS, scheduled through WPEKS, will have the net affect of displacing generation and energy from the Jeffrey Energy Center in Central Kansas, of which MPS currently derives a portion of its total capacity resources.

The cost of the energy from the options listed above does not take into account the effect of the losses incurred when transmitting electrical energy across various transmission systems. UEG, at its choosing, can either 1) take receipt of the energy at the Point of Delivery minus an amount of energy equal to the losses incurred to delivery the energy, 2) purchase the losses, through SPS, from either the SPP or other regional transmission providers, or 3) purchase the losses directly from the SPP or other regional transmission providers.

SPS understands that these terms and conditions are subject to review and approval by UEG as stated in the request for proposal. This proposal is valid through August 31, 1998 and is subject to prior sale and the completion of a definitive agreement, management approvals, and the availability of transmission and ancillary services from SPS, the Southwest Power Pool, and any other transmission provider from which transmission services are necessary in order to deliver firm capacity and energy to UEG.

If you have any questions, comments or need additional information, please feel free to call me at 806-378-2376.

Sincerely,

Mike Martin
Regional Power Sales Representative

cc: Todd Hegwer

ATTACHMENT 1

Southwestern *PUBLIC SERVICE* Company

COMMISSION	SCHEDULE	SHEET	RATE SCHEDULE NUMBER
~~FERC~~			

WHOLESALE FUEL COST ADJUSTMENT CLAUSE

TARIFF NUMBER	~~7105.1~~
CANCELLING	~~7105.0~~

1. The charges for actual wholesale service rendered during the current billing period shall be increased or decreased by an adjustment amount, per kilowatt-hour of sales (to the nearest 0.0001¢), equal to the difference between the estimated fuel cost (eF) per kilowatt-hour of estimated sales (eS) in the current, or billing, period (m) and the base period (b), as adjusted to allow for wholesale losses (L), with the total charges adjusted by a dollar amount to correct for prior wholesale over or under collections:

$$\text{Adjustment Factor} = \left[\frac{eFm}{eSm} - \frac{eFb}{eSb}\right] (L)$$

2. Fuel costs (F) shall be the cost of:

   (i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

   (ii) Plus, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. Included therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.

   (iii) Plus, the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such charges), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as:

      (1) charges incurred for economy energy purchases and

      (2) charges incurred as a result of scheduled outages,

      all such kinds of energy being purchased by the Company to substitute for its own higher cost energy.

Effective Date January 1, 1990 Approved Bill D. Helton

TAR62

(iv) Less, the cost of fossil and nuclear fuel recovered through inter-system sales, including the fuel costs recovered from economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be equated to:

(i) the sum, measured at the bus-bar or interconnection point, of (1) generation, (2) purchases, and (3) interchange-in,

(ii) less (1) inter-system sales, as referred to in 2.(iv) above, and (2) inter-system losses.

4. "L", the adjustment for wholesale losses, determined at the wholesale delivery points, shall be equal to:

$$1.039 = \frac{1}{1 - 3.754\%}$$

5. The current month adjustment for prior wholesale over or under collections shall be calculated as:

(i) the first prior month's (p) actual fuel costs (aF) divided by actual sales (aS),

(ii) minus that month's (p) estimated fuel costs (eF) divided by estimated sales (eS),

(iii) times the wholesale loss adjustment (L),

(iv) times actual wholesale sales (W) in that month (p) for each customer.

$$\text{Adjustment Amount} = \left[\frac{aFp}{aSp} - \frac{eFp}{eSp}\right] (L)\ (Wp)$$

The adjustment amount shall be debited or credited to the current month's billing.

6. (i) The fuel cost adjustment factor calculation shall not include:

(1) the net energy cost of electric energy purchased from Celanese Corporation and,

(2) the kilowatthours generated at the Celanese Corporation chemical plant, not to exceed the amount of electric energy consumed at that plant.

(ii) The fuel cost adjustment factor calculation shall include both the net energy cost of energy purchased from Celanese, and the kWh generated at its plant, for any amount of energy which does exceed the amount consumed at that plant.

ATTACHMENT 2

Transmission and Ancillary Service Charges: The following table outlines the various charges to deliver the capacity and energy to MPS:

Southwestern Public Service	**Demand Charge**	**Energy Charge**
Firm Transmission	$1,358/MW - month	
Scheduling	$28.9/MW - month	
VAR/Voltage Support	$34.6/MW - month	
Losses	See Note 1.	
West Plains Energy – KS (WPEKS)		
Firm Transmission	$1,083/MW - month	
Scheduling	$54.0/MW - month	
VAR/Voltage Support		$0.190/MWh
Losses	See Note 2.	
Western Resources (WRI)		
Firm Transmission	$1,300/MW - month	
Scheduling		$0.1561/MWh
VAR/Voltage Support	$39.47/MW - month	
Losses	See Note 3.	
Central and Southwest (CSW)		
Firm Transmission	$1,100/MW - month	
Scheduling	See Note 4.	
VAR/Voltage Support	See Note 5.	
Losses	See Note 6.	

Note 1: Losses for SPS system are as follows:
Demand Related Loss Factor is 3.6984%
Energy Related Loss Factor is 4.4863%

Note 2: Losses for WPEKS are 6.0% in the months May - October, 5.0% in the months November - April.

Note 3: Losses will be as follows (from WRI's OA Tariff):

Real Power Losses shall be calculated by multiplying the capacity and energy received at the Receipt Points by the applicable Real Power Loss factors stated below for the voltage at the Point of Receipt or Point of Delivery, whichever is lower. For deliveries to a Control Area interface, the Real Power Loss factor shall be the average of the applicable factors stated below for each interconnection within the interface.

Voltage	Meter Location	Transmission Losses
230-345 KV	High Side	0.87%
	Low Side	1.62%
115-161 KV	High Side	1.62%
	Low Side	3.04%
34.5-69 KV	High Side	3.04%
	Low Side	4.43%

Where:

"High Side" refers to a line tap meter location at the stated voltage or, in the case of a delivery point requiring the use of a step-down transformer, to the high voltage side of such transformer.

"Low Side" refers to a meter within a substation and located on the low voltage side of a step-down transformer.

"Bus" refers to a meter within a substation and located on the substation bus at the stated voltage.

"Circuit" refers to a line tap meter location at the stated voltage.

Note 4: CSW charges $66/transaction/day for each schedule across CSW's transmission system within the SPP.

Note 5: As per CSW's OA Tariff, "Reactive Supply and Voltage Control from Generation Sources Service will be provided directly by PSO/SWEPCO as the Control Area operator. The Transmission Customer must purchase this service from PSO/SWEPCO. PSO/SWEPCO will not impose a separate charge for Reactive Supply and Voltage Control from Generation Sources Service."

Note 6: The Loss Factors on the CSW's alternating current facilities in the SPP are as follows:

Capacity loss factor: 3.3%
Capacity loss factor: 1.7%

The Transmission and Ancillary Service Charges are based on the SPS', WRI's, CSW's and WPEKS' open access tariffs. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction.

Based on the firm transmission charges from SPS' generating resources, the most cost effective path to MPS is from SPS through WPEKS and WRI, although an alternate path from SPS through CSW and WRI is available. Actual paths and charges will depend upon the various Available Transmission Capacity (ATC) between the above transmission providers at the time transmission is requested and/or obtained.

ATTACHMENT 2

SPS - MPS
FIRM

MW-Mile($)					
Hourly Off-Peak	Hourly On-Peak	Daily	Weekly	Monthly	Last Updated
4.107	8.648	138.374	691.872	2998.11	05/17/1998

Schedule Fee($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.09	1.399	7.025	30.003	05/19/1998

Reactive Voltage($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.034	0.982	5.627	24.09	05/19/1998

Loss Percentage		
On-Peak	Off-Peak	Last Updated
-4.6%	-1.59%	05/31/1998

Back to Price Matrix
Back to OASIS

Prices based on 1 MW

*The Southwest Power Pool administration fee is $0.15 per MWH.
**The rates provided are an approximation for transmission service charges for SWPP. This estimate is based on the most recent transmission ownership, power flow, and date submitted for MW-Mile calculation and the charges set forth by SWPP.
***The rates provided are not to be constructed as a quote. actual charges may vary depending upon the data available at billing time.

The prices shown above are from the SPP Price Matrix for the summer months June through September.

NEW CENTURY ENERGIES

PUBLIC SERVICE COMPANY OF COLORADO

SOUTHWESTERN PUBLIC SERVICE COMPANY

CHEYENNE LIGHT FUEL & POWER

PO Box 1261
Amarillo Texas 79170-0001
Telephone 806.378.2121

August 21, 1998

UtiliCorp Energy Group
Attn: Mr. Frank A. Debacker
107500 East 350 Highway
Kansas City, Missouri 64138

RE: Proposal Clarification, SPS bid dated July 3, 1998 for capacity and energy to Missouri Public Service Company ("MPS").

Dear Frank,

In response to your questions concerning the reserves associated with the firm power option, SPS has the following response.

For the firm power associated with "Option A – Partial Requirement Power Service, with Peaking Power Service," SPS will carry the pool planning reserves, in accordance with the current rules and procedures of the Southwest Power Pool ("SPP"), which is currently 12%. Therefore, if MPS purchased 100MW of firm capacity under the terms of Option A, SPS will carry an additional 12 MW in planning reserves.

This definition of reserves and firm capacity apply to the attached revised bid. If you have any questions, please feel free to call me at 806-378-2376.

Sincerely,

Mike Martin
Regional Power Sales Representative

mm
cc: Todd Hegwer

NEW CENTURY ENERGIES

PUBLIC SERVICE COMPANY OF COLORADO
SOUTHWESTERN PUBLIC SERVICE COMPANY
CHEYENNE LIGHT FUEL & POWER

PO Box 1261
Amarillo, Texas 79170-0001
Telephone 806.378.2121

August 21, 1998

UtiliCorp Energy Group
Attn: Mr. Frank A. Debacker
107500 East 350 Highway
Kansas City, Missouri 64138

RE: Purchase of Resource Specific Capacity and Energy for the period June 1, 2000, through May 31, 2001.

In response to UtiliCorp Energy Group's ("UEG") request for proposals, Southwestern Public Service Company ("SPS") will agree to sell the following resource specific capacity and energy to UEG's operating division Missouri Public Service ("MPS") under the terms presented herein, pursuant to and in accordance with SPS' Market Based Tariff. Terms used, but not defined herein shall have the meaning ascribed to them in the definitive agreement. Information contained in this response is to be used solely by UEG for evaluation purposes only and contains privileged and confidential information not to be shared with third parties without prior written consent of SPS. This offer for resource specific capacity and energy cancels and supercedes SPS' offer to MPS dated July 3, 1998.

PARTIAL REQUIRMENT POWER SERVICE

The term "Partial Requirements Power Service" shall mean that quantity of firm electric power and associated energy that SPS will make continuously available to UEG and which will meet the capacity and energy needs of UEG.

Contract Period: The months of June 1, 2000 through May 31, 2001.

Partial Requirements Capacity Amounts: As per the following Table 1:

TABLE 1	
Period	Capacity
June 1, 2000 - May 31, 2001	50 MW, up to 100 MW, in whole MW increments

Partial Requirements Capacity Charge: The price of the Partial Requirements Power Service Capacity is as shown in the Table 2:

TABLE 2	
Period	Capacity
June 1, 2000 - May 31, 2001	$ 5,200/MW - Month

Partial Requirements Energy Price: The price of energy delivered to UEG shall be $0.80/MWh plus the Wholesale Fuel Cost Adjustment Factor.

Wholesale Fuel Cost Adjustment Factor: Attachment 1 is a copy of SPS' Wholesale Fuel Cost Adjustment (FCA) Clause currently in effect. Table 3 shows an estimate of the anticipated Wholesale FCA for the months shown.

TABLE 3	
Year	Projected Wholesale FCA Factor ($/MWh)
June, 2000	19.74
July, 2000	19.89
August, 2000	19.84
September, 2000	19.49
October, 2000	19.95
November, 2000	20.92
December, 2000	20.48
January, 2001	20.77
February, 2001	20.09
March, 2001	19.46
April, 2001	19.41
May, 2001	19.55

Unless another method is mutually agreed upon, SPS will notify UEG of the estimated Wholesale FCA Factor prior to the upcoming month. Any deviations from the actual to the estimated Wholesale FCA Factor shall be accounted for in the month immediately following.

Point of Supply: The Points of Supply shall be the generator bus, or busses, from any of SPS generation resources. UEG shall be responsible for reimbursing SPS for the cost of firm transmission and ancillary services through SPS from any of SPS' generation resources to the MPS transmission system, including losses, as outlined in the section entitled "Transmission and Ancillary Services."

Availability: In the case of Partial Requirements Power Service, with Peaking Power Service, SPS defines availability as the amount of available capacity from SPS generation resources designated to deliver energy to its firm customers. As long as SPS has generation available to its firm customers, SPS will supply the energy.

Partial Requirements Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am Central Prevailing Time for all energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule Partial Requirements Energy on an emergency basis (i.e. only two hours notice), SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall be 10 MW for one hour. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

TRANSMISSION AND ANCILLARY SERVICES

As per Section C and G of the UEG's request for proposals, SPS will provide for transmission and ancillary services from the Point of Supply to the Point of Delivery under separate agreements, under which UEG shall reimburse SPS the total costs incurred for these services. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction. To help UEG in the evaluation of this proposal, the costs from the transmission and ancillary service providers are shown in Attachment 2. SPS will work closely with UEG to ensure the most reliable and economical transmission and ancillary services are acquired for this agreement.

UEG may request SPS deliver energy, under terms of this agreement, to UtiliCorp's West Plains Energy – Kansas Division (WPEKS), subject to the availability of SPS' transmission and regulatory conditions that may impact both MPS and WPEKS. SPS would also like to point out that flows from SPS to MPS, scheduled through WPEKS, will have the net affect of displacing generation and energy from the Jeffrey Energy Center in Central Kansas, of which MPS currently derives a portion of its total capacity resources.

The cost of the energy from the options listed above does not take into account the effect of the losses incurred when transmitting electrical energy across various transmission systems. UEG, at its choosing, can either 1) take receipt of the energy at the Point of Delivery minus an amount of energy equal to the losses incurred to deliver the energy, 2) purchase the losses, through SPS, from the regional transmission providers, or 3) purchase the losses directly from the regional transmission providers.

SPS understands that these terms and conditions are subject to review and approval by UEG as stated in the request for proposal. This proposal is valid through September 30, 1998 and is subject to prior sale and the completion of a definitive agreement, management approvals, and the availability of transmission and ancillary services from SPS and any other transmission provider from which transmission services are necessary to deliver firm capacity and energy to UEG.

If you have any questions, comments, or need additional information, please feel free to call me at 806-378-2376.

Sincerely,

Mike Martin

Mike Martin
Regional Power Sales Representative

cc: Todd Hegwer

ATTACHMENT 1

Southwestern *PUBLIC SERVICE* Company

COMMISSION	SCHEDULE	SHEET	RATE SCHEDULE NUMBER	
~~FERC~~				

WHOLESALE FUEL COST ADJUSTMENT CLAUSE

TARIFF NUMBER	~~7105.1~~
CANCELLING	~~7105.0~~

1. The charges for actual wholesale service rendered during the current billing period shall be increased or decreased by an adjustment amount, per kilowatt-hour of sales (to the nearest 0.0001¢), equal to the difference between the estimated fuel cost (eF) per kilowatt-hour of estimated sales (eS) in the current, or billing, period (m) and the base period (b), as adjusted to allow for wholesale losses (L), with the total charges adjusted by a dollar amount to correct for prior wholesale over or under collections:

$$\text{Adjustment Factor} = \left[\frac{eFm}{eSm} - \frac{eFb}{eSb}\right] (L)$$

2. Fuel costs (F) shall be the cost of:

   (i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

   (ii) Plus, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. Included therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.

   (iii) Plus, the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such charges), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as:

      (1) charges incurred for economy energy purchases and

      (2) charges incurred as a result of scheduled outages,

   all such kinds of energy being purchased by the Company to substitute for its own higher cost energy.

Effective Date January 1, 1990　　　Approved Bill D. Helton

TAR62

(iv) Less, the cost of fossil and nuclear fuel recovered through inter-system sales, including the fuel costs recovered from economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be equated to:

(i) the sum, measured at the bus-bar or interconnection point, of (1) generation, (2) purchases, and (3) interchange-in,

(ii) less (1) inter-system sales, as referred to in 2.(iv) above, and (2) inter-system losses.

4. "L", the adjustment for wholesale losses, determined at the wholesale delivery points, shall be equal to:

$$1.039 = \frac{1}{1 - 3.754\%}$$

5. The current month adjustment for prior wholesale over or under collections shall be calculated as:

(i) the first prior month's (p) actual fuel costs (aF) divided by actual sales (aS),

(ii) minus that month's (p) estimated fuel costs (eF) divided by estimated sales (eS),

(iii) times the wholesale loss adjustment (L),

(iv) times actual wholesale sales (W) in that month (p) for each customer.

$$\text{Adjustment Amount} = \left[\frac{aFp}{aSp} - \frac{eFp}{eSp}\right] (L)\ (Wp)$$

The adjustment amount shall be debited or credited to the current month's billing.

6. (i) The fuel cost adjustment factor calculation shall not include:

(1) the net energy cost of electric energy purchased from Celanese Corporation and,

(2) the kilowatthours generated at the Celanese Corporation chemical plant, not to exceed the amount of electric energy consumed at that plant.

(ii) The fuel cost adjustment factor calculation shall include both the net energy cost of energy purchased from Celanese, and the kWh generated at its plant, for any amount of energy which does exceed the amount consumed at that plant.

ATTACHMENT 2

Transmission and Ancillary Service Charges: The following table outlines the various charges to deliver the capacity and energy to MPS:

Southwestern Public Service	**Demand Charge**	**Energy Charge**
Firm Transmission	$1,358/MW - month	
Scheduling	$28.9/MW - month	
VAR/Voltage Support	$34.6/MW - month	
Losses	See Note 1.	
West Plains Energy – KS (WPEKS)		
Firm Transmission	$1,083/MW - month	
Scheduling	$54.0/MW - month	
VAR/Voltage Support		$0.190/MWh
Losses	See Note 2.	
Western Resources, Inc. (WRI)		
Firm Transmission	$1,300/MW - month	
Scheduling		$0.1561/MWh
VAR/Voltage Support	$39.47/MW - month	
Losses	See Note 3.	
Central and Southwest (CSW)		
Firm Transmission	$1,100/MW - month	
Scheduling	See Note 4.	
VAR/Voltage Support	See Note 5.	
Losses	See Note 6.	

Note 1: Losses for SPS system are as follows:
Demand Related Loss Factor is 3.6984%
Energy Related Loss Factor is 4.4863%

Note 2: Losses for WPEKS are 6.0% in the months May - October, 5.0% in the months November - April.

Note 3: Losses will be as follows (from WRI's OA Tariff):

Real Power Losses shall be calculated by multiplying the capacity and energy received at the Receipt Points by the applicable Real Power Loss factors stated below for the voltage at the Point of Receipt or Point of Delivery, whichever is lower. For deliveries to a Control Area interface, the Real Power Loss factor shall be the average of the applicable factors stated below for each interconnection within the interface.

Voltage	Meter Location	Transmission Losses
230-345 KV	High Side	0.87%
	Low Side	1.62%
115-161 KV	High Side	1.62%
	Low Side	3.04%
34.5-69 KV	High Side	3.04%
	Low Side	4.43%

Where:

"High Side" refers to a line tap meter location at the stated voltage or, in the case of a delivery point requiring the use of a step-down transformer, to the high voltage side of such transformer.

"Low Side" refers to a meter within a substation and located on the low voltage side of a step-down transformer.

"Bus" refers to a meter within a substation and located on the substation bus at the stated voltage.

"Circuit" refers to a line tap meter location at the stated voltage.

Note 4: CSW charges $66/transaction/day for each schedule across CSW's transmission system within the SPP.

Note 5: As per CSW's OA Tariff, "Reactive Supply and Voltage Control from Generation Sources Service will be provided directly by PSO/SWEPCO as the Control Area operator. The Transmission Customer must purchase this service from PSO/SWEPCO. PSO/SWEPCO will not impose a separate charge for Reactive Supply and Voltage Control from Generation Sources Service."

Note 6: The Loss Factors on the CSW's alternating current facilities in the SPP are as follows:

Energy loss factor: 2.0%

The Transmission and Ancillary Service Charges are based on the SPS', WRI's, CSW's and WPEKS' open access tariffs. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction.

Based on the firm transmission charges from SPS' generating resources, the most cost effective path to MPS is from SPS through WPEKS and WRI, although an alternate path from SPS through CSW and WRI is available. Actual paths and charges will depend upon the various Available Transmission Capacity (ATC) between the above transmission providers at the time transmission is requested and/or obtained.