Non-Proprietary

Support for the EWG Build

Data Request No. 607

Missouri Public Service Commission

Respond Data Request

Data Request No.	0607
Company Name	Aquila, Inc.-Investor(Electric)
Case/Tracking No.	ER-2004-0034
Date Requested	12/02/2003
Issue	Expense - Operations - Purchase Power
Requested From	Denny Williams
Requested By	Cary Featherstone
Brief Description	Support for the EWG Build Option
Description	With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.
Response	See attached Word doc from Frank DeBacker for response. Hard copy of detail sent to staff.
Objections	NA

The attached information provided to **Missouri Public Service Commission** Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the **Missouri Public Service Commission** if, during the pendency of Case No. **ER-2004-0034** before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information. If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the **Aquila, Inc.-Investor(Electric)** office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to **Aquila, Inc.-Investor(Electric)** and its employees, contractors, agents or others employed by or acting in its behalf.

Security :	Public
Rationale :	NA

With Proprietary and Highly Confidential Data Requests a Protective Order must be on file.

Schedule 1-2

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-607

DATE OF REQUEST:	December 2, 2003
DATE RECEIVED:	December 2, 2003
DATE DUE:	December 22, 2003
REQUESTOR:	Cary Featherstone
BRIEF DESCRIPTION:	Support for the EWG Build Option

QUESTION:

With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.

RESPONSE:

1. Analyses relating to the need for additional power supply resources for Missouri Public Service was communicated to Staff and OPC through the following:
   Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, with a copy to Ryan Kind, OPC.
   Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998
2. Any notes taken at the referenced meeting are no longer available.
3. Any letters, e-mail, correspondence, and other communication are no longer available.

ATTACHMENT:

Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, with a copy to Ryan Kind, OPC.

Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998

ANSWERED BY: Frank DeBacker

Frank DeBacker

SIGNATURE OF RESPONDENT

ER-2004-0034
MPSC-607
Attachment #1

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

April 7, 1998

UTILICORP UNITED
ENERGYONE

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

RE: Missouri Public Service Request for Proposal

Dear Mr. Proctor:

After our meeting on March 31, MPS was notified that KCPL was withdrawing its proposal to provide firm summer peaking energy to MPS for the years 2000 and 2001.

As a consequence, MPS need for additional power supply resources is 325 MW in 2000 and 500 MW in 2001. This need is based on current load growth forecasts and the expiration of the following purchase power contracts:

Provider	Megawatts	Expiration Date
KCPL	90	September 30, 1999
AECI	190	May 31, 2000
UE	115	May 31, 2001.

The enclosed Request for Proposal (RFP) is hereby submitted to the MPSC staff and the OPC for review and comment.

MPS intends to incorporate any comments received from the MPSC staff and the OPC and issue the RFP on May 29, 1998. Proposals will be due on July 3, 1998.

Please call me at (816) 936-8639 with any comments, suggestions or questions.

Sincerely,

Frank A. DeBacker
VP - Fuel & Purchased Power

Attachment

cc: Mr. Ryan Kind, Office of the Public Counsel w/ attachment
Mr. John McKinney, UCU w/ attachment

Request for Proposals
for
Resource Specific Capacity & Energy
for
Missouri Public Service

MPS-1998RFP

Spring, 1998

A. General

UtiliCorp Energy Group is issuing this Request For Proposal (RFP) on behalf of Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU).

MPS is an integrated electric and gas utility located in western Missouri and is a member of the Southwest Power Pool and the MOKAN power pool.

The following RFP is for both annual and seasonal **Resource Specific Capacity and Energy** resources. Financially firm energy proposals will not be accepted.

Resource Specific means the successful bidder must state the actual power supply resource(s) that will provide the capacity and energy requested. The resource(s) need not be stated in the proposal; however, the resource(s) must be named and listed in any contract which may result from this solicitation.

This RFP is not a contract. Any contract(s) which may result from this RFP shall be in accordance with mutually agreeable, specific terms and conditions developed between UtiliCorp and the successful bidder(s). In addition, any contract(s) resulting from this RFP shall be subject to the approval of all regulatory bodies having jurisdiction.

UtiliCorp reserves the right to reject any or all proposals at its sole discretion.

Proposals shall be addressed to the following and must be received no later than 5:00p.m. C.D.S.T., July 3, 1998.

UtiliCorp Energy Group
Attn: Frank A. DeBacker
10700 East 350 Highway
Kansas City, MO 64138
Ph: (816) 936-8639
Fax: (816) 936-8695
E-mail: fdebacke2@utilicorp.com

B. Contract Capacities and Periods

Proposals are requested for the seasonal and annual capacity amounts shown in Table 1.

Note that the amounts shown are not mutually exclusive. For example, assuming that appropriate proposals are submitted, UCU may elect to purchase one of the following portfolios to meet the needs of MPS from 6/1/2000 - 5/31/2001:

- 100 MW of Jun-May capacity, 50 MW of Oct-May capacity and 175 MW of Jun-Sep capacity; or,
- 325 MW of Jun-Sep capacity and 75 MW of Oct-May capacity; or,
- 325 MW of Jun-May capacity.

Table 1: MPS Capacity Need

Contract Period		Capacity Amount (MW)		
From	To	Jun-Sep Capacity	Oct-May Capacity	Jun-May Capacity
6/1/2000	5/31/2001	Up to 325	Up to 75	Up to 325
6/1/2001	5/31/2002	Up to 500	Up to 250	Up to 500

C. Point(s) of Delivery

The point(s) of delivery shall be the interconnection point(s) of the MPS transmission system with the Eastern Interconnection.

D. Capacity Pricing

Capacity price at the point(s) of delivery **must** be stated in $/MW-mo, fixed for the contract term.

E. Energy Pricing

Bidders are encouraged to submit creative pricing proposals. The energy price must be for energy delivered at the Point(s) of Delivery. Energy prices may be fixed or based on regionally recognized indices. The energy pricing methodology must enable UtiliCorp to determine the energy price prior to submitting a purchase schedule per Section H below.

Bidders may propose a variety of energy pricing methodologies which may include, but are not limited to, the following elements:

On peak/off peak price
Constant price
Monthly price
Index price
Resource heat rate
Resource variable O&M costs

The bidder shall provide any formula(s) used to calculate the energy price. The bidder shall include the values of any constants and a definition of all variables which make up the formula(s).

F. Transmission

The successful bidder shall provide firm transmission service from the proposed resource(s) to the Point(s) of Delivery.

G. Scheduling

Proposals which allow hourly schedule changes are preferred; however, UCU will consider any and all scheduling proposals. Bidders shall state what scheduling requirements are proposed. At a minimum, proposed requirements on the following items must be included in bidders proposal:

Resource Start up costs, if applicable
Minimum purchase schedule
Minimum load factor & measuring period
Maximum load factor & measuring period
Minimum schedule block
Initial schedule submittal procedure
Subsequent schedule change procedure
Energy Block Requirements (ie: 7x24, 5x16, etc.)

H. Availability

Bidders **must** state and define the guaranteed availability level for the resource(s) that will provide the capacity and energy proposed.

The successful bidder **will be required** to reimburse UtiliCorp any incremental cost incurred to acquire replacement capacity and energy due to the bidder's failure to meet its availability guarantees.

Bidders shall provide the proposed maintenance schedule for unit contingent resource(s).

I. UCU Proposal & Joint Projects

UCU may elect to submit an EWG proposal in response to this RFP. If it chooses to submit a proposal, all proposal evaluations will be performed by an independent third party approved by the Missouri Public Service Commission

(MPSC). Any contract between MPS and the EWG would be subject to the approval of the MPSC.

Proposals for joint projects which would provide partial ownership through equity participation by UCU are invited. Such projects would also be evaluated by an independent third party and any contract subject to the approval of the MPSC.

J. Contact

For additional information regarding this RFP, contact Frank A. DeBacker through the means listed in Section A above.

ER-2004-0034
MPSC-607
Attachment #2

UTILICORP UNITED INC.

MISSOURI PUBLIC SERVICE

1998-2003
PRELIMINARY
ENERGY SUPPLY PLAN

August 24, 1998

Table of Contents

1. EXECUTIVE SUMMARY

1.1 Objectives

UtiliCorp's regulated electric operations for its Missouri Public Service division (MPS) face a 250+ MW shortfall of capacity and associated energy in the year 2000. This shortfall will grow to over 480 MW by the summer of 2003. The capacity shortfall is principally driven by the expiration of three purchase power contracts which total 295 MW in 1999 and the expiration of leases on 272 MW of peaking capacity.

The principle objective of the 1998-2003 Missouri Energy Supply Plan is the acquisition of incremental capacity and associated energy which will:

- Provide a cost effective energy supply to MPS electric customers in the short term; and,
- Assure that supply resources acquired have the ability to successfully compete in future deregulated energy supply markets.

1.2 Planning Process

The MPS energy supply analysis began with market and resource need analysis which included:

- Load Forecast, 1998-2017
- National and Regional Capacity & Energy Price Forecasts
- MPS Supply Requirements
- MPS Supply Resources

Based on the future supply needs of MPS, three supply options were considered:

- Purchase Power Contracts
- Simple Cycle Combustion Turbine Peaking Units
- Combined Cycle Combustion Turbine Units

As an initial step in meeting the MPS capacity and energy needs, a Request for Proposals (RFP) was issued on May 22, 1998 which solicited proposals to supply MPS' incremental capacity needs in the years 2000 - 2003. Proposals were received on July 3, 1998.

In conjunction with the issuance of the RFP, projections of the market clearing prices for MPS and the adjoining regional markets were prepared along with ownership cost estimates for the following resources:

- 1x100 MW Simple Cycle Combustion Turbine Unit
- 1x165 MW Simple Cycle Combustion Turbine Unit

- 2x165 MW Simple Cycle Combustion Turbine Units
- 1x250 MW Combined Cycle Unit
- 2x250 MW Combined Cycle Units

The proposals received in response to the RFP were evaluated by Burns & McDonnell and compared to the cost to supply energy from the most competitive of the five UCU owned resource options listed above. A draft report outlining the results of the analysis conducted by Burns & McDonnell is attached as Appendix A.

The result of the above analysis is a preliminary supply plan which will meet all of MPS' capacity and energy needs through 2003 and a major portion of its needs thereafter. Conclusions and a recommended action plan are contained in sections 1.4 and 1.5 respectively.

1.3 Assumptions

Key data assumptions utilized in the analysis are shown in the following table.

Table 1.3-1: Data Assumptions

Topic	Assumptions
Inflation Rates (1998-2013)	CPI: 2.5% Construction Costs: 2.5% O&M Costs: 2.5%
Cost of Capital	Debt: 50% @ 7.0% Equity: 50% @ 11% IRR Discount Rate: 10%
Fuel Price Escalation (1994-2013) - Real 2.50%	Natural Gas: Real + 0.50% PRB Coal: Real - 0.50% Hanna Coal: Real - 0.50%
Reserve Margin	13.0% Reserve Margin
Financial Data	Federal Tax Rate - 35% State Eff. Tax Rate - 5% (MO)

1.4 Conclusions

Based on the 1998-2003 supply-side analysis, the least-cost plan for MPS consists of executing short term purchase contracts to meet MPS capacity needs through the year 2000, and the construction of a gas-fired 500 MW combined cycle unit to meet all of MPS' capacity needs in the 2001-2003 time frame and a majority of its needs thereafter.

The above supply plan provides the least cost means to meet the MPS capacity and energy needs even though MPS' has a low annual load factor of <50% and an abundant supply of low-cost energy supplied by its existing resource base which is 64% coal-fired base load generating capacity.

abundant supply of low-cost energy supplied by its existing resource base which is 64% coal-fired base load generating capacity.

The ability of combined cycle units to compete in the regional energy market place enables these resources to provide sufficient revenue to offset their higher capital cost.

1.5 Recommended Action Plan

As a result of the analysis outlined in this report, it is recommended that UCU:

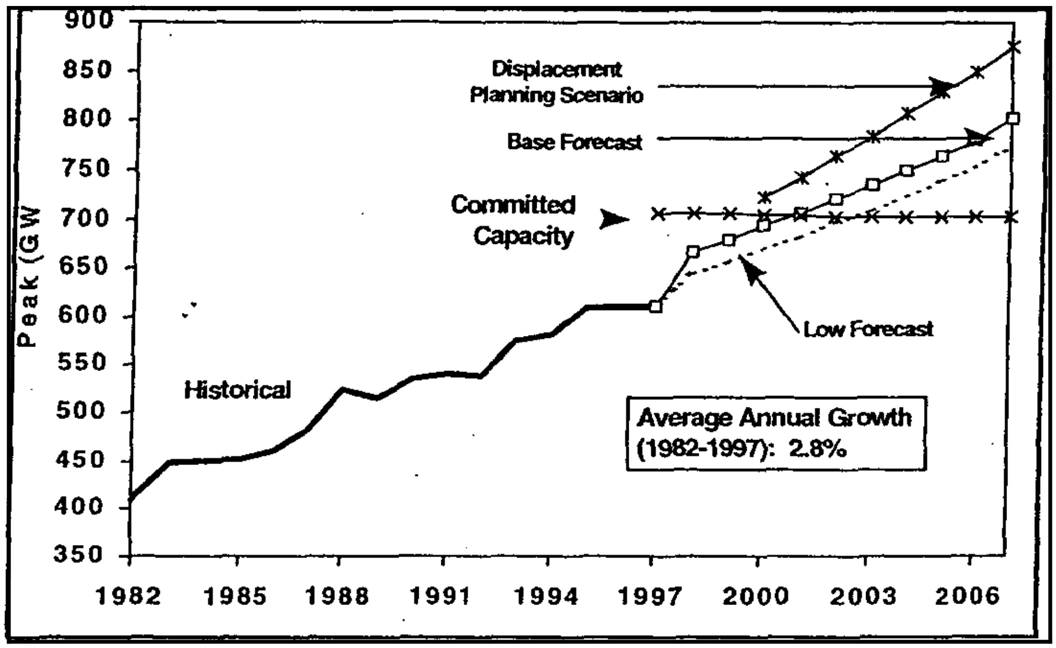
- Negotiate extension of the existing lease agreements on the Greenwood combustion turbines.
- Secure short term capacity to meet MPS' capacity needs thru 2000.
- Pursue the construction of a 500 MW combined cycle unit proposed with an in service date of June 1, 2001.

2. RESOURCE NEED ANALYSIS

2.1 National and Regional Forecasts

United States capacity supply needs in the 2001 - 2007 time frame are projected to be 100 - 175 GW in excess of existing and committed capacity. If displacement of inefficient fossil and nuclear generation is considered the shortfall increases an additional 40-50 GW. Chart 2.1-1 presents this data in graphical form.

Chart 2.1-1: U.S Projected Capacity Short Fall



On a national basis, U.S. and Canadian capacity reserve margins have been decreasing for the past fifteen years. In the U.S., reserve margins will fall below ten percent around turn of the century. Chart 2.1-2 shows the projected reserve margins for both the U.S. and Canada. Note the dramatic impact of premature nuclear retirements on the reserve margins of both the U.S. and Canada.

On a regional basis, the decline in the reserve margin becomes more dramatic in many regions of the U.S. Reserve margins are projected to fall below zero by 2002 in ECAR, MAPP, MAIN and portions of SERC. Table 2.1-3 presents the reserve margin for all NERC regions and sub-regions of the U.S.

Chart 2.1-2: Projected U.S. & Canadian Reserve Margins

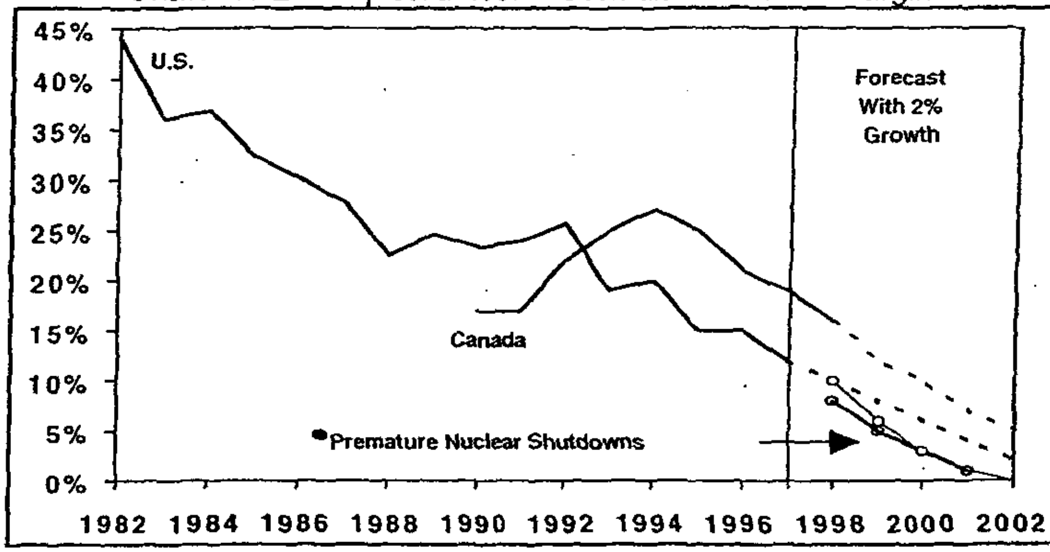


Table 2.1-3: Projected U.S. Regional Reserve Margins

Region	Reserve Margin (%)			
	1995	1998	2002	2002 NS*
ECAR	11.5	8.5E	-2.6	-3.2
ERCOT	18.5	14.8E	3.4	3.4**
MACC	15.4	14.0	2.7	1.6
MAIN	11.1	6.8	-4.3	-12.1
MAPP	11.3	4.1E	-3.6	-13.4
NPCC	30.0	24.0	11.7	2.7**
- NY	30.8	23.3	12.0	6.2**
- NEPOOL	28.8	24.0	11.4	-7.5**
SERC	10.3	8.2E		
- Florida	9.0	7.1E	3.1	3.1**
- Southern	9.9	0.5E	-11.0	-11.0
- TVA	0.7	5.6	-3.1	-3.1
- VACAR	21.3	17.7E	6.6	6.6
SPP	14.5	13.0	2.0	1.0
WSCC	-	-	-	-
- Northwest	17.6	11.1E	3.5	3.5
- California	14.8	13.9E	3.2	3.2**
- AZ/NM	10.7	14.4E	3.5	3.5
- Rockies	22.7	22.0	10.6	10.6

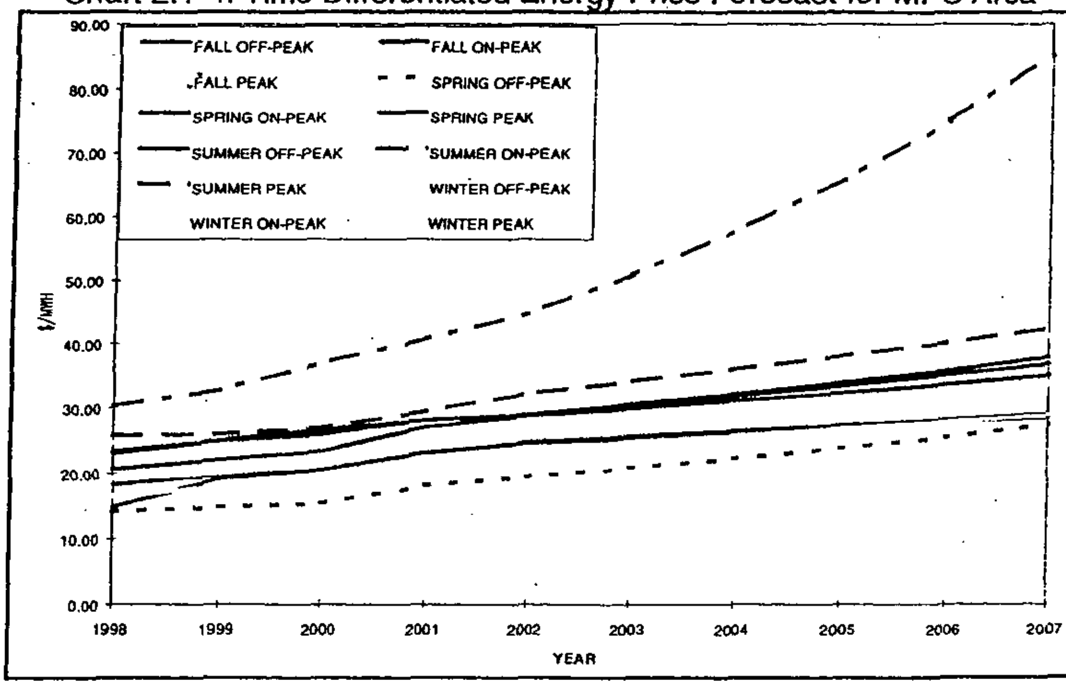
*With Premature Nuclear Shutdowns (NS)
**Region also includes inefficient Fossil capacity with potential for displacement.

Projections of the regional marginal energy price are key to the determination of the profitability of generation resources in a competitive marketplace. To obtain an unbiased forecast of marginal energy prices, the firm of Hill & Associates was retained in December, 1997 to prepare a forecast for the years 1998 - 2017. Key financial and fuel price assumptions for the forecast are shown in Table 1.3-1 in section 1.3. The other major driver in the forecast is the timing of additional generation resources. For the purpose of this forecast, additional generation capacity was added when the average annual marginal energy price in a region reached $26.00/MWh in 1997 dollars. In order to obtain more accurate pricing of seasonal and time of day energy cost, each year was divided into four seasons (summer, fall, winter and spring) and each season divided into three time periods:

Off peak	Midnight to 8AM
On Peak	8AM - Midnight, except 3PM - 6PM
Peak	3PM - 6PM

Chart 2.1-4 shows the projected marginal energy cost for the MPS area for the years 1998 - 2007. Projected prices for the northern region of the SPP are similar.

Chart 2.1-4: Time Differentiated Energy Price Forecast for MPS Area



2.2 MPS Capacity Needs

Table 2.2-2 provides a summary of the MPS loads and resources forecast for MPS over the 1998-2004 planning horizon. The forecast assumes that MPS will be successful in retaining the peaking capacity associated with the leased units. New capacity of 256 MW will be required by 2001 to meet MPS' projected capacity needs. This need will grow to 480 MW by the summer of 2003.

Table 2.2-1: MPS Loads & Resource Summary

Year>>	1998	1999	2000	2001	2002	2003	2004
MPS Demand Forecast in MW							
Base Forecast	1,167	1,203	1,237	1,268	1,297	1,331	1,369
Less Interruptables	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Net	1,162	1,198	1,232	1,263	1,292	1,326	1,364
MPS Generation Capacity in MW	1,045	1,045	1,045	1,045	1,045	1,045	1,045
MPS Purchased Capacity in MW	345	395	115	-	-	-	-
MPS Total Capacity in MW	1,390	1,440	1,160	1,045	1,045	1,045	1,045
Capacity Margin in MW	228	242	(72)	(218)	(247)	(281)	(319)
Required Capacity Margin in MW	174	179	184	189	193	198	204
Capacity Surplus (Deficit)	54	63	(256)	(407)	(440)	(479)	(523)

3. EXISTING SUPPLY RESOURCES

3.1 Generation

During 1997, UtiliCorp's Missouri Public Service (MPS) electric operations consisted of 14 generating units with an accredited capacity of 1,045 MW. Actual system coincident peak load was 1,131 MW in July 1997. Actual system load factor was 47%, based on net energy for load of 4,657,936 MWH dispatched. The MPS capacity mix was 36% peaking capacity and 64% base load capacity in 1997. MPS' single largest generating unit is the coal-fired Sibley Unit 3, which has a net rated capacity of 396 MW. MPS' other coal-fired resource is its 176 MW ownership in the Jeffery Energy Center. MPS also owns 105 MW of peaking capacity and leases an additional 267 MW of peaking capacity.

3.2 Purchased Power Contracts

MPS purchases capacity and energy through purchase power contracts with three neighboring utilities.

The first contract is with Associated Electric Cooperative (AEC). Capacity and energy are purchased under an agreement executed in 1987, and amended in 1988, 1989 and 1994. The AEC purchase contract expires on May 31, 2000, at which time the contract capacity amount totals 190 MW.

The second contract is with Union Electric (UE). Capacity and energy are purchased under an agreement executed in 1987. The UE purchase contract expires May 31, 2001, at which time the contract amount totals 115 MW.

The third contract is with Kansas City Power and Light (KCPL). Capacity and energy are purchased under an agreement executed in 1997. The KCPL contract expires on September 30, 1999, at which time the contract capacity amount totals 90 MW.

The following table summarizes the purchased capacity amounts from the AEC, UE and KCPL contracts available in the years 1997 - 2000:

Table 3.2-1: MPS Purchase Power Contracts

Year (June 1)	AEC Contract (MW)	UE Contract (MW)	KCPL Contract (MW)	Total (MW)
1997	150	115	30	295
1998	170	115	60	345
1999	190	115	90	395
2000	--	115	--	115

3.3 Power Plant Improvements

The supply-side resource analysis included identification of specific re-powering and equipment modification options for existing MPS generating resources. These power plant improvement options have been identified based on inquiries to equipment manufacturers. The cost estimates for these options are too preliminary to quantitatively analyze them in the supply-side resource analysis at this time. It should be noted that the total of potential capacity increase of 54 MW represents only 10 percent of MPS' incremental capacity need through 2001.

A. New High Flow Inlet Guide Vanes - Greenwood (8 MWs)

Combustion turbine inlet guide vanes (IGVs) act as air flow limiters during startup and low load operations. This necessary feature for low load situations can penalize full load capacity by restricting air flow. IGVs are an item typically requiring replacement due to fatigue. Using new alloys, thinner IGVs can replace the originals and provide greater air flow and with it higher capacity. These potential modifications at the Greenwood Plant have the advantages of not impacting O&M, emissions rates, or operating procedures.

B. Water Injection - Greenwood (12 MWs)

The capacity of a combustion turbine is directly proportional to the mass flow through the turbine. Water can be injected at the turbine inlet through the fuel nozzle to increase the mass flow. The advantages of this modification at the Greenwood Plant are that it lowers NOx, is easily dispatched, and has industry acceptance. Disadvantages are the delivery, handling, storage and processing of the water, and water injection has a negative impact on the turbines heat rate.

C. Upgrade Jet Engines - KCI Airport (4 MWs)

The jet engines at Kansas City International (KCI) Airport are late 1960s vintage. The manufacturer made improvements to these engines throughout the 1970s. In general, the capacity of these units is limited by the firing temperature. Replacing the units' blades and vanes with higher temperature components will allow the units to operate at higher temperatures. The advantage of these modifications to the KCI jet engines include no impacts to O&M, operating procedures, or emissions rates. Upgrades during 1995 totaling 10 MW to the existing KCI Units 1 and 2 are included in the existing resources.

D. Boiler/Turbine Upgrade - Sibley (30 MWs)

The turbine manufacturer, Westinghouse, and the boiler manufacturer, Babcock & Wilcox, have indicated that additional capacity can be achieved through modifications to their equipment and some plant auxiliaries. Evaluation will include impact on fuel blend, emission rates, heat rate and total installed cost.

3.4 Combustion Turbine Lease Renewal

MPS currently leases the majority of its combustion turbine capacity. The following table shows the unit, capacity and current lease termination date for these units.

Table 3.4-1 Leased Combustion Turbine Data

Unit Name	Capacity (MW)	Lease Termination
Nevada	20	June, 1999
Greenwood #1	62	June, 2000
Greenwood #2	62	June, 2000
Greenwood #3	62	June, 2002
Greenwood #4	61	June, 2004

The following action plan has been initiated to determine whether UCU should renew the leases, terminate the leases or purchase the units.

- Determine the market value of the units to the lease holders.
- Determine the value of the capacity to MPS.
- Develop Renegotiation Strategy

The above process revealed a gap between the value of the units to the lease holders and the value to MPS with the value to MPS being approximately twice the market value of the units to the lease holders. Using this information, a strategy was developed which will offer the following options to the lease holders:

1) Purchase the units at a price that is equivalent to the NPV of the five year lease payments; or,
2) Lease the units for five years for a lease payment stream which will have the same NPV as the unit's fair market value.

Based on its analysis of the inability of simple cycle combustion turbine technology to compete in a deregulated marketplace and the age of the leased units, option 2 is the preferred option.

The following table shows the time line for completion of the action plan.

Table 3.4-2: Timetable for CT Lease Renewal/Purchase

Activity	Date
Complete Market Value Study	June 15, 1998
Complete Lease/Buy Analysis	June 30, 1998
Complete Nevada Negotiations	December 1, 1998
Complete GEC 1 & 2 Negotiations	December 1, 1999
Complete GEC 3 Negotiations	December 1, 2001
Complete GEC 4 Negotiations	December 1, 2003

4. FUTURE SUPPLY OPTIONS

4.1 Introduction

As mentioned in section 1.2, two types of future UCU-owned supply resources were evaluated. This section provides technology descriptions for each of these resources. Cost data and operating characteristics are presented for the UCU-owned supply resources which are shown in Table 4.1-1.

Table 4.1-1: UCU Owned Supply-Side Resources

Description	Service Class	Construction Cost in $/kw	Ownership Cost in $/kw-mo. @ 11% IRR
1x100 MW CT	Peaking	$294	~$4.25
1x165 MW CT	Peaking	$263	~$4.00
2x165 MW CT	Peaking	$259	~$4.00
1x242 MW CC	Intermediate	$425	~$6.40
2x242 MW CC	Intermediate	$361	~$5.50

4.2 Peak Load Supply Resources

Combustion Turbine

Combustion turbines consist of an air compressor, a combustion chamber, and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustion chamber, producing hot gases that pass through an expansion turbine, driving an air compressor and an electrical generator. This arrangement, with no recovery of the energy contained in the high temperature exhaust gases, is referred to as a simple cycle.

The combustion turbine technology is a mature technology which has quick starting capabilities, ease of siting, low capital costs, relatively short construction time, and lower air emissions than coal-fired resources. However, the units burn natural gas or oil which are relatively costly fuels subject to substantial price fluctuations. Combustion turbines thus have high operating costs at higher capacity factors.

4.3 Base & Intermediate Load Supply Resources

Combined Cycle

A combined cycle facility includes a combustion turbine, a heat recovery steam generator (HRSG) and a conventional steam turbine. Exhaust gases from the combustion turbine are used to generate steam in the HRSG, which powers the steam turbine. Combined cycle is a mature technology with numerous facilities operating throughout the United States.

The combined cycle has greater efficiency than the combustion turbine, has a short construction time, can be constructed in stages, and has lower air emission rates than conventional steam turbine generation units. Combined cycle units can be designed to burn a variety of fuels including natural gas, syngas, biogas and fuel oil.

The current combined cycle technology has demonstrated NOx emissions as low as 9 PPM without SCR or water injection and the thermal cycle efficiency is approaching 60 percent (LHV).

With the addition and expansion of digital based control systems combined cycle plants can deliver an average annual availability greater than 98 percent while providing daily cycling capability.

To provide the maximum amount of operational and marketing flexibility, the combined cycle plant could be constructed in stages with the simple cycle combustion turbine being constructed first followed by the HRSG and steam turbine. Operational flexibility would be maximized with the addition of bypass dampers in the combustion turbine exhaust to allow operation of the combustion turbine in simple cycle mode.

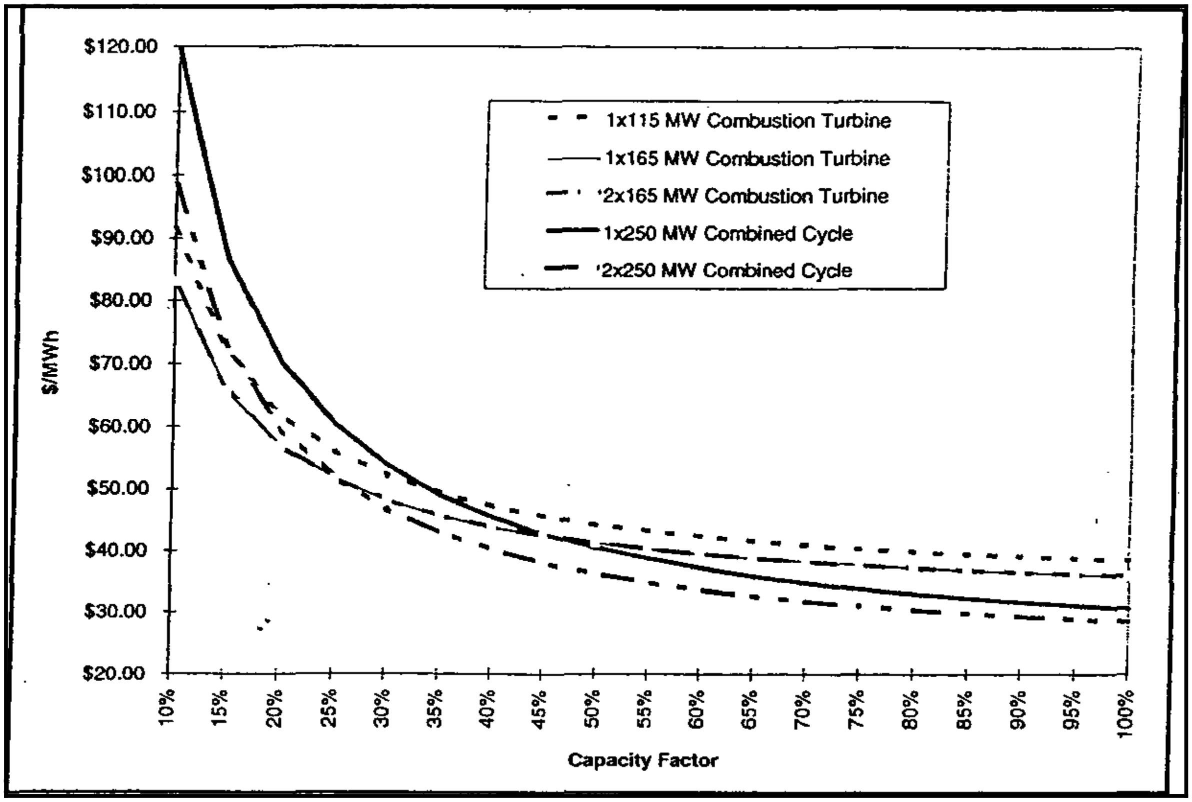
4.4 Resource Analysis

Analysis of the competitive potential of UCU owned supply resources involved the use of screening curves. Screening curves representing each technology option are placed on a common chart. Each option is represented by a line that gives the total "all in" production cost in $/MWh as a function of capacity factor. The intersection points where the cost of one option is equal to the cost of an alternative represent the capacity factor at which the options are equal in cost. At any given capacity factor, the option with the lowest cost will be represented by the lowest curve on the chart. The screening curves for the five UCU owned supply options are shown in Chart 4.4-1 on the following page.

These screening curves enable the comparison of costs for each resource across the range of capacity factors at which the resource can operate. This approach clearly demonstrates the least-cost resource options at various capacity factors; indicates the capacity factor range over which the alternative has the least costs and reveals if a resource is least cost at any capacity factor.

The information shown in Chart 4.4-1 was used to compare the total cost of the various resource types across the spectrum of annual capacity factors. As can be seen in Chart 4.4-1, the "2x250" combined cycle option has the lowest operating cost at annual load factors greater than 25%. This is due to economies of scale of large units and the efficiency advantage of combined cycle units when compared to simple cycle units.

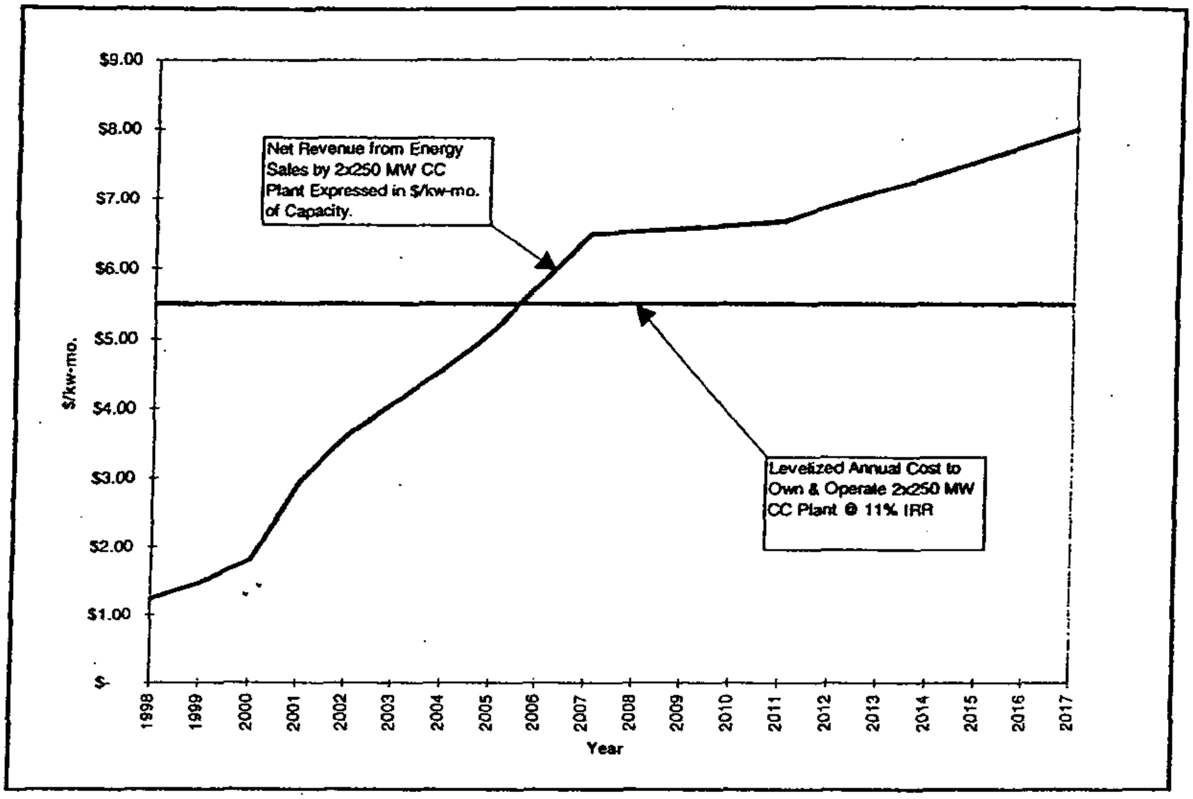
Chart 4.4-1: "All In" Production Cost vs. Load Factor
for five Supply Alternatives



To determine whether a large combined cycle unit would be able to compete in a deregulated marketplace, the annual ownership cost was compared to the annual revenue stream that could be expected from selling the energy output into the regional market at the projected market clearing price. Chart 4.4-2 compares the levelized annual ownership cost in $/kw-mo. of a 2x250 MW combined cycle unit to the annual revenue stream expressed as expected as a monthly capacity payment. As can be seen, the "2x250MW" unit becomes competitive in 2006.

Based on the analysis described here, UCU chose to evaluate the "2x250" MW combined cycle unit against the proposals received in response to the RFP issued on May 22, 1998.

Table 4.4-2: Levelized Ownership Cost vs. Energy Revenue



5. SUPPLY RESOURCE ANALYSIS

The analysis of the proposals received in response to the RFP issued on May 22, 1998 was conducted by Burns & McDonnell. Their preliminary report is attached as Appendix A.

Proposals were received from seven different firms. Only two of the proposals were for capacity and energy from existing resources. The remaining proposals were for capacity and energy from resources now under construction or from resources which would be constructed if the bidder was chosen in the evaluation process.

In summary, the results of the analysis indicate that UCU's proposal to construct a "2x250" MW combined cycle unit provides MPS the lowest cost energy supply. The total energy supply cost is strongly influenced by the incremental revenue resulting from off-system sales of energy produced by the proposed combined cycle unit.

Burns & McDonnell 100 1898 • 1998

August 21, 1998

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

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

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

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

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

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

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

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

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

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

Sincerely,

Daniel A. Froelich

Daniel A. Froelich, P.E.
Vice President

James M. Flucke

James M. Flucke, P.E.
Project Manager

Table 1
Assumptions Made for RealTime Modeling

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

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

Basin Electric Power Cooperative

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

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

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

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

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

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

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

Table 2 (Cont.)
Case 2 Description

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

Table 2 (Cont.)
Case 4 Description

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

Table 2 (Cont.)
Case 4b Description

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

Table 2 (Cont.)
Case 6 Description

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

Table 3

RealTime Modeling Results with Sales

June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,918						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Sales		-9,638,472	-$244,101,124						
Case 2					$ 56,009,906	-$229,989,146	$ 565,146,241	$ 391,167,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 146,501,561						
	Utilicorp Unit 2 (Online 2001)	250	4,741,587	$ 138,812,149						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199						
	SPS Option A (Parital Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,369						
	Sales		-8,294,721	-$229,989,146						
Case 3					$ 256,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,650						
	Southern	100	2,640,278	$ 59,698,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,732,666	$ 97,754,915						
	(Peaking Capacity)	25	11,069	$ 1,730,085						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,678	$ 35,079,240						
	Southern	100	2,035,607	$ 59,600,978						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	164	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,381,984
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,968,896						
	NP Energy	100	19,268	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Parital Requirement)	75	347,040	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,010						
Case 4b					$ 245,656,954	-$104,544,436	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	299,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,338						
	NP Energy	100	6,746	$ 18,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Parital Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,436						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,368,588						
	NP Energy	100	18,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,800	$ 18,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	166	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,934,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-5,553,100	-$140,445,134						

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

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-607
SUPPLEMENTAL RESPONSE

DATE OF REQUEST:	December 2, 2003
DATE RECEIVED:	December 2, 2003
DATE DUE:	December 22, 2003
REQUESTOR:	Cary Featherstone
BRIEF DESCRIPTION:	Support for the EWG Build Option

QUESTION:

With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.

RESPONSE:

1. Analyses relating to the need for additional power supply resources for Missouri Public Service was communicated to Staff and OPC through the following:
   Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
   Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998
2. Any notes taken at the referenced meeting are no longer available.
3. Any letters, e-mail, correspondence, and other communication are no longer available.

ATTACHMENT:
Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998

ANSWERED BY: Frank DeBacker

____
SIGNATURE OF RESPONDENT

Supplemental Response: See attached "Report on the Evaluation of Power Supply Proposals" dated 8/28/98. Missing page 2 was found and included in this complete copy of the report. Also included is the 2/1/99 update on "Report on the Evaluation of Power Supply Proposals".

Supplemental Attachments: Hard copy of "Report on the Evaluation of Power Supply Proposals" dated 8/21/98 and update to "Report on the Evaluation of Power Supply Proposals" dated 2/1/99.

Supplemental Response ANSWERED BY: Frank DeBacker

Burns & McDonnell 100 1898 • 1998

February 1, 1999

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

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

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

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

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

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

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

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

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

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

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

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

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

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

Houston Industries
Annual Ownership and Operating Cost
$x1,000

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

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

Burns & McDonnell 100 1898 • 1998

August 21, 1998

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

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

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

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

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

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

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

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

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

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

Sincerely,

Daniel A. Froelich

Daniel A. Froelich, P.E.
Vice President

James M. Flucke

James M. Flucke, P.E.
Project Manager

Table 1
Assumptions Made for RealTime Modeling

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

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

Basin Electric Power Cooperative

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

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

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

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

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

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

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

Table 2
Case 1 Description

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

Table 2 (Cont.)
Case 2 Description

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

Table 2 (Cont.)
Case 3 Description

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

Table 2 (Cont.)
Case 4 Description

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

Table 2 (Cont.)
Case 4a Description

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

Table 2 (Cont.)
Case 4b Description

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

Table 2 (Cont.)
Case 5 Description

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

Table 2 (Cont.)
Case 6 Description

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

Table 2 (Cont.)
Case 7 Description

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

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

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,418	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,818						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,626	$ 3,126,081						
	Sales		-8,638,472	-$244,101,124						
Case 2					$ 56,009,906	-$229,989,146	$ 565,146,241	$ 391,167,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 148,501,561						
	Utilicorp Unit 2 (Online 2001)	250	4,741,547	$ 136,812,149						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,389						
	Sales		-9,294,721	-$229,989,146						
Case 3					$ 258,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,850						
	Southern	100	2,040,278	$ 59,698,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,732,666	$ 97,758,915						
	(Peaking Capacity)	25	11,069	$ 1,730,065						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,670	$ 35,079,240						
	Southern	100	2,035,607	$ 59,600,970						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,381,984
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,968,898						
	NP Energy	100	19,268	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Partial Requirement)	75	347,040	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,010						
Case 4b					$ 245,656,954	-$104,544,438	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	269,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,336						
	NP Energy	100	6,746	$ 18,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,626	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,438						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,364,566						
	NP Energy	100	16,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	166	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,800	$ 18,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,938,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-5,553,100	-$140,445,134						

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

Table 4

RealTime Modeling Results without Sales

June 1, 2000 to May 31, 2004

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

Notes

SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years

SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b

Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

SCHEDULES 2 THROUGH 8

ARE

DEEMED

HIGHLY CONFIDENTIAL

Non-Proprietary

Greenwood Power Plant

Analysis

Greenwood Power Plant
units one and two
Comparasion of purchase versus lease costs to ratepayers

	Dates	Lease Payments	Depreciation Rate	Annual Depreciation	Accumulated Depreciation	Net Plant Book Value @ 12/31	Rate of Return	Rate Base Portion of Revenue Requirement	Revenue Requirement (Rate Base plus Depreciation)	Revenue Requirement Plus Depreciation Minus Lease Payments
	original cost $11,482,874									
	Plant values at inception		0.03636	$ -	-	$ 11,482,874.00				
1	June 1, 1975 - December 31, 1975	$ 553,130	0.03636	$ 243,552	$ 243,552	$ 11,239,322	10.5450%	$ 691,359	$ 934,911	$ 381,780.52
2	January 1, 1976 - December 31, 1976	$ 1,106,260	0.03636	$ 417,517	$ 661,069	$ 10,821,805	10.5450%	$ 1,141,159	$ 1,558,677	$ 452,416.51
3	January 1, 1977 - December 31, 1977	$ 1,106,260	0.03636	$ 417,517	$ 1,078,586	$ 10,404,288	10.5450%	$ 1,097,132	$ 1,514,649	$ 408,389.31
4	January 1, 1978 - December 31, 1978	$ 1,106,260	0.03636	$ 417,517	$ 1,496,104	$ 9,986,770	12.2578%	$ 1,224,158	$ 1,641,676	$ 535,415.51
5	January 1, 1979- December 31, 1979	$ 1,106,260	0.03636	$ 417,517	$ 1,913,621	$ 9,569,253	12.4622%	$ 1,192,539	$ 1,610,057	$ 503,796.83
6	January 1, 1980 - December 31, 1980	$ 1,106,260	0.03636	$ 417,517	$ 2,331,138	$ 9,151,736	12.7066%	$ 1,162,874	$ 1,580,392	$ 474,131.83
7	January 1, 1981 - December 31, 1981	$ 1,106,260	0.03636	$ 417,517	$ 2,748,656	$ 8,734,218	12.7066%	$ 1,109,822	$ 1,527,340	$ 421,079.38
8	January 1, 1982 - December 31, 1982	$ 1,106,260	0.03636	$ 417,517	$ 3,166,173	$ 8,316,701	14.5124%	$ 1,206,953	$ 1,624,470	$ 518,210.12
9	January 1, 1983 - December 31, 1983	$ 1,106,260	0.03636	$ 417,517	$ 3,583,690	$ 7,899,184	15.2414%	$ 1,203,946	$ 1,621,464	$ 515,203.39
10	January 1, 1984 - December 31, 1984	$ 1,106,260	0.03636	$ 417,517	$ 4,001,207	$ 7,481,667	15.2414%	$ 1,140,311	$ 1,557,828	$ 451,567.90
11	January 1, 1985 - December 31, 1985	$ 1,106,260	0.03636	$ 417,517	$ 4,418,725	$ 7,064,149	15.2414%	$ 1,076,675	$ 1,494,193	$ 387,932.42
12	January 1, 1986 - December 31, 1986	$ 1,106,260	0.03636	$ 417,517	$ 4,836,242	$ 6,646,632	15.2414%	$ 1,013,040	$ 1,430,557	$ 324,296.94
13	January 1, 1987 - December 31, 1987	$ 1,106,260	0.03636	$ 417,517	$ 5,253,759	$ 6,229,115	15.2414%	$ 949,404	$ 1,366,922	$ 260,661.46
14	January 1, 1988 - December 31, 1988	$ 1,106,260	0.03636	$ 417,517	$ 5,671,277	$ 5,811,597	15.2414%	$ 885,769	$ 1,303,286	$ 197,025.98
15	January 1, 1989 - December 31, 1989	$ 1,106,260	0.03636	$ 417,517	$ 6,088,794	$ 5,394,080	15.2414%	$ 822,133	$ 1,239,651	$ 133,390.50
16	January 1, 1990 - December 31, 1990	$ 1,106,260	0.03636	$ 417,517	$ 6,506,311	$ 4,976,563	14.8936%	$ 741,189	$ 1,158,707	$ 52,446.53
17	January 1, 1991 - December 31, 1991	$ 1,106,260	0.03636	$ 417,517	$ 6,923,829	$ 4,559,045	14.8936%	$ 679,006	$ 1,096,523	$ (9,736.83)
18	January 1, 1992 - December 31, 1992	$ 1,106,260	0.03636	$ 417,517	$ 7,341,346	$ 4,141,528	14.8936%	$ 616,823	$ 1,034,340	$ (71,920.18)
19	January 1, 1993 - December 31, 1993	$ 1,106,260	0.03636	$ 417,517	$ 7,758,863	$ 3,724,011	14.8936%	$ 554,639	$ 972,157	$ (134,103.54)
20	January 1, 1994 - December 31, 1994	$ 1,106,260	0.03636	$ 417,517	$ 8,176,380	$ 3,306,494	14.8936%	$ 492,456	$ 909,973	$ (196,286.90)
21	January 1, 1995 - December 31, 1995	$ 1,106,260	0.03636	$ 417,517	$ 8,593,898	$ 2,888,976	14.8936%	$ 430,273	$ 847,790	$ (258,470.25)
22	January 1, 1996 - December 31, 1996	$ 1,106,260	0.03636	$ 417,517	$ 9,011,415	$ 2,471,459	14.8936%	$ 368,089	$ 785,607	$ (320,653.61)
23	January 1, 1997 - December 31, 1997	$ 1,106,260	0.03636	$ 417,517	$ 9,428,932	$ 2,053,942	14.8936%	$ 305,906	$ 723,423	$ (382,836.97)
24	January 1, 1998 - December 31, 1998	$ 1,106,260	0.03636	$ 417,517	$ 9,846,450	$ 1,636,424	12.0446%	$ 197,101	$ 614,618	$ (491,642.05)
25	January 1, 1999 - December 31, 1999	$ 1,106,260	0.03636	$ 417,517	$ 10,263,967	$ 1,218,907	12.0446%	$ 146,812	$ 564,330	$ (541,930.34)
26	January 1, 2000 - May 31, 2000	$ 460,942	0.03636	$ 173,966	$ 10,437,933	$ 1,044,942	12.0446%	$ 52,441	$ 226,407	$ (234,534.92)
		$ 27,564,315		$ 10,437,933				$ 20,502,011	$ 30,939,944	$ 3,375,629.14
	Second lease first five years									
27	June 1, 2000 - December 31, 2000	$ 1,824,640	0.03636	$ 243,552	$ 10,681,484	$ 801,390	12.0446%	$ 56,306	$ 299,858	$ (1,524,782.44)
28	January 1, 2001 - December 31, 2001	$ 3,051,641	0.03636	$ 417,517	$ 11,099,002	$ 383,872	12.0446%	$ 46,236	$ 463,753	$ (2,587,888.19)
29	January 1, 2002 - December 31, 2002	$ 2,920,819	0.03636	$ 417,517	$ 11,516,519	$ (33,645)	12.0446%	$ (4,052)	$ 413,465	$ (2,507,354.68)
30	January 1, 2003 - December 31, 2003	$ 2,789,997	0.03636	$ 417,517	$ 11,934,036	$ (451,162)	12.0446%	$ (54,341)	$ 363,176	$ (2,426,820.88)
31	January 1, 2004 - December 31, 2004	$ 2,659,175	0.03636	$ 417,517	$ 12,351,553	$ (868,679)	12.0446%	$ (104,629)	$ 312,888	$ (2,346,287.09)
32	January 1, 2005 - May 31, 2005	$ 1,085,278	0.03636	$ 417,517	$ 12,769,070	$ (1,286,196)	12.0446%	$ (154,917)	$ 262,600	$ (822,677.63)
		$ 14,331,551		$ 2,331,137				$ (215,397)	$ 2,115,740	$ (12,215,810.91)
	Second lease second five years									
33	June 1, 2005 - December 31, 2005	$ 1,443,076		$ 417,517	$ 13,186,587	$ (1,703,713)	12.0446%	$ (205,205)	$ 212,312	$ (1,230,764.02)
34	January 1, 2006 - December 31, 2006	$ 2,419,335		$ 417,517	$ 13,604,104	$ (2,121,230)	12.0446%	$ (255,494)	$ 162,023	$ (2,257,311.41)
35	January 1, 2007 - December 31, 2007	$ 2,266,709		$ 417,517	$ 14,021,621	$ (2,538,747)	12.0446%	$ (305,782)	$ 111,735	$ (2,154,973.94)
36	January 1, 2008 - December 31, 2008	$ 2,135,887		$ 417,517	$ 14,439,138	$ (2,956,264)	12.0446%	$ (356,070)	$ 61,447	$ (2,074,440.14)
37	January 1, 2009 - December 31, 2009	$ 2,005,065		$ 417,517	$ 14,856,655	$ (3,373,781)	12.0446%	$ (406,358)	$ 11,159	$ (1,993,906.33)
38	January 1, 2010- May 31, 2010	$ 812,732		$ 417,517	$ 15,274,172	$ (3,791,298)	12.0446%	$ (456,647)	$ (39,130)	$ (851,861.20)
		$ 11,082,803		$ 2,505,102				$ (1,985,556)	$ 519,546	$ (10,563,257.04)
	Second lease third five years									
39	June 1, 2010 - December 31, 2010	$ 758,222		$ 417,517	$ 15,691,689	$ (4,208,815)	12.0446%	$ (506,935)	$ (89,418)	$ (847,640.26)
40	January 1, 2011 - December 31, 2011	$ 1,743,421		$ 417,517	$ 16,109,206	$ (4,626,332)	12.0446%	$ (557,223)	$ (139,706)	$ (1,883,126.99)
41	January 1, 2012 - December 31, 2012	$ 1,612,599		$ 417,517	$ 16,526,723	$ (5,043,849)	12.0446%	$ (607,511)	$ (189,994)	$ (1,802,593.19)
42	January 1, 2013 - December 31, 2013	$ 1,481,777		$ 417,517	$ 16,944,240	$ (5,461,366)	12.0446%	$ (657,800)	$ (240,283)	$ (1,722,059.39)
43	January 1, 2014 - December 31, 2014	$ 1,350,955		$ 417,517	$ 17,361,757	$ (5,878,883)	12.0446%	$ (708,088)	$ (290,571)	$ (1,641,525.59)
44	January 1, 2015 - May 31, 2015	$ 540,186		$ 417,517	$ 17,779,274	$ (6,296,400)	12.0446%	$ (758,376)	$ (340,859)	$ (881,044.77)
	Totals	$ 7,487,159		$ 2,505,102				$ (3,795,933)	$ (1,290,831)	$ (8,777,990)
				$ -	$ -			$ -	$ -	-
	Grand Lease Total	$ 60,465,828		$ 17,779,274	$ 17,779,274			$ 14,505,125	$ 32,284,399	$ (28,181,429.00)
	Grand Rate-Base Total	$ 32,284,399								
	Difference	$ 28,181,429								

Schedule 9-2