Exhibit No.:	
Issue:	Generation
Witness:	Robert W. Holzwarth
Type of Exhibit:	Direct Testimony
Sponsoring Party:	UtiliCorp United Inc.
Case No.:	

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Robert W. Holzwarth

December 1999

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF ROBERT W. HOLZWARTH
ON BEHALF OF UTILICORP UNITED INC.

CASE NO.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert W. Holzwarth and my business address is 10750 East 350 Highway, Kansas City, Missouri 64138.

Q. By whom are you employed and in what capacity?

A. I am employed by UtiliCorp United Inc. ("UtiliCorp") as Vice President & General Manager, Energy Supply Services in its domestic regulated electric utility operations.

Q. Please describe your responsibilities in that position.

A. Within its domestic regulated electric utility operations, UtiliCorp has functionally separated the supply of electric energy from the transmission and distribution of that energy. I am employed within the energy supply operation. My major responsibility is management of UtiliCorp's regulated generation and generation support functions, i.e., purchase power, generation dispatch, energy trading and wholesale customer service.

Q. What are your educational qualifications, training, and experience?

A. I hold a Bachelor of Science Degree in Technical Management from Denver Technical College and have twenty eight years of experience in utility operations. I began my electric utility career in 1971 with The Montana Power Company of Butte, Montana.. In 1976, I joined Basin Electric Power Cooperative as plant superintendent followed by plant manager. In 1986, I joined Colorado Springs Department of Utilities as a operations manager, followed by two years with Ralph Parsons Company managing the Saudi Arabian Royal Commission's modern electric and water utilities. In 1993, I joined UtiliCorp as director of power production at the WestPlains Energy unit in Pueblo, Colorado, followed by vice president, generation managing the Colorado, Kansas and Missouri generating stations. Since 1997, I have been in my present role.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of UtiliCorp, its Missouri Public Service ("MPS") operating division.

Q. Was the analysis described in your testimony prepared by you or under your direction and supervision?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony will describe the operational and financial impact of jointly planning and operating the electric power supply systems of MPS and Empire. Upon completion of the merger, UtiliCorp intends to consolidate what are now two separate electric supply functions in Missouri into one integrated control area. This consolidation will result in a reduction in operating costs of up to $180.8 million over the ten-year period 2001-2010. It will also reduce fuel and operating risk. The purpose of this testimony is to describe how these conclusions were reached.

Q. Please explain the structure of your testimony.

A. My testimony is divided into five main topics and a short conclusion. The main areas covered by my testimony are as follows:

Joint Planning and Dispatch Synergies
Human Resource & Other Synergies
Synergy Sharing Methodology
Current vs. Original Synergy Analysis
Impact of the St. Joseph Light & Power Merger

JOINT PLANNING & DISPATCH

Electric Operations of the Joint Applications Before and After the Merger

Q. Please describe the electric operations of the two companies.

A. Empire's electric operations are located in southwest Missouri while the MPS electric operations are located primarily adjacent to the Kansas City metro area. Schedule RWH-1, page 1 shows the electric service territories and generation resources of UtiliCorp which are located in Missouri, Kansas and Colorado. Schedule RWH-1, page 2 shows the electric service territories of MPS and Empire as well as the location of their respective generation resources.

Q. Please provide an overview of the present power supply portfolios of the two companies.

A. During the evaluation period, MPS will own and/or lease 1,053 megawatts of generation capacity. Of this amount 677 megawatts is classified as base load capacity and 376 megawatts is classified as peaking capacity. Empire currently owns 878 megawatts of generation capacity and is in the process of expanding its generation asset base by 148 MW by expanding its State Line generating facility. Of the 1,026 megawatts (878 + 148) owned by Empire, 384 megawatts is classified as base load capacity and 642 megawatts is classified as intermediate/peaking capacity. In addition to their generating capacity, both companies will purchase capacity and energy from other parties through existing contracts. MPS will purchase approximately 375 megawatts of capacity in 2001 and 500 megawatts in the years 2002 - 2004. Empire will purchase 162 megawatts in the years 2001 - 2009. Schedule RWH-2 lists the 1998 capacity, fuel type, and the year installed for each power plant and the current purchase power contract capacities for both companies.

Q. What is a "control area"?

A. Briefly, a control area is the area covered by the day-to-day operation of an electric utility's transmission and distribution system within which the utility balances or matches the supply and demand for energy on a continuous basis. The utility also coordinates the operation of its control area with the operations of other utility control areas with which it is directly or indirectly interconnected.

Q. Please expand on how supply is matched to demand.

A. Both companies follow principles of economic dispatch in matching supply and demand. Economic dispatch is the continuous, real-time decision-making function in which the system operator, given the actual mix of generating units and power purchase/sell opportunities, meets current customer demands at the lowest variable cost while, at the same time, meeting the North America Electric Reliability Council ("NERC") reliability requirements, emission restrictions, and the terms of customer and inter-utility contracts.

Q. Are there other considerations in matching supply and demand?

A. Yes. In determining which resources to dispatch to serve load, a utility also considers several additional factors with respect to individual power plants. These include: forced and scheduled outages, minimum and maximum loadings, ramp rates, start-up costs, and cycle times (minimum run times and minimum off-line times) for the various generating facilities. Additional considerations include the provision of voltage support, load-following, operating reserves, and other ancillary services.

Q. Please describe how the combined systems will be operated after the merger.

A. UtiliCorp intends to integrate the MPS and Empire control areas and consolidate the power supply functions of the two companies into one operating unit.

Q. What will result from combining the power supply functions of the two companies?

A. There are four principle benefits that result from the consolidation of the power supply functions of the two companies into one unit:

1. Resource Diversity:
   Each system has a single, large resource. For MPS, the Sibley 3 unit represents approximately 28% of both its capacity and its energy resources. For Empire, its share of the State Line Combined Cycle ("SLCC") unit represents approximately 29% of its capacity resources and approximately 24% of its energy resources. For the combined system, the Sibley 3 unit represents 19% of the capacity and 17% of the energy resources while the SLCC share represents approximately 14% of the capacity and 13% of the energy resources. The reduced reliance on a single generating unit reduces the probability of the necessity of purchasing replacement energy at market based prices in the event of an outage of that unit.
2. Market Access:
   As can be seen from the following table, the combined system will have a wider access to the power markets than either company has on an individual basis. As will be discussed in Section I, this access to a wider market area will contribute to

a lowering of overall energy supply costs by increasing the opportunity to increase the sale of excess energy.

MPS & Empire Transmission Interconnects

Empire Interconnects		MPS Interconnects		NWCO Interconnects	
Company	Reliability Council	Company	Reliability Council	Company	Reliability Council
WRI	SPP	WRI	SPP	WRI	SPP
KCPL	SPP	KCPL	SPP	KCPL	SPP
CSW	SPP	AECI	SERC	CSW	SPP
SWPA	SPP	Ameren	MAIN	SWPA	SPP
GRDA	SPP			GRDA	SPP
Entergy	SERC			AECI	SERC
AECI	SERC			Entergy	SERC
SJLP	MAPP			Ameren	MAIN
				SJLP	MAPP

3. Lower Generation Cost:
   Joint dispatching of the combined supply resources will reduce the total energy cost to the combined system by increasing the amount of energy supplied by the low cost energy resources and reducing the amount of energy supplied by higher cost energy resources.
4. Reduced Capacity Cost:
   Combining the loads of the two systems into a single control area reduces the amount of capacity required due to the natural diversity between the load profiles of the two systems. This reduction in the amount of required capacity reduces the overall power supply cost to the combined system.

Q. How will the two control systems be consolidated into one control area?

A. The two control areas will be connected with a firm transmission path by either the construction of a transmission line between the two systems or by the securing of firm transmission services from a third party. In addition, communication facilities will be acquired which will provide the necessary telemetry of critical operating parameters from the Empire system to the present MPS operations center.

Q. When will the two control areas be consolidated into one control area?

A. As soon as possible, but no later than one year after closing.

Q. Can any of the savings outlined above be achieved without combining the two power supply functions into a single power supply function and jointly dispatching the power supply resources of the two systems?

A. The vast majority of the benefits associated with resource diversity, reduced capacity requirements, lower power supply costs and market access cannot be achieved without fully integrating the two systems. While it may be possible to achieve a portion of the energy cost reductions through the use of day ahead schedules, the ability to take advantage of intra day opportunities to reduce energy supply cost would be minimal due to the intervening control areas of other entities. In addition, to take full advantage of resource diversity and reduction in capacity requirements, generating units must lie within a common control area.

Q. It has been announced that both Mid-Continent Area Power Pool ("MAPP) and the Southwest Power Pool ("SPP") are in discussions with the Midwest Independent System Operator ("ISO") concerning the feasibility of MAPP and the SPP joining the Midwest ISO. What will be the impact if MAPP and the SPP join the Midwest ISO?

A. Several benefits would result from such an event:

1. The operation and control of the transmission system would under the direction of an independent entity. This would prevent gaming of the transmission system and give equal access to all market participants.

2. If a regional tariff is part of the ISO, the combined company could see a cost reduction if the cost of the tariff is less than the cost of constructing a transmission interconnect between MPS and Empire.
3. A large ISO would extend the transmission reach of the company giving it increased market access and thus potentially lower its cost for off system purchases and increase its margin for off system sales.

Method of Analysis

Q. Please explain how the benefits of combining the power supply function of the two companies were determined.

A. The following steps were used to determined the benefits of combining the power supply function of the two companies:

1. Estimate the future market energy price.
2. Determine optimum power supply plan for each system on a stand alone basis.
3. Determine feasible operating enhancements for the Empire generating units.
4. Determine the optimum power supply plan for the combined system.
5. Compare the annual cost of the combined systems to the sum of the annual cost of the two systems on a stand alone basis.

Q. Please describe the production costing model used to quantify the potential benefits of jointly dispatching the combined system.

A. MPS uses the RealTime® production costing software from the Emelar Group. RealTime® operates in a chronological fashion, solving each hour's demands before moving to the next hour, closely simulating the way a utility operates its power supply portfolio. RealTime® solves each hour's demand based upon many factors. It schedules units and contracts economically based upon fuel cost, start up cost, emission cost, O&M cost and available contract energy.

The chronological nature of RealTime® enables the software to provide detailed hourly status reports for the system being analyzed. Output information includes production amounts, fuel costs, total costs, marginal costs, average system costs, emissions, etc. for each power supply resource included in the model. RealTime® is very useful for the evaluation of the economies of varied power supply resource plans.

RealTime's output can be printed, written to spreadsheet files, graphed and saved in order to create difference reports for various scenarios being analyzed.

Q. How was the future market energy price estimated?

A. The estimate of the future market energy price was developed from data provided by the firm of Hill & Associates, Inc. ("Hill & Associates"). This firm annually publishes a report which contains a fifteen year forecast of marginal production costs by time of day and season of the year for all areas of the United States. One aspect of the report was particularly useful. The report contains projections of the future market clearing energy prices for the northern region of the SPP sub region of the SPP reliability council. The forecast of marginal production costs by time of day and season of the year is contained in Schedule RWH-3. This forecast was the basis for projecting the cost of energy purchased in the market as well as revenue from energy sold in the market. These projections were used in the analysis which produced the forecast of future power supply cost of UtiliCorp and Empire on a stand alone and combined basis (Steps 2 & 4 above).

Q. Who is Hill & Associates?

A. Hill & Associates, Inc. is a management consulting firm that provides analyses of coal and electricity markets and consulting services to the management of companies serving those markets. Its strength lies in its combination of extensive proprietary data on supply, demand and transportation; the use of analytical tools developed to provide realistic market analysis; and a staff with broad experience in the industry and in consulting. Clients include electric utilities, coal producers, banks, oil companies, law firms, railroads and terminal operators throughout the world.

Q. How were forecasts for the cost of UtiliCorp's and Empire's power supply plans under the stand alone scenario determined?

A. First, capacity expansion plans were developed for both UtiliCorp and Empire assuming that each would remain a separate utility throughout the study period. The study or evaluation period used was the ten year period, 2001 - 2010.

Q. Why did you choose the time period 2001 - 2010?

A. This is consistent with the testimony of the other witnesses and based on the assumption the merger closes in the first half of 2000.

Q. Please describe the Empire expansion plan.

As noted above, Empire has entered into a long term purchase power agreement for 162 MW and embarked on a project to increase its generating capacity by 148 MW. These two resources will enable it to meet the majority of its capacity and energy needs through all years of the study period except 2010. For the years 2001 - 2009, Empire's expansion plan consists of incremental peaking purchases. For 2010, two options for incremental power supply were considered. The first is based on a 250 MW combined cycle unit using a "F" technology combustion turbine in a 1x1 configuration. The second option is based on two, 160 MW "F" technology combustion turbines. The two expansion plans for Empire are contained in Schedule RWH-4, page 1. As indicated the future, incremental capacity requirements for Empire are as follows:

Empire Stand Alone Capacity Additions in MW

	Combined Cycle Plan			Combustion Turbine Plan		
Year	CT	CC	PPA	CT	CC	PPA
2001						
2002						
2003						
2004						
2005			5			5
2006			20			20
2007			40			40
2008			60			60
2009			75			75
2010		250	5	320		

Q. Please describe the MPS expansion plans.

A. Two expansion plans were developed for MPS as a stand alone entity. In the first expansion plan all new capacity was assumed to come from simple cycle combustion turbines using "F" technology turbines (160 MW output). In the second expansion plan a significant portion of new capacity was assumed to be based on combined cycle generation using two "F" technology turbines in a 2x1 configuration (500 MW output).

Q. How were the annual ownership costs for capacity options determined?

A. Based on the current capital costs of $300/kw for a 160 MW simple cycle peaking unit and $450/kw for a 500 MW combined cycle unit, annual ownership costs were developed for each expansion option. Schedule RWH-5 shows how these costs were developed.

Q. You previously mentioned that the cost of short term purchases for Empire would be priced at the then current cost of new peaking capacity. Is this true for all short term purchases for both Empire and MPS?

A. Yes.

Q. Please describe the timing and amount of incremental capacity additions for the two MPS expansion plans?

A. Forecasts of resource additions for both expansion plans are shown in Schedule RWH-4, pages 2 & 3. As indicated the future capacity requirements for MPS under the combined cycle and combustion turbine expansion plans are as follows:

MPS Stand Alone Capacity Additions in MW

	Combined Cycle Plan			Combustion Turbine Plan		
Year	CT	CC	PPA	CT	CC	PPA
2001						
2002						
2003						
2004			10			10
2005		500	60	480		80
2006	160	500		640		
2007	160	500	5	640		25
2008	160	500	60	640		80
2009	320	500		800		
2010	320	500	10	800		30

Note that a total of two 160 MW combustion turbines and one 500 MW combined cycle unit are added in the combined cycle expansion plan and five 160 MW combustion turbines are added in the combustion turbine expansion plan.

Q. How were the stand alone power supply cost determined for MPS and Empire?

A. After the stand alone expansion plans were developed, the power supply cost for each expansion plan was determined. The energy costs were determined through the use of the RealTime® production costing model using the following basic assumptions:

1. Current, committed supply portfolios of each entity without changes.
2. Expansion plans outlined above
3. Current fuel and O&M costs

Finally, the annual costs of the incremental capacity resources were combined with the energy cost forecast from the RealTime® model to determine the annual supply cost in each case.

Q. What is the projected energy and incremental capacity cost for each of the stand alone cases?

A. Results for each of the above expansion plans showing annual power supply costs are contained in Schedule RWH-6. As indicated the stand alone cases result in a total ten year power supply cost of the following:

10 Year Stand Alone Power Supply Cost

Case Description	Total 10 Year Cost ($x1,000)	NPV of 10 Year Cost ($x1,000)
MPS - CC Expansion	$1,458,147	$815,551
MPS - CT Expansion	1,517,995	845,291
Empire - CC Expansion	1,004,465	579,864
Empire - CT Expansion	1,000,577	578,313

As can be seen, the lower cost combined cycle expansion plan is the preferred plan for the MPS stand alone case. However, the CT expansion plan is the preferred plan for the Empire stand alone case.

Q. How were the cost forecasts for UtiliCorp's and Empire's power supply under the combined systems scenario determined?

A. First, the individual hourly load profiles of the two systems were combined into a single load profile. This single system load profile was combined with the consolidated, committed resource portfolios from both systems. Two system load and resource forecasts were developed for the consolidated system. The incremental resource additions in the first forecast were limited to short term purchases and combustion turbine peaking units (160 MW output), while the second forecast included combined cycle generation resources (500 MW output). Incremental resource additions for both combined system expansion plans are shown in Schedule RWH-4, pages 4 & 5, and summarized below:

Combined System Capacity Additions in MW

	Combined Cycle Plan			Combustion Turbine Plan		
Year	CT	CC	PPA	CT	CC	PPA
2001						
2002						
2003						
2004						
2005		500	40	480		60
2006	160	500		640		
2007	160	500	25	640		45
2008	320	500		800		
2009	320	500	10	800		30
2010	320	750		1120		

Second, the feasible operating enhancements for the Empire generating units were determined. These enhancements focused on the heat rate of the Asbury unit #1. An overview of these operating cost enhancements is contained in Schedule RWH-7.

In addition, the power supply cost for each of the combined system expansion plans were determined. The energy costs were determined through the use of the RealTime® production costing model using the following basic assumptions:

1. Current, committed supply portfolios of each entity without changes.
2. Combined system expansion plans outlined above
3. Current fuel and O&M costs to the MPS generation resources
4. Modify the Empire fuel and O&M costs outlined above

Finally, the annual costs of the incremental capacity resources were combined with the output from the RealTime® model to determine the annual supply cost for each scenario. Results for each of the above expansion plans showing annual costs are contained in Schedule RWH-8.

Q. Please describe the model used to quantify the potential benefits of jointly dispatching the combined systems.

A. The same production costing software used in the stand alone cases was used to analyze the combined cases. The evaluation period was the ten-year period from 2000-2010.

Q. What is the reserve margin criterion used in planning for the combined company?

A. As members of the SPP, the capacity reserve planning margin for both MPS is 12.0%.

Q. What is the projected energy and incremental capacity cost for each of the combined system cases?

A. As mentioned previously, results for each of the two combined system expansion plans showing annual costs are contained in Schedule RWH-8. As indicated, the total ten year cost for each expansion plan for the combined system is as follows:

Combined System Total 10 Year Power Supply Cost

Case Description	Total 10 Year Cost ($x1,000)	NPV of 10 Year Cost ($x1,000)
CC Expansion	$2,289,633	$1,295,329
CT Expansion	2,391,726	1,346,028

As indicated above, the lower cost combined cycle expansion plan is the preferred expansion plan for the combined MPS/Empire system.

Results of Analysis

Q. Based on the above analysis what is the forecast of power supply savings for the combined systems over the ten year study period?

A. The total power supply savings over the ten year study period for each expansion plan are shown below:

MPS/Empire Merger Power Supply Savings

	($ x 1,000)
Empire Stand Alone	1,000,577
MPS Stand Alone	1,458,148
Total Stand Alone Systems	2,458,725
Total Combined System	2,289,633
Net Power Supply Savings	169,092

Q. Please summarize the key points of your testimony thus far.

A. As a result of the merger, the new company will be in a position to make more efficient use of the lower cost power resources. It can reduce the amount of energy supplied from the higher cost power plants and purchase power contracts. In addition, the expanded generation base of the combined system will be more competitive in the wholesale markets and increase the market share and margins from opportunity sales in the wholesale market. Finally, the financial risk from an unplanned outage of a single large resource (Sibley or SLCC) will be reduced due to the larger resource base of the combined system.

HUMAN RESOURCE & OTHER SYNERGIES

Q. How will the energy supply function of the combined company be organized?

A. Current plans call for the Empire energy supply function to be absorbed into the existing UtiliCorp organization. The headquarters for the administration, engineering and power dispatch functions will be at the UtiliCorp's present offices in Raytown, MO.

Q. Will there be any staff reductions?

A. Yes. Current plans show that the elimination of duplicate function will reduce the number of employees by a total of fourteen when compared to the sum of the positions in the two separate power supply functions.

Q. What is the level of annual salaries that are being eliminated.

A. The reduction in annual salary cost is approximately $942,000 (1999 $).

Q. What is the total ten year cost reduction which results from the above reduction in staff?

A. The total ten year cost reduction in actual dollars is approximately $11 million. Details of the calculation of this value can be found in Schedule RWH-9.

Q. Have any other synergies been determined?

A. Yes. Approximately $50,000 (1999$) per year in savings will result from the elimination of duplicate software licenses with an estimated total ten year cost reduction of approximately $589,000.

SYNERGY SHARING METHODOLOGY

Q. How does UtiliCorp propose to allocate the above synergies between MPS and Empire?

A. For power supply synergies, UtiliCorp plans to employ a synergy sharing plan patterned on the Allocation Agreement proposed by Missouri Public Service Commission ("Commission") Staff witness James C. Watkins in Commission Case No. EM-97-515. The proposed plan is contained in Schedule RWH-10.

Q. What are the main elements of the proposed synergy sharing plan?

A. The main elements of the proposed synergy sharing plan are as follows:

1. Existing generation capacity costs and purchased power capacity costs will remain with the entity which owned or had contracted for such capacity prior to the closing of the merger.
2. New generation and/or purchased capacity and associated cost will be assigned to each entity on the basis of the capacity needs of each entity. The assignment will be on an equal cost per kilowatt basis.
3. The power supply portfolio of the combined entity will be dispatched in a manner to minimize the overall power supply cost of the combined system. Energy savings achieved will be allocated to Empire since none of the savings would be possible absent the merger.

Q. How will on-system energy savings be determined?

A. The RealTime® production costing model will be used to simulate monthly fuel and purchased power energy costs incurred to serve the native load of the combined system. The model will be calibrated to duplicate the actual performance of the combined power supply portfolio in the subject month.

Once the model is calibrated, the MPS and Empire systems will be modeled on a "stand alone" basis to determine the power supply costs of the respective entity. The difference in power supply costs between the "stand alone" models and the combined system model will be the energy cost savings for the respective month.

Q. How will the margins from off system sales be determined and assigned?

A. Records of off system sales will be maintained in a manner which will allow each sale to be assigned to a power supply resource (i.e., : generating unit, purchase power contract, etc.). The margins from off system sales to be assigned to Empire since none of the additional margins would have occurred absent the merger.

Q. How will human resource cost savings be shared?

A. Human resource cost savings will flow to Empire since all of the personnel reductions occur at Empire.

Q. Base on the above, what is the value of the projected synergies for both MPS and Empire?

A. Schedule RWH-9 shows the human resource synergies and Schedule RWH-11 shows the allocation of power supply synergies based on the plan outlined above. As indicated, the ten year merger synergies for both MPS and Empire are as follows:

10 Year Synergy Allocation - $ x 1,000

Synergy	MPS	Empire	Total
Capacity Cost	6,436	6,436	12,872
On-System Energy	0	39,802	39,802
Off System Sales	0	116,417	116,417
Sub-Total	6,436	162,656	169,092
Human Resources	0	11,086	11,086
Other	0	589	589
Total	6,436	174,331	180,767

CURRENT vs. ORIGINAL SYNERGY ANALYSIS

Q. Have there been any significant changes to the value of the projected synergies resulting from jointly planning and operating the electric power supply systems of MPS and Empire?

A. Yes. Several changes in the analysis have occurred since the original synergy analysis was accomplished. Each of these changes has negatively affected the value of the projected synergies. These changes decreased the total value of the power supply synergies available to MPS and Empire by approximately $159.8 million. Supporting data for these calculations are contained in Schedule RWH-12. The more significant changes and their 10 year financial impact are shown below.

Significant Changes in Synergy Analysis

Category	Original	Current	Change
Capacity Diversity Savings	103,121	12,872	(90,249)
On System Energy Savings	165,449	39,802	(125,647)
Off System Sales Margins	60,324	116,417	56,093
Total	328,894	169,091	(159,803)

Q. Please briefly explain each of the above changes.

A. Capacity diversity savings decreased due to the fact that the original analysis assumed that the peak demand of the combined system was approximately 20 megawatts less than the arithmetic sum of the peak demands of the two separate systems. This diversity was actually only 4 megawatts. The 16 megawatt change in capacity diversity reduced the amount of capacity savings.

On system energy savings decreased due to the fact that the original analysis overstated the stand alone, on system energy costs for Empire. Based on Empire's budget projections, the original stand alone Empire analysis assumed that Empire was not active in the economy energy market. Subsequent investigation revealed that this was not the case and the assumption was changed. This change reduced the energy cost of the Empire stand alone analysis and thus reduced the on system energy savings resulting from combining the two systems.

Off system sales margins were projected conservatively in the original analysis. The current analysis represents a more aggressive off system sales projection reflecting the evolving and expanding wholesale power markets in the Midwest.

IMPACT OF THE St. JOSEPH LIGHT & POWER MERGER

Q. Is there an impact on the Empire transaction from the proposed UtiliCorp merger with St. Joseph Light & Power Company ("SJLP")?

A. Yes. Inclusion of the effects of the SJLP merger will increase the total value of the power supply synergies available to MPS and Empire by approximately $20.4 million. Supporting data for this conclusion are contained in Schedule RWH-13. As indicated, the change in the ten year merger synergies is as shown below:

Change in Value of Synergies due to Inclusion of SJLP

	$x1,000
MPS	(3,106)
Empire	23,555
Total	20,449

Q. How were these results determined?

A. The same process, including the use of the RealTime model, as outlined above for the consolidation of the MPS and Empire power supply functions was used to analyze the combination of the three power supply systems. The increase in the value of the synergies available to Empire is due to the different allocation of both on system energy savings and off system sales margins.

CONCLUSION

Q. What can be concluded from your testimony?

A. Over the ten-year period 2001 - 2010, the expected benefits of combining the power supply functions of MPS and Empire will have a value of $180.8 million which consists of the following components:

	$x1000
Joint Planning & Dispatch	169,092
Human Resource	11,086
Other	589
Total	180,767

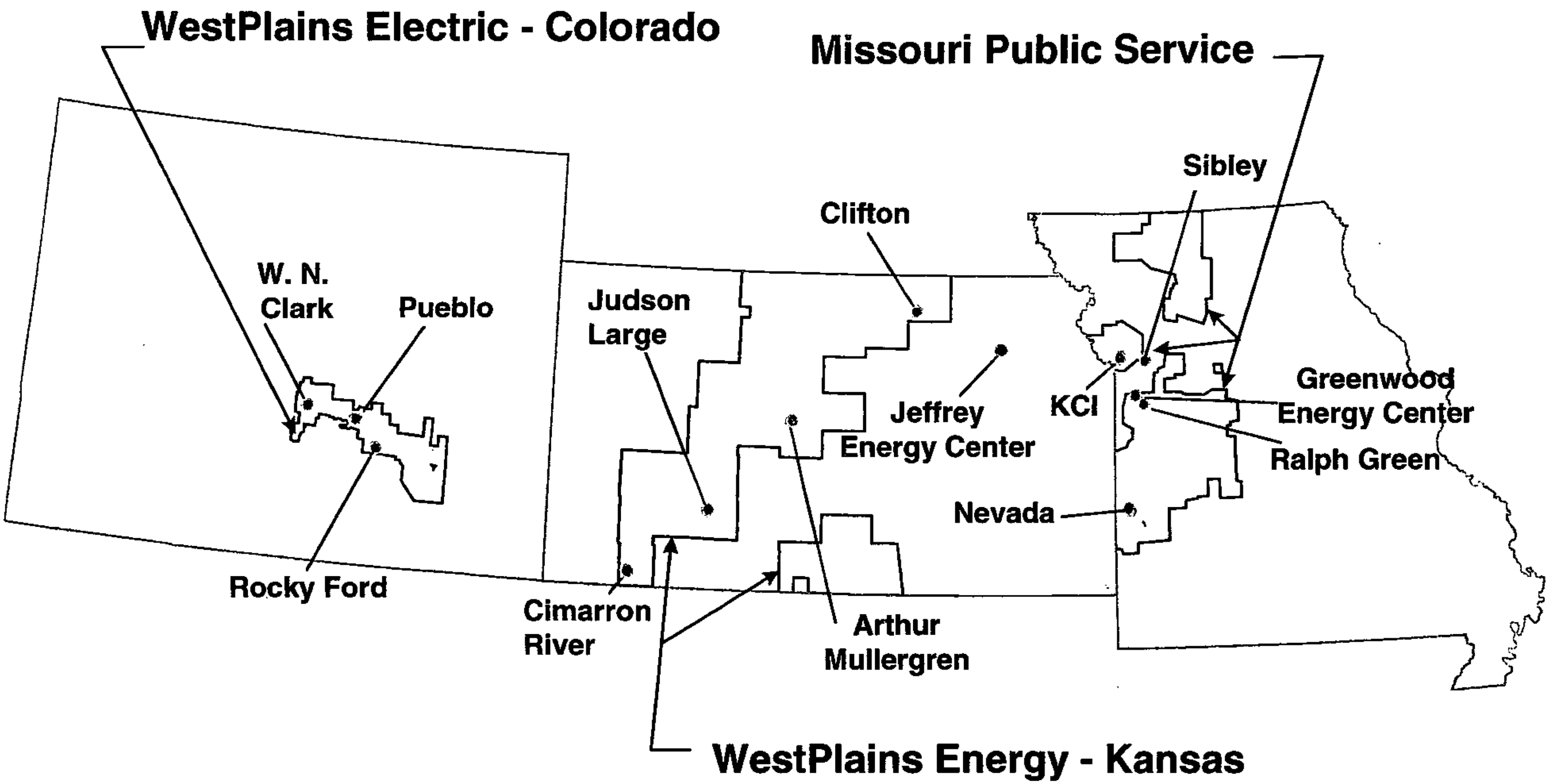
Finally, the value of the merger benefits allocated to Empire will be greater under a three way merger of MPS, Empire and SJLP than would result from a two way merger of MPS and Empire.

Q. Does this conclude your testimony?

A. Yes.

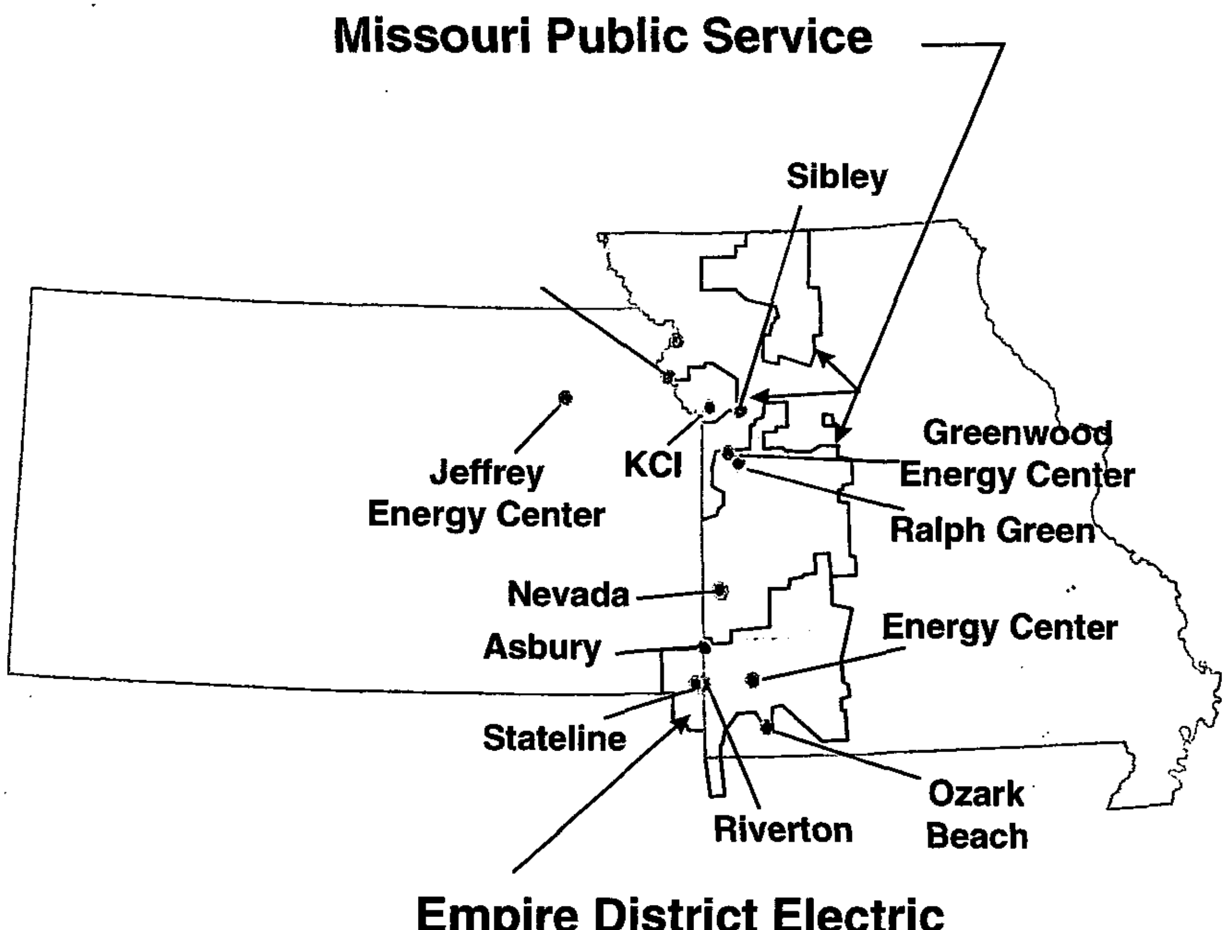
UtiliCorp United

MO / KS / CO Electric Operations



MPS & EDE

Electric Operations



Missouri Public Service Generation Units

Unit Name	Location	Net Output (MW)	Prime Mover	Primary Fuel	Year Installed	Notes
Sibley 1	Sibley, MO.	53	ST	Coal	1960	
Sibley 2	Sibley, MO.	53	ST	Coal	1962	
Sibley 3	Sibley, MO.	395	ST	Coal	1969	
Jeffrey Energy Ctr 1	St. Mary's, KS	59	ST	Coal	1978	1
Jeffrey Energy Ctr 2	St. Mary's, KS	59	ST	Coal	1980	1
Jeffrey Energy Ctr 3	St. Mary's, KS	59	ST	Coal	1983	1
Ralph Green 3	Pleasant Hill, MO	74	CT	Nat Gas	1981	
Greenwood 1	Greenwood, MO.	62	CT	Nat Gas	1975	
Greenwood 2	Greenwood, MO.	62	CT	Nat Gas	1975	
Greenwood 3	Greenwood, MO.	62	CT	Nat Gas	1977	
Greenwood 4	Greenwood, MO.	61	CT	Nat Gas	1979	
Nevada	Nevada, MO.	20	CT	#2 Oil	1974	
KCI 1	Kansas City, MO.	15	CT	Nat Gas	1971	
KCI 2	Kansas City, MO.	18	CT	Nat Gas	1971	
	Total:	1,053				

1. Jointly owned with Western Resources (84%) and WestPlains Electric - Kansas (a division of UtiliCorp United Inc.) (8%). Missouri Public Service ownership (8%) shown.

Empire District Electric Generation Units

Unit Name	Location	Net Output (MW)	Prime Mover	Primary Fuel	Year Installed	Notes
Asbury 1	Asbury, MO.	193	ST	Coal	1971	
Asbury 2	Asbury, MO.	20	ST	Coal	1986	
Iatan 1	Weston, MO.	80	ST	Coal	1980	1
Riverton 7	Riverton, KS.	38	ST	Coal	1950	
Riverton 8	Riverton, KS.	53	ST	Coal	1954	
Riverton 9	Riverton, KS.	12	CT	Nat Gas	1963	
Riverton 10	Riverton, KS.	16	CT	Nat Gas	1988	
Riverton 11	Riverton, KS.	17	CT	Nat Gas	1988	
Energy Center 1	LaRussell. MO.	90	CT	Nat Gas	1978	
Energy Center 2	LaRussell, MO.	90	CT	Nat Gas	1981	
State Line 1	Joplin, MO.	101	CT	Nat Gas	1995	
State Line 2	Joplin, MO.	152	CT	Nat Gas	1997	
Ozark Beach	Ozark Beach, MO.	16	Hydro	Hydro	1913	
	Total:	878				

1. Jointly owned with Kansas City Power and Light (70%) and St. Joseph Light & Power (18%). Empire District Electric ownership (12%) shown.

Missouri Public Service Purchase Power Contracts

Supplier	Initial Contract Term		Capacity Type	Summer Season Capacity in MW											
	From	To		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Associated Electric Cooperative, Inc.	6/1996	5/2000	System Contingent	100											
Associated Electric Cooperative, Inc.	6/1996	5/2000	System Contingent	90											
Kansas City, KS. Board of Public Utilities	7/1999	5/2001	Unit Contingent	92	92										
Aquila Energy Marketing Corporation (affiliate)	6/2000	9/2000	Unit Contingent		135										
MEP Pleasant Hill, LLC (affiliate)	6/2001	5/2005	Unit Contingent			320 (1)	500 (2)	500 (2)	500 (2)						

1. Capacity available for the months of June through September, 2001.

2. Capacity shown is available in the months of April though September, capacity for other months is 200 MW.

Empire District Electric Purchase Power Contracts

Supplier	Contract Term From	To	Capacity Type	Summer Season Capacity in MW 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Associated Electric Cooperative, Inc.	6/1/1993	5/31/2000	System Contingent	100											
Kansas Gas and Electric Company	6/1/1994	5/31/2001	System Contingent	80	80										
Western Resources, Inc.	6/1/1995	5/21/2010	Unit Contingent	30	162	162	162	162	162	162	162	162	162	162	
Southwestern Public Service Company	6/1/1993	5/31/2001	System Contingent	45	45										

SPP NORTH
Marginal Production Cost Forecast
$/MWh

ACTUAL $ @ Inflation Rate of: 2.5%

Season of Year	Time of Day	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FALL	OFF-PEAK	20.11	21.18	22.31	23.49	24.74	26.05	27.43	28.89	30.42	29.50	28.61	27.75
FALL	ON-PEAK	24.60	25.70	26.86	28.07	29.33	30.65	32.02	33.46	34.97	32.98	31.10	29.33
FALL	PEAK	28.12	29.09	30.10	31.15	32.23	33.35	34.51	35.71	36.95	34.57	32.34	30.25
SPRING	OFF-PEAK	19.06	20.11	21.22	22.40	23.64	24.95	26.33	27.79	29.33	28.65	27.99	27.35
SPRING	ON-PEAK	23.75	24.80	25.90	27.05	28.25	29.50	30.81	32.18	33.61	31.95	30.37	28.87
SPRING	PEAK	25.26	26.34	27.47	28.64	29.86	31.14	32.47	33.86	35.30	33.24	31.29	29.46
SUMMER	OFF-PEAK	19.15	20.31	21.54	22.84	24.22	25.69	27.24	28.88	30.63	29.05	27.55	26.13
SUMMER	ON-PEAK	21.39	22.98	24.68	26.52	28.48	30.60	32.87	35.30	37.92	35.29	32.83	30.55
SUMMER	PEAK	27.04	31.77	37.33	43.85	51.52	60.53	71.11	83.55	98.15	80.75	66.43	54.65
WINTER	OFF-PEAK	16.48	17.87	19.37	21.00	22.77	24.68	26.76	29.01	31.45	30.87	30.31	29.76
WINTER	ON-PEAK	19.00	20.46	22.04	23.74	25.56	27.53	29.65	31.94	34.40	33.17	31.99	30.85
WINTER	PEAK	19.60	21.05	22.62	24.30	26.10	28.04	30.13	32.37	34.77	33.45	32.19	30.97

Empire
Combined Cycle Expansion Plan

A. System Generation Capacity			2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity												
EDE	Iatan Share	Coal	80	80	80	80	80	80	80	80	80	80
EDE	Asbury 1	Coal	193	193	193	193	193	193	193	193	193	193
EDE	Rvrtn 7	Coal	38	38	38	38	38	38	38	38	38	38
EDE	Rvrtn 8	Coal	53	53	53	53	53	53	53	53	53	53
EMPR	Ozark Beach	Hydro	16	16	16	16	16	16	16	16	16	16
Total Base Capacity			380	380	380	380	380	380	380	380	380	380
EDE	SL CT1	Gas	101	101	101	101	101	101	101	101	101	101
EDE	SL CT2	Gas										
EDE	SL CC	Gas	300	300	300	300	300	300	300	300	300	300
EDE	EC 1	Gas	90	90	90	90	90	90	90	90	90	90
EDE	EC 2	Gas	90	90	90	90	90	90	90	90	90	90
EDE	Rvrtn 9	Gas	12	12	12	12	12	12	12	12	12	12
EDE	Rvrtn 10	Gas	16	16	16	16	16	16	16	16	16	16
EDE	Rvrtn 11	Gas	17	17	17	17	17	17	17	17	17	17
EDE	Asbury 2	Coal	20	20	20	20	20	20	20	20	20	20
Total Int/Peaking Capacity			646	646	646	646	646	646	646	646	646	646
Grand Total			1026	1026	1026	1026	1026	1026	1026	1026	1026	1026
Changes in Existing Capacity			0	0	0	0	0	0	0	0	0	0
New Generation Capacity			0	0	0	0	0	0	0	0	0	0
Total Generation Capacity			1026	1026	1026	1026	1026	1026	1026	1026	1026	1026

B. Capacity Transactions		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases											
EDE	AEC										
EDE	KGE										
EDE	SPS										
EDE	WRI	162	162	162	162	162	162	162	162	162	
EDE	CC Purchase #2										250
EDE	Shrt Term Purch #6					5	20	40	60	75	5
Total Purchases		162	162	162	162	167	182	202	222	237	255
Sales											
EDE											
Total Sales		0	0	0	0	0	0	0	0	0	0
Net Transactions		162	162	162	162	167	182	202	222	237	255
Total System Capacity (A+B)		1188	1188	1188	1188	1193	1208	1228	1248	1263	1281

C. System Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands										
Actual Peak										
Forecasted Peak	993	1010	1028	1044	1061	1077	1094	1110	1124	1139
DSM	14	14	14	14	14	14	14	14	14	14
Peak Forecast with DSM	979	996	1014	1030	1047	1063	1080	1096	1110	1125
Capacity Reserves (A+B-C)	209	192	174	158	146	145	148	152	153	156

D. Capacity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves										
Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1113	1132	1152	1170	1190	1208	1227	1245	1261	1278
Capacity Balance (A+B-D)	76	56	36	18	3	0	1	3	2	3

Empire
Combustion Turbine Expansion Plan

A. System Generation Capacity			2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity												
EDE	Iatan Share	Coal	80	80	80	80	80	80	80	80	80	80
EDE	Asbury 1	Coal	193	193	193	193	193	193	193	193	193	193
EDE	Rvrtn 7	Coal	38	38	38	38	38	38	38	38	38	38
EDE	Rvrtn 8	Coal	53	53	53	53	53	53	53	53	53	53
EDE	Ozark Beach	Hydro	16	16	16	16	16	16	16	16	16	16
Total Base Capacity			380	380	380	380	380	380	380	380	380	380
EDE	SL CT1	Gas	101	101	101	101	101	101	101	101	101	101
EDE	SL CT2	Gas										
EDE	SL CC	Gas	300	300	300	300	300	300	300	300	300	300
EDE	EC 1	Gas	90	90	90	90	90	90	90	90	90	90
EDE	EC 2	Gas	90	90	90	90	90	90	90	90	90	90
EDE	Rvrtn 9	Gas	12	12	12	12	12	12	12	12	12	12
EDE	Rvrtn 10	Gas	16	16	16	16	16	16	16	16	16	16
EDE	Rvrtn 11	Gas	17	17	17	17	17	17	17	17	17	17
EDE	Asbury 2	Coal	20	20	20	20	20	20	20	20	20	
Total Int/Peaking Capacity			646	646	646	646	646	646	646	646	646	626
Grand Total			1026	1026	1026	1026	1026	1026	1026	1026	1026	1006
Changes in Existing Capacity			0	0	0	0	0	0	0	0	0	0
New Generation Capacity			0	0	0	0	0	0	0	0	0	0
Total Generation Capacity			1026	1026	1026	1026	1026	1026	1026	1026	1026	1006

B. Capacity Transactions		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases											
EDE	AEC										
EDE	KGE										
EDE	SPS										
EDE	WRI	162	162	162	162	162	162	162	162	162	
EDE	CT Purchase #8										160
EDE	CT Purchase #9										160
EDE	Shrt Trm Purch #7					5	20	40	60	75	
Total Purchases		162	162	162	162	167	182	202	222	237	320
Sales											
EDE											
Total Sales		0	0	0	0	0	0	0	0	0	0
Net Transactions		162	162	162	162	167	182	202	222	237	320
Total System Capacity (A+B)		1188	1188	1188	1188	1193	1208	1228	1248	1263	1326

C. System Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands										
Actual Peak										
Forecasted Peak	993	1010	1028	1044	1061	1077	1094	1110	1124	1139
DSM	14	14	14	14	14	14	14	14	14	14
Peak Forecast with DSM	979	996	1014	1030	1047	1063	1080	1096	1110	1125
Capacity Reserves (A+B-C)	209	192	174	158	146	145	148	152	153	201

D. Capacity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves										
Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1113	1132	1152	1170	1190	1208	1227	1245	1261	1278
Capacity Balance (A+B-D)	76	56	36	18	3	0	1	3	2	48

MPS
Combined Cycle Expansion Plan

A. System Generation Capacity		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity											
MPS Sibley 1	Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 2	Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 3	Coal	395	410	410	410	410	410	410	410	410	410
MPS Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58
Total Base Capacity		677	692	692	692	692	692	692	692	692	692
MPS Ralph Green 3	Gas	74	74	74	74	74	74	74	74	74	74
MPS Greenwood 1	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 2	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 3	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 4	Gas	66	66	66	66	66	66	66	66	66	66
MPS Nevada	Oil	20	20	20	20	20	20	20	20	20	20
MPS TWA 1	Oil	18	18	18	18	18	18	18	18	18	18
MPS TWA 2	Oil	18	18	18	18	18	18	18	18	18	18
Total Int/Peaking Capacity		397	397	397	397	397	397	397	397	397	397
Grand Total		1074	1089	1089	1089	1089	1089	1089	1089	1089	1089
Changes in Existing Capacity		15	0	0	0	0	0	0	0	0	0
New Generation Capacity		0	0	0	0	0	0	0	0	0	0
Total Generation Capacity		1089	1089	1089	1089	1089	1089	1089	1089	1089	1089

B. Capacity Transactions	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases										
MPS Associated Electric Coop	0	0	0	0	0	0	0	0	0	0
MPS Kansas City Power & Light	0	0	0	0	0	0	0	0	0	0
MPS WPEKS	55	0	0	0	0	0	0	0	0	0
MPS PGET										
MPS Aquila Power										
MPS KC BPU										
MPS AMEP	320	500	500	500	0	0	0	0	0	0
MPS CT Purchase #4						160	160	160	160	160
MPS CT Purchase #7									160	160
MPS CC Purchase #1					250	250	250	250	250	250
MPS CC Purchase #1A					250	250	250	250	250	250
MPS Short Term Purch #1				10	60		5	60		10
Total Purchases	375	500	500	510	560	660	665	720	820	830
Sales										
MPS Tenaska										
MPS Colby										
Total Sales	0	0	0	0	0	0	0	0	0	0
Net Transactions	375	500	500	510	560	660	665	720	820	830
Total System Capacity (A+B)	1464	1589	1589	1599	1649	1749	1754	1809	1909	1919

C. System Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands										
Actual Peak										
Forecasted Peak	1286	1325	1366	1409	1453	1498	1545	1593	1643	1694
DSM	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Peak Forecast with DSM	1281	1320	1361	1404	1448	1493	1540	1588	1638	1689
Capacity Reserves (A+B-C)	183	269	228	195	201	256	214	221	271	230

D. Capacity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves										
MPS Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1456	1500	1547	1595	1645	1697	1750	1805	1861	1919
Capacity Balance (A+B-D)	8	89	42	4	4	52	4	4	48	(0)

MPS
Combustion Turbine Expansion Plan

A. System Generation Capacity		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity											
MPS Sibley 1	Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 2	Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 3	Coal	395	410	410	410	410	410	410	410	410	410
MPS Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58
Total Base Capacity		677	692	692	692	692	692	692	692	692	692
MPS Ralph Green 3	Gas	74	74	74	74	74	74	74	74	74	74
MPS Greenwood 1	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 2	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 3	Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 4	Gas	66	66	66	66	66	66	66	66	66	66
MPS Nevada	Oil	20	20	20	20	20	20	20	20	20	20
MPS TWA 1	Oil	18	18	18	18	18	18	18	18	18	18
MPS TWA 2	Oil	18	18	18	18	18	18	18	18	18	18
Total Int/Peaking Capacity		397	397	397	397	397	397	397	397	397	397
Grand Total		1074	1089	1089	1089	1089	1089	1089	1089	1089	1089
Changes in Existing Capacity		15	0	0	0	0	0	0	0	0	0
New Generation Capacity		0	0	0	0	0	0	0	0	0	0
Total Generation Capacity		1089	1089	1089	1089	1089	1089	1089	1089	1089	1089

B. Capacity Transactions	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases										
MPS Associated Electric Coop	0	0	0	0	0	0	0	0	0	0
MPS Kansas City Power & Light	0	0	0	0	0	0	0	0	0	0
MPS WPEKS	55	0	0	0	0	0	0	0	0	0
MPS PGET										
MPS Aquila Power										
MPS KC BPU										
MPS AMEP	320	500	500	500	0	0	0	0	0	0
MPS CT Purchase #1					160	160	160	160	160	160
MPS CT Purchase #2					160	160	160	160	160	160
MPS CT Purchase #3					160	160	160	160	160	160
MPS CT Purchase #4						160	160	160	160	160
MPS CT Purchase #7									160	160
MPS Shrt Trm Purch #2				10	80		25	80		30
Total Purchases	375	500	500	510	560	640	665	720	800	830
Sales										
MPS Tenaska										
MPS Colby										
Total Sales	0	0	0	0	0	0	0	0	0	0
Net Transactions	375	500	500	510	560	640	665	720	800	830
Total System Capacity (A+B)	1464	1589	1589	1599	1649	1729	1754	1809	1889	1919

C. System Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands										
Actual Peak										
Forecasted Peak	1286	1325	1366	1409	1453	1498	1545	1593	1643	1694
DSM	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Peak Forecast with DSM	1281	1320	1361	1404	1448	1493	1540	1588	1638	1689
Capacity Reserves (A+B-C)	183	269	228	195	201	236	214	221	251	230

D. Capacity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves										
MPS Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1456	1500	1547	1595	1645	1697	1750	1805	1861	1919
Capacity Balance (A+B-D)	8	89	42	4	4	32	4	4	28	(0)

MPS + Empire
Combined Cycle Expansion Plan

tem Generation Capacity			2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ting Generation Capacity												
MPS Sibley 1		Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 2		Coal	53	53	53	53	53	53	53	53	53	53
MPS Sibley 3		Coal	395	410	410	410	410	410	410	410	410	410
MPS Jeffrey EC 1		Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 2		Coal	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 3		Coal	58	58	58	58	58	58	58	58	58	58
EDE	Iatan Share	Coal	80	80	80	80	80	80	80	80	80	80
EDE	Asbury 1	Coal	193	193	193	193	193	193	193	193	193	193
EDE	Rvrtn 7	Coal	38	38	38	38	38	38	38	38	38	38
EDE	Rvrtn 8	Coal	53	53	53	53	53	53	53	53	53	53
EDE	Ozark Beach	Hydro	16	16	16	16	16	16	16	16	16	16
Total Base Capacity			1057	1072	1072	1072	1072	1072	1072	1072	1072	1072
MPS Ralph Green 3		Gas	74	74	74	74	74	74	74	74	74	74
MPS Greenwood 1		Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 2		Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 3		Gas	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 4		Gas	66	66	66	66	66	66	66	66	66	66
MPS Nevada		Oil	20	20	20	20	20	20	20	20	20	20
MPS TWA 1		Oil	18	18	18	18	18	18	18	18	18	18
MPS TWA 2		Oil	18	18	18	18	18	18	18	18	18	18
EDE	SL CT1	Gas	101	101	101	101	101	101	101	101	101	101
EDE	SL CT2	Gas	0	0	0	0	0	0	0	0	0	0
EDE	SL CC	Gas	300	300	300	300	300	300	300	300	300	300
EDE	EC 1	Gas	90	90	90	90	90	90	90	90	90	90
EDE	EC 2	Gas	90	90	90	90	90	90	90	90	90	90
EDE	Rvrtn 9	Gas	12	12	12	12	12	12	12	12	12	12
EDE	Rvrtn 10	Gas	16	16	16	16	16	16	16	16	16	16
EDE	Rvrtn 11	Gas	17	17	17	17	17	17	17	17	17	17
EDE	Asbury 2	Coal	20	20	20	20	20	20	20	20	20	20
Total Int/Peaking Capacity			1043	1043	1043	1043	1043	1043	1043	1043	1043	1043
Changes in Existing Capacity			15	0	0	0	0	0	0	0	0	0
New Generation Capacity			0	0	0	0	0	0	0	0	0	0
l Generation Capacity			2115	2115	2115	2115	2115	2115	2115	2115	2115	2115

acity Transactions		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases											
MPS Associated Electric Coop		0	0	0	0	0	0	0	0	0	0
MPS Kansas City Power & Light		0	0	0	0	0	0	0	0	0	0
MPS WPEKS		55	0	0	0	0	0	0	0	0	0
MPS PGET		0	0	0	0	0	0	0	0	0	0
MPS Aquila Power		0	0	0	0	0	0	0	0	0	0
MPS KC BPU		0	0	0	0	0	0	0	0	0	0
MPS Merchant Energy Partners		320	500	500	500	0	0	0	0	0	0
EDE	AEC	0	0	0	0	0	0	0	0	0	0
EDE	KGE	0	0	0	0	0	0	0	0	0	0
EDE	SPS	0	0	0	0	0	0	0	0	0	0
EDE	WRI	162	162	162	162	162	162	162	162	162	0
NCO CT Purchase #4							160	160	160	160	160
NCO CT Purchase #6									160	160	160
NCO CC Purchase #1						250	250	250	250	250	250
NCO CC Purchase #1A						250	250	250	250	250	250
NCO CC Purchase #2											250
NCO Shrt Trm Purch #9						40		25		10	
Total Purchases		537	662	662	662	702	822	847	982	992	1070

(continued on following page)

MPS + Empire
Combined Cycle Expansion Plan

Sales										
MPS Tenaska										
MPS Colby										
EDE										
Total Sales	0	0	0	0	0	0	0	0	0	0
Transactions	537	662	662	662	702	822	847	982	992	1070
l System Capacity (A+B)	2652	2777	2777	2777	2817	2937	2962	3097	3107	3185
tem Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Forecast										
MPS + EDE	2260	2316	2375	2434	2495	2556	2620	2684	2748	2814
Diversity	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Peak Demand	2246	2301	2360	2418	2479	2540	2603	2667	2730	2796
acity Reserves (A+B-C)	406	476	417	359	338	397	359	430	377	389
acity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
acity Reserves										
MPS Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
EDE Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
uired Capacity	2552	2615	2682	2748	2817	2886	2958	3031	3102	3177
acity Balance (A+B-D)	100	162	95	29	(0)	51	4	66	5	8

MPS + Empire
Combustion Turbine Expansion Plan

A. System Generation Capacity			2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity												
MPS	Sibley 1	Coal	53	53	53	53	53	53	53	53	53	53
MPS	Sibley 2	Coal	53	53	53	53	53	53	53	53	53	53
MPS	Sibley 3	Coal	395	410	410	410	410	410	410	410	410	410
MPS	Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59
MPS	Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59
MPS	Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58
EDE	Iatan Share	Coal	80	80	80	80	80	80	80	80	80	80
EDE	Asbury 1	Coal	193	193	193	193	193	193	193	193	193	193
EDE	Rvrtn 7	Coal	38	38	38	38	38	38	38	38	38	38
EDE	Rvrtn 8	Coal	53	53	53	53	53	53	53	53	53	53
EDE	Ozark Beach	Hydro	16	16	16	16	16	16	16	16	16	16
Total Base Capacity			1057	1072	1072	1072	1072	1072	1072	1072	1072	1072
MPS	Ralph Green 3	Gas	74	74	74	74	74	74	74	74	74	74
MPS	Greenwood 1	Gas	67	67	67	67	67	67	67	67	67	67
MPS	Greenwood 2	Gas	67	67	67	67	67	67	67	67	67	67
MPS	Greenwood 3	Gas	67	67	67	67	67	67	67	67	67	67
MPS	Greenwood 4	Gas	66	66	66	66	66	66	66	66	66	66
MPS	Nevada	Oil	20	20	20	20	20	20	20	20	20	20
MPS	TWA 1	Oil	18	18	18	18	18	18	18	18	18	18
MPS	TWA 2	Oil	18	18	18	18	18	18	18	18	18	18
EDE	SL CT1	Gas	101	101	101	101	101	101	101	101	101	101
EDE	SL CT2	Gas	0	0	0	0	0	0	0	0	0	0
EDE	SL CC	Gas	300	300	300	300	300	300	300	300	300	300
EDE	EC 1	Gas	90	90	90	90	90	90	90	90	90	90
EDE	EC 2	Gas	90	90	90	90	90	90	90	90	90	90
EDE	Rvrtn 9	Gas	12	12	12	12	12	12	12	12	12	12
EDE	Rvrtn 10	Gas	16	16	16	16	16	16	16	16	16	16
EDE	Rvrtn 11	Gas	17	17	17	17	17	17	17	17	17	17
EDE	Asbury 2	Coal	20	20	20	20	20	20	20	20	20	20
Total Int/Peaking Capacity			1043	1043	1043	1043	1043	1043	1043	1043	1043	1043
Changes in Existing Capacity			15	0	0	0	0	0	0	0	0	0
New Generation Capacity			0	0	0	0	0	0	0	0	0	0
Total Generation Capacity			2115	2115	2115	2115	2115	2115	2115	2115	2115	2115

B. Capacity Transactions		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases											
MPS	Associated Electric Coop	0	0	0	0	0	0	0	0	0	0
MPS	Kansas City Power & Light	0	0	0	0	0	0	0	0	0	0
MPS	WPEKS	55	0	0	0	0	0	0	0	0	0
MPS	PGET	0	0	0	0	0	0	0	0	0	0
MPS	Aquila Power	0	0	0	0	0	0	0	0	0	0
MPS	KC BPU	0	0	0	0	0	0	0	0	0	0
MPS	Merchant Energy Partners	320	500	500	500	0	0	0	0	0	0
EDE	AEC	0	0	0	0	0	0	0	0	0	0
EDE	KGE	0	0	0	0	0	0	0	0	0	0
EDE	SPS	0	0	0	0	0	0	0	0	0	0
EDE	WRI	162	162	162	162	162	162	162	162	162	0
NCO	CT Purchase #1					160	160	160	160	160	160
NCO	CT Purchase #2					160	160	160	160	160	160
NCO	CT Purchase #3					160	160	160	160	160	160
NCO	CT Purchase #4						160	160	160	160	160
NCO	CT Purchase #6								160	160	160
NCO	CT Purchase #8										160
NCO	CT Purchase #9										160
NCO	Shrt Trm Purch #8					60		45		30	
Total Purchases		537	662	662	662	702	802	847	962	992	1120

(continued on following page)

MPS + Empire
Combustion Turbine Expansion Plan

Sales										
MPS Tenaska										
MPS Colby										
EDE										
Total Sales	0	0	0	0	0	0	0	0	0	0
Net Transactions	537	662	662	662	702	802	847	962	992	1120
Total System Capacity (A+B)	2652	2777	2777	2777	2817	2917	2962	3077	3107	3235
C. System Peaks & Reserves	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Forecast										
MPS + EDE	2260	2316	2375	2434	2495	2556	2620	2684	2748	2814
Diversity	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Peak Demand	2246	2301	2360	2418	2479	2540	2603	2667	2730	2796
Capacity Reserves (A+B-C)	406	476	417	359	338	377	359	410	377	439
D. Capacity Needs	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves										
MPS Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
EDE Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	2552	2615	2682	2748	2817	2886	2958	3031	3102	3177
Capacity Balance (A+B-D)	100	162	95	29	(0)	31	4	46	5	58

Capacity Ownership Cost Summary

Combustion Turbine Capacity Cost

	Monthly Capacity Charge - $/kw-mo.										
In Service Year >	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Sht Term
2001	6.17										6.17
2002	6.09	6.30									6.30
2003	6.01	6.21	6.43								6.43
2004	5.92	6.13	6.35	6.57							6.57
2005	5.84	6.05	6.26	6.48	6.71						6.71
2006	5.76	5.96	6.17	6.39	6.62	6.85					6.85
2007	5.68	5.88	6.09	6.30	6.52	6.75	6.99				6.99
2008	5.60	5.80	6.00	6.21	6.43	6.66	6.90	7.14			7.14
2009	5.52	5.72	5.92	6.13	6.34	6.57	6.80	7.04	7.30		7.30
2010	5.44	5.63	5.83	6.04	6.25	6.47	6.71	6.95	7.19	7.45	7.45

Combined Cycle Capacity Cost

	Monthly Capacity Charge - $/kw-mo.					
In Service Year >	2005	2006	2007	2008	2009	2010
2005	9.51					
2006	9.37					
2007	9.23					
2008	9.10					
2009	8.96					
2010	8.82					10.62

CT2001
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2001	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$72.26	$70.40	$68.91	$67.75	$66.86	$64.71	/kw-yr.
Levelized Annual Revenue Required:	$ 6.02	$ 5.87	$ 5.74	$ 5.65	$ 5.57	$ 5.39	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2001	323.07	19.38	12.92	9.23	7.56	3.23	2.15	19.55	74.03	6.17
2002	313.84	18.83	12.55	9.23	7.34	3.14	2.21	19.74	73.05	6.09
2003	304.61	18.28	12.18	9.23	7.13	3.05	2.26	19.94	72.07	6.01
2004	295.38	17.72	11.82	9.23	6.91	2.95	2.32	20.14	71.09	5.92
2005	286.15	17.17	11.45	9.23	6.70	2.86	2.38	20.34	70.12	5.84
2006	276.91	16.61	11.08	9.23	6.48	2.77	2.44	20.54	69.15	5.76
2007	267.68	16.06	10.71	9.23	6.26	2.68	2.50	20.75	68.19	5.68
2008	258.45	15.51	10.34	9.23	6.05	2.58	2.56	20.96	67.23	5.60
2009	249.22	14.95	9.97	9.23	5.83	2.49	2.62	21.17	66.27	5.52
2010	239.99	14.40	9.60	9.23	5.62	2.40	2.69	21.38	65.31	5.44
2011	230.76	13.85	9.23	9.23	5.40	2.31	2.76	21.59	64.36	5.36
2012	221.53	13.29	8.86	9.23	5.18	2.22	2.83	21.81	63.42	5.28
2013	212.30	12.74	8.49	9.23	4.97	2.12	2.90	22.03	62.47	5.21
2014	203.07	12.18	8.12	9.23	4.75	2.03	2.97	22.25	61.54	5.13
2015	193.84	11.63	7.75	9.23	4.54	1.94	3.04	22.47	60.60	5.05
2016	184.61	11.08	7.38	9.23	4.32	1.85	3.12	22.69	59.67	4.97
2017	175.38	10.52	7.02	9.23	4.10	1.75	3.20	22.92	58.74	4.90
2018	166.15	9.97	6.65	9.23	3.89	1.66	3.28	23.15	57.82	4.82
2019	156.92	9.42	6.28	9.23	3.67	1.57	3.36	23.38	56.90	4.74
2020	147.69	8.86	5.91	9.23	3.46	1.48	3.44	23.61	55.99	4.67
2021	138.46	8.31	5.54	9.23	3.24	1.38	3.53	23.85	55.08	4.59
2022	129.23	7.75	5.17	9.23	3.02	1.29	3.62	24.09	54.18	4.51
2023	120.00	7.20	4.80	9.23	2.81	1.20	3.71	24.33	53.28	4.44
2024	110.77	6.65	4.43	9.23	2.59	1.11	3.80	24.57	52.38	4.37
2025	101.54	6.09	4.06	9.23	2.38	1.02	3.90	24.82	51.49	4.29
2026	92.30	5.54	3.69	9.23	2.16	0.92	3.99	25.07	50.60	4.22
2027	83.07	4.98	3.32	9.23	1.94	0.83	4.09	25.32	49.72	4.14
2028	73.84	4.43	2.95	9.23	1.73	0.74	4.20	25.57	48.85	4.07
2029	64.61	3.88	2.58	9.23	1.51	0.65	4.30	25.83	47.98	4.00
2030	55.38	3.32	2.22	9.23	1.30	0.55	4.41	26.09	47.11	3.93

CT2002
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2002	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$73.76	$71.86	$70.33	$69.13	$68.22	$66.01	/kw-yr.
Levelized Annual Revenue Required:	$ 6.15	$ 5.99	$ 5.86	$ 5.76	$ 5.68	$ 5.50	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2002	331.14	19.87	13.25	9.46	7.75	3.31	2.21	19.74	75.59	6.30
2003	321.68	19.30	12.87	9.46	7.53	3.22	2.26	19.94	74.58	6.21
2004	312.22	18.73	12.49	9.46	7.31	3.12	2.32	20.14	73.57	6.13
2005	302.76	18.17	12.11	9.46	7.08	3.03	2.38	20.34	72.57	6.05
2006	293.30	17.60	11.73	9.46	6.86	2.93	2.44	20.54	71.57	5.96
2007	283.84	17.03	11.35	9.46	6.64	2.84	2.50	20.75	70.57	5.88
2008	274.38	16.46	10.98	9.46	6.42	2.74	2.56	20.96	69.58	5.80
2009	264.92	15.89	10.60	9.46	6.20	2.65	2.62	21.17	68.59	5.72
2010	255.45	15.33	10.22	9.46	5.98	2.55	2.69	21.38	67.61	5.63
2011	245.99	14.76	9.84	9.46	5.76	2.46	2.76	21.59	66.63	5.55
2012	236.53	14.19	9.46	9.46	5.53	2.37	2.83	21.81	65.65	5.47
2013	227.07	13.62	9.08	9.46	5.31	2.27	2.90	22.03	64.67	5.39
2014	217.61	13.06	8.70	9.46	5.09	2.18	2.97	22.25	63.71	5.31
2015	208.15	12.49	8.33	9.46	4.87	2.08	3.04	22.47	62.74	5.23
2016	198.69	11.92	7.95	9.46	4.65	1.99	3.12	22.69	61.78	5.15
2017	189.23	11.35	7.57	9.46	4.43	1.89	3.20	22.92	60.82	5.07
2018	179.76	10.79	7.19	9.46	4.21	1.80	3.28	23.15	59.87	4.99
2019	170.30	10.22	6.81	9.46	3.99	1.70	3.36	23.38	58.92	4.91
2020	160.84	9.65	6.43	9.46	3.76	1.61	3.44	23.61	57.98	4.83
2021	151.38	9.08	6.06	9.46	3.54	1.51	3.53	23.85	57.04	4.75
2022	141.92	8.52	5.68	9.46	3.32	1.42	3.62	24.09	56.10	4.68
2023	132.46	7.95	5.30	9.46	3.10	1.32	3.71	24.33	55.17	4.60
2024	123.00	7.38	4.92	9.46	2.88	1.23	3.80	24.57	54.24	4.52
2025	113.54	6.81	4.54	9.46	2.66	1.14	3.90	24.82	53.32	4.44
2026	104.07	6.24	4.16	9.46	2.44	1.04	3.99	25.07	52.41	4.37
2027	94.61	5.68	3.78	9.46	2.21	0.95	4.09	25.32	51.49	4.29
2028	85.15	5.11	3.41	9.46	1.99	0.85	4.20	25.57	50.59	4.22
2029	75.69	4.54	3.03	9.46	1.77	0.76	4.30	25.83	49.69	4.14
2030	66.23	3.97	2.65	9.46	1.55	0.66	4.41	26.09	48.79	4.07
2031	56.77	3.41	2.27	9.46	1.33	0.57	4.52	26.35	47.90	3.99

CT2003
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2003	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$75.31	$73.34	$71.77	$70.54	$69.60	$67.35	/kw-yr.
Levelized Annual Revenue Required:	$ 6.28	$ 6.11	$ 5.98	$ 5.88	$ 5.80	$ 5.61	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2003	339.42	20.37	13.58	9.70	7.94	3.39	2.26	19.94	77.18	6.43
2004	329.72	19.78	13.19	9.70	7.72	3.30	2.32	20.14	76.14	6.35
2005	320.03	19.20	12.80	9.70	7.49	3.20	2.38	20.34	75.11	6.26
2006	310.33	18.62	12.41	9.70	7.26	3.10	2.44	20.54	74.08	6.17
2007	300.63	18.04	12.03	9.70	7.03	3.01	2.50	20.75	73.05	6.09
2008	290.93	17.46	11.64	9.70	6.81	2.91	2.56	20.96	72.03	6.00
2009	281.24	16.87	11.25	9.70	6.58	2.81	2.62	21.17	71.01	5.92
2010	271.54	16.29	10.86	9.70	6.35	2.72	2.69	21.38	69.99	5.83
2011	261.84	15.71	10.47	9.70	6.13	2.62	2.76	21.59	68.98	5.75
2012	252.14	15.13	10.09	9.70	5.90	2.52	2.83	21.81	67.97	5.66
2013	242.44	14.55	9.70	9.70	5.67	2.42	2.90	22.03	66.96	5.58
2014	232.75	13.96	9.31	9.70	5.45	2.33	2.97	22.25	65.96	5.50
2015	223.05	13.38	8.92	9.70	5.22	2.23	3.04	22.47	64.96	5.41
2016	213.35	12.80	8.53	9.70	4.99	2.13	3.12	22.69	63.97	5.33
2017	203.65	12.22	8.15	9.70	4.77	2.04	3.20	22.92	62.98	5.25
2018	193.96	11.64	7.76	9.70	4.54	1.94	3.28	23.15	62.00	5.17
2019	184.26	11.06	7.37	9.70	4.31	1.84	3.36	23.38	61.02	5.08
2020	174.56	10.47	6.98	9.70	4.08	1.75	3.44	23.61	60.04	5.00
2021	164.86	9.89	6.59	9.70	3.86	1.65	3.53	23.85	59.07	4.92
2022	155.16	9.31	6.21	9.70	3.63	1.55	3.62	24.09	58.10	4.84
2023	145.47	8.73	5.82	9.70	3.40	1.45	3.71	24.33	57.14	4.76
2024	135.77	8.15	5.43	9.70	3.18	1.36	3.80	24.57	56.18	4.68
2025	126.07	7.56	5.04	9.70	2.95	1.26	3.90	24.82	55.23	4.60
2026	116.37	6.98	4.65	9.70	2.72	1.16	3.99	25.07	54.28	4.52
2027	106.68	6.40	4.27	9.70	2.50	1.07	4.09	25.32	53.34	4.44
2028	96.98	5.82	3.88	9.70	2.27	0.97	4.20	25.57	52.40	4.37
2029	87.28	5.24	3.49	9.70	2.04	0.87	4.30	25.83	51.47	4.29
2030	77.58	4.65	3.10	9.70	1.82	0.78	4.41	26.09	50.54	4.21
2031	67.88	4.07	2.72	9.70	1.59	0.68	4.52	26.35	49.62	4.13
2032	58.19	3.49	2.33	9.70	1.36	0.58	4.63	26.61	48.70	4.06

CT2004
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2004	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$76.88	$74.87	$73.25	$71.99	$71.02	$68.72	/kw-yr.
Levelized Annual Revenue Required:	$ 6.41	$ 6.24	$ 6.10	$ 6.00	$ 5.92	$ 5.73	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2004	347.91	20.87	13.92	9.94	8.14	3.48	2.32	20.14	78.81	6.57
2005	337.97	20.28	13.52	9.94	7.91	3.38	2.38	20.34	77.74	6.48
2006	328.03	19.68	13.12	9.94	7.68	3.28	2.44	20.54	76.68	6.39
2007	318.09	19.09	12.72	9.94	7.44	3.18	2.50	20.75	75.62	6.30
2008	308.15	18.49	12.33	9.94	7.21	3.08	2.56	20.96	74.56	6.21
2009	298.21	17.89	11.93	9.94	6.98	2.98	2.62	21.17	73.51	6.13
2010	288.27	17.30	11.53	9.94	6.75	2.88	2.69	21.38	72.46	6.04
2011	278.33	16.70	11.13	9.94	6.51	2.78	2.76	21.59	71.42	5.95
2012	268.39	16.10	10.74	9.94	6.28	2.68	2.83	21.81	70.38	5.86
2013	258.45	15.51	10.34	9.94	6.05	2.58	2.90	22.03	69.34	5.78
2014	248.51	14.91	9.94	9.94	5.82	2.49	2.97	22.25	68.31	5.69
2015	238.57	14.31	9.54	9.94	5.58	2.39	3.04	22.47	67.28	5.61
2016	228.63	13.72	9.15	9.94	5.35	2.29	3.12	22.69	66.25	5.52
2017	218.69	13.12	8.75	9.94	5.12	2.19	3.20	22.92	65.23	5.44
2018	208.74	12.52	8.35	9.94	4.88	2.09	3.28	23.15	64.21	5.35
2019	198.80	11.93	7.95	9.94	4.65	1.99	3.36	23.38	63.20	5.27
2020	188.86	11.33	7.55	9.94	4.42	1.89	3.44	23.61	62.19	5.18
2021	178.92	10.74	7.16	9.94	4.19	1.79	3.53	23.85	61.19	5.10
2022	168.98	10.14	6.76	9.94	3.95	1.69	3.62	24.09	60.19	5.02
2023	159.04	9.54	6.36	9.94	3.72	1.59	3.71	24.33	59.19	4.93
2024	149.10	8.95	5.96	9.94	3.49	1.49	3.80	24.57	58.20	4.85
2025	139.16	8.35	5.57	9.94	3.26	1.39	3.90	24.82	57.22	4.77
2026	129.22	7.75	5.17	9.94	3.02	1.29	3.99	25.07	56.24	4.69
2027	119.28	7.16	4.77	9.94	2.79	1.19	4.09	25.32	55.26	4.61
2028	109.34	6.56	4.37	9.94	2.56	1.09	4.20	25.57	54.29	4.52
2029	99.40	5.96	3.98	9.94	2.33	0.99	4.30	25.83	53.33	4.44
2030	89.46	5.37	3.58	9.94	2.09	0.89	4.41	26.09	52.37	4.36
2031	79.52	4.77	3.18	9.94	1.86	0.80	4.52	26.35	51.41	4.28
2032	69.58	4.17	2.78	9.94	1.63	0.70	4.63	26.61	50.46	4.21
2033	59.64	3.58	2.39	9.94	1.40	0.60	4.75	26.88	49.52	4.13

CT2005
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2005	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$78.50	$76.43	$74.76	$73.46	$72.47	$70.11	/kw-yr.
Levelized Annual Revenue Required:	$ 6.54	$ 6.37	$ 6.23	$ 6.12	$ 6.04	$ 5.84	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2005	356.61	21.40	14.26	10.19	8.34	3.57	2.38	20.34	80.48	6.71
2006	346.42	20.79	13.86	10.19	8.11	3.46	2.44	20.54	79.38	6.62
2007	336.23	20.17	13.45	10.19	7.87	3.36	2.50	20.75	78.29	6.52
2008	326.04	19.56	13.04	10.19	7.63	3.26	2.56	20.96	77.20	6.43
2009	315.85	18.95	12.63	10.19	7.39	3.16	2.62	21.17	76.11	6.34
2010	305.66	18.34	12.23	10.19	7.15	3.06	2.69	21.38	75.03	6.25
2011	295.47	17.73	11.82	10.19	6.91	2.95	2.76	21.59	73.95	6.16
2012	285.28	17.12	11.41	10.19	6.68	2.85	2.83	21.81	72.88	6.07
2013	275.10	16.51	11.00	10.19	6.44	2.75	2.90	22.03	71.81	5.98
2014	264.91	15.89	10.60	10.19	6.20	2.65	2.97	22.25	70.74	5.90
2015	254.72	15.28	10.19	10.19	5.96	2.55	3.04	22.47	69.68	5.81
2016	244.53	14.67	9.78	10.19	5.72	2.45	3.12	22.69	68.62	5.72
2017	234.34	14.06	9.37	10.19	5.48	2.34	3.20	22.92	67.57	5.63
2018	224.15	13.45	8.97	10.19	5.25	2.24	3.28	23.15	66.52	5.54
2019	213.96	12.84	8.56	10.19	5.01	2.14	3.36	23.38	65.47	5.46
2020	203.77	12.23	8.15	10.19	4.77	2.04	3.44	23.61	64.43	5.37
2021	193.59	11.62	7.74	10.19	4.53	1.94	3.53	23.85	63.39	5.28
2022	183.40	11.00	7.34	10.19	4.29	1.83	3.62	24.09	62.36	5.20
2023	173.21	10.39	6.93	10.19	4.05	1.73	3.71	24.33	61.33	5.11
2024	163.02	9.78	6.52	10.19	3.81	1.63	3.80	24.57	60.31	5.03
2025	152.83	9.17	6.11	10.19	3.58	1.53	3.90	24.82	59.29	4.94
2026	142.64	8.56	5.71	10.19	3.34	1.43	3.99	25.07	58.28	4.86
2027	132.45	7.95	5.30	10.19	3.10	1.32	4.09	25.32	57.27	4.77
2028	122.26	7.34	4.89	10.19	2.86	1.22	4.20	25.57	56.27	4.69
2029	112.08	6.72	4.48	10.19	2.62	1.12	4.30	25.83	55.27	4.61
2030	101.89	6.11	4.08	10.19	2.38	1.02	4.41	26.09	54.27	4.52
2031	91.70	5.50	3.67	10.19	2.15	0.92	4.52	26.35	53.29	4.44
2032	81.51	4.89	3.26	10.19	1.91	0.82	4.63	26.61	52.30	4.36
2033	71.32	4.28	2.85	10.19	1.67	0.71	4.75	26.88	51.33	4.28
2034	61.13	3.67	2.45	10.19	1.43	0.61	4.87	27.14	50.35	4.20

CT2006
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2006	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$80.15	$78.02	$76.31	$74.97	$73.95	$71.54	/kw-yr.
Levelized Annual Revenue Required:	$ 6.68	$ 6.50	$ 6.36	$ 6.25	$ 6.16	$ 5.96	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2006	365.52	21.93	14.62	10.44	8.55	3.66	2.44	20.54	82.18	6.85
2007	355.08	21.30	14.20	10.44	8.31	3.55	2.50	20.75	81.06	6.75
2008	344.63	20.68	13.79	10.44	8.06	3.45	2.56	20.96	79.93	6.66
2009	334.19	20.05	13.37	10.44	7.82	3.34	2.62	21.17	78.82	6.57
2010	323.75	19.42	12.95	10.44	7.58	3.24	2.69	21.38	77.70	6.47
2011	313.30	18.80	12.53	10.44	7.33	3.13	2.76	21.59	76.59	6.38
2012	302.86	18.17	12.11	10.44	7.09	3.03	2.83	21.81	75.48	6.29
2013	292.42	17.55	11.70	10.44	6.84	2.92	2.90	22.03	74.37	6.20
2014	281.97	16.92	11.28	10.44	6.60	2.82	2.97	22.25	73.27	6.11
2015	271.53	16.29	10.86	10.44	6.35	2.72	3.04	22.47	72.18	6.01
2016	261.09	15.67	10.44	10.44	6.11	2.61	3.12	22.69	71.08	5.92
2017	250.64	15.04	10.03	10.44	5.87	2.51	3.20	22.92	70.00	5.83
2018	240.20	14.41	9.61	10.44	5.62	2.40	3.28	23.15	68.91	5.74
2019	229.76	13.79	9.19	10.44	5.38	2.30	3.36	23.38	67.83	5.65
2020	219.31	13.16	8.77	10.44	5.13	2.19	3.44	23.61	66.76	5.56
2021	208.87	12.53	8.35	10.44	4.89	2.09	3.53	23.85	65.69	5.47
2022	198.43	11.91	7.94	10.44	4.64	1.98	3.62	24.09	64.62	5.39
2023	187.98	11.28	7.52	10.44	4.40	1.88	3.71	24.33	63.56	5.30
2024	177.54	10.65	7.10	10.44	4.15	1.78	3.80	24.57	62.50	5.21
2025	167.10	10.03	6.68	10.44	3.91	1.67	3.90	24.82	61.45	5.12
2026	156.65	9.40	6.27	10.44	3.67	1.57	3.99	25.07	60.40	5.03
2027	146.21	8.77	5.85	10.44	3.42	1.46	4.09	25.32	59.36	4.95
2028	135.76	8.15	5.43	10.44	3.18	1.36	4.20	25.57	58.32	4.86
2029	125.32	7.52	5.01	10.44	2.93	1.25	4.30	25.83	57.29	4.77
2030	114.88	6.89	4.60	10.44	2.69	1.15	4.41	26.09	56.26	4.69
2031	104.43	6.27	4.18	10.44	2.44	1.04	4.52	26.35	55.24	4.60
2032	93.99	5.64	3.76	10.44	2.20	0.94	4.63	26.61	54.22	4.52
2033	83.55	5.01	3.34	10.44	1.96	0.84	4.75	26.88	53.21	4.43
2034	73.10	4.39	2.92	10.44	1.71	0.73	4.87	27.14	52.21	4.35
2035	62.66	3.76	2.51	10.44	1.47	0.63	4.99	27.42	51.21	4.27

CT2007
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2007	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$81.84	$79.65	$77.89	$76.52	$75.47	$73.00	/kw-yr.
Levelized Annual Revenue Required:	$ 6.82	$ 6.64	$ 6.49	$ 6.38	$ 6.29	$ 6.08	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2007	374.66	22.48	14.99	10.70	8.77	3.75	2.50	20.75	83.93	6.99
2008	363.95	21.84	14.56	10.70	8.52	3.64	2.56	20.96	82.77	6.90
2009	353.25	21.19	14.13	10.70	8.27	3.53	2.62	21.17	81.62	6.80
2010	342.55	20.55	13.70	10.70	8.02	3.43	2.69	21.38	80.47	6.71
2011	331.84	19.91	13.27	10.70	7.77	3.32	2.76	21.59	79.32	6.61
2012	321.14	19.27	12.85	10.70	7.51	3.21	2.83	21.81	78.18	6.51
2013	310.43	18.63	12.42	10.70	7.26	3.10	2.90	22.03	77.04	6.42
2014	299.73	17.98	11.99	10.70	7.01	3.00	2.97	22.25	75.90	6.33
2015	289.02	17.34	11.56	10.70	6.76	2.89	3.04	22.47	74.77	6.23
2016	278.32	16.70	11.13	10.70	6.51	2.78	3.12	22.69	73.64	6.14
2017	267.61	16.06	10.70	10.70	6.26	2.68	3.20	22.92	72.52	6.04
2018	256.91	15.41	10.28	10.70	6.01	2.57	3.28	23.15	71.40	5.95
2019	246.20	14.77	9.85	10.70	5.76	2.46	3.36	23.38	70.29	5.86
2020	235.50	14.13	9.42	10.70	5.51	2.35	3.44	23.61	69.18	5.76
2021	224.80	13.49	8.99	10.70	5.26	2.25	3.53	23.85	68.07	5.67
2022	214.09	12.85	8.56	10.70	5.01	2.14	3.62	24.09	66.97	5.58
2023	203.39	12.20	8.14	10.70	4.76	2.03	3.71	24.33	65.87	5.49
2024	192.68	11.56	7.71	10.70	4.51	1.93	3.80	24.57	64.78	5.40
2025	181.98	10.92	7.28	10.70	4.26	1.82	3.90	24.82	63.70	5.31
2026	171.27	10.28	6.85	10.70	4.01	1.71	3.99	25.07	62.61	5.22
2027	160.57	9.63	6.42	10.70	3.76	1.61	4.09	25.32	61.54	5.13
2028	149.86	8.99	5.99	10.70	3.51	1.50	4.20	25.57	60.46	5.04
2029	139.16	8.35	5.57	10.70	3.26	1.39	4.30	25.83	59.40	4.95
2030	128.45	7.71	5.14	10.70	3.01	1.28	4.41	26.09	58.33	4.86
2031	117.75	7.06	4.71	10.70	2.76	1.18	4.52	26.35	57.28	4.77
2032	107.05	6.42	4.28	10.70	2.50	1.07	4.63	26.61	56.22	4.69
2033	96.34	5.78	3.85	10.70	2.25	0.96	4.75	26.88	55.18	4.60
2034	85.64	5.14	3.43	10.70	2.00	0.86	4.87	27.14	54.14	4.51
2035	74.93	4.50	3.00	10.70	1.75	0.75	4.99	27.42	53.10	4.43
2036	64.23	3.85	2.57	10.70	1.50	0.64	5.11	27.69	52.07	4.34

CT2008
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2008	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$83.57	$81.32	$79.51	$78.10	$77.02	$74.50	/kw-yr.
Levelized Annual Revenue Required:	$ 6.96	$ 6.78	$ 6.63	$ 6.51	$ 6.42	$ 6.21	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2008	384.03	23.04	15.36	10.97	8.99	3.84	2.56	20.96	85.72	7.14
2009	373.05	22.38	14.92	10.97	8.73	3.73	2.62	21.17	84.53	7.04
2010	362.08	21.72	14.48	10.97	8.47	3.62	2.69	21.38	83.34	6.95
2011	351.11	21.07	14.04	10.97	8.22	3.51	2.76	21.59	82.16	6.85
2012	340.14	20.41	13.61	10.97	7.96	3.40	2.83	21.81	80.98	6.75
2013	329.16	19.75	13.17	10.97	7.70	3.29	2.90	22.03	79.81	6.65
2014	318.19	19.09	12.73	10.97	7.45	3.18	2.97	22.25	78.63	6.55
2015	307.22	18.43	12.29	10.97	7.19	3.07	3.04	22.47	77.47	6.46
2016	296.25	17.77	11.85	10.97	6.93	2.96	3.12	22.69	76.30	6.36
2017	285.28	17.12	11.41	10.97	6.68	2.85	3.20	22.92	75.15	6.26
2018	274.30	16.46	10.97	10.97	6.42	2.74	3.28	23.15	73.99	6.17
2019	263.33	15.80	10.53	10.97	6.16	2.63	3.36	23.38	72.84	6.07
2020	252.36	15.14	10.09	10.97	5.91	2.52	3.44	23.61	71.69	5.97
2021	241.39	14.48	9.66	10.97	5.65	2.41	3.53	23.85	70.55	5.88
2022	230.42	13.82	9.22	10.97	5.39	2.30	3.62	24.09	69.42	5.78
2023	219.44	13.17	8.78	10.97	5.13	2.19	3.71	24.33	68.28	5.69
2024	208.47	12.51	8.34	10.97	4.88	2.08	3.80	24.57	67.16	5.60
2025	197.50	11.85	7.90	10.97	4.62	1.97	3.90	24.82	66.03	5.50
2026	186.53	11.19	7.46	10.97	4.36	1.87	3.99	25.07	64.92	5.41
2027	175.55	10.53	7.02	10.97	4.11	1.76	4.09	25.32	63.80	5.32
2028	164.58	9.87	6.58	10.97	3.85	1.65	4.20	25.57	62.69	5.22
2029	153.61	9.22	6.14	10.97	3.59	1.54	4.30	25.83	61.59	5.13
2030	142.64	8.56	5.71	10.97	3.34	1.43	4.41	26.09	60.49	5.04
2031	131.67	7.90	5.27	10.97	3.08	1.32	4.52	26.35	59.40	4.95
2032	120.69	7.24	4.83	10.97	2.82	1.21	4.63	26.61	58.31	4.86
2033	109.72	6.58	4.39	10.97	2.57	1.10	4.75	26.88	57.23	4.77
2034	98.75	5.92	3.95	10.97	2.31	0.99	4.87	27.14	56.15	4.68
2035	87.78	5.27	3.51	10.97	2.05	0.88	4.99	27.42	55.08	4.59
2036	76.81	4.61	3.07	10.97	1.80	0.77	5.11	27.69	54.02	4.50
2037	65.83	3.95	2.63	10.97	1.54	0.66	5.24	27.97	52.96	4.41

CT2009
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%
In Service Date	2009	Fixed O&M in $/kw-yr (1998$)	$ 2.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$85.34	$83.03	$81.17	$79.72	$78.61	$76.02	/kw-yr.
Levelized Annual Revenue Required:	$ 7.11	$ 6.92	$ 6.76	$ 6.64	$ 6.55	$ 6.34	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2009	393.63	23.62	15.75	11.25	9.21	3.94	2.62	21.17	87.55	7.30
2010	382.38	22.94	15.30	11.25	8.95	3.82	2.69	21.38	86.32	7.19
2011	371.13	22.27	14.85	11.25	8.68	3.71	2.76	21.59	85.10	7.09
2012	359.89	21.59	14.40	11.25	8.42	3.60	2.83	21.81	83.89	6.99
2013	348.64	20.92	13.95	11.25	8.16	3.49	2.90	22.03	82.68	6.89
2014	337.39	20.24	13.50	11.25	7.90	3.37	2.97	22.25	81.47	6.79
2015	326.15	19.57	13.05	11.25	7.63	3.26	3.04	22.47	80.27	6.69
2016	314.90	18.89	12.60	11.25	7.37	3.15	3.12	22.69	79.07	6.59
2017	303.65	18.22	12.15	11.25	7.11	3.04	3.20	22.92	77.87	6.49
2018	292.41	17.54	11.70	11.25	6.84	2.92	3.28	23.15	76.68	6.39
2019	281.16	16.87	11.25	11.25	6.58	2.81	3.36	23.38	75.49	6.29
2020	269.91	16.19	10.80	11.25	6.32	2.70	3.44	23.61	74.31	6.19
2021	258.67	15.52	10.35	11.25	6.05	2.59	3.53	23.85	73.13	6.09
2022	247.42	14.85	9.90	11.25	5.79	2.47	3.62	24.09	71.96	6.00
2023	236.18	14.17	9.45	11.25	5.53	2.36	3.71	24.33	70.79	5.90
2024	224.93	13.50	9.00	11.25	5.26	2.25	3.80	24.57	69.63	5.80
2025	213.68	12.82	8.55	11.25	5.00	2.14	3.90	24.82	68.47	5.71
2026	202.44	12.15	8.10	11.25	4.74	2.02	3.99	25.07	67.31	5.61
2027	191.19	11.47	7.65	11.25	4.47	1.91	4.09	25.32	66.16	5.51
2028	179.94	10.80	7.20	11.25	4.21	1.80	4.20	25.57	65.02	5.42
2029	168.70	10.12	6.75	11.25	3.95	1.69	4.30	25.83	63.88	5.32
2030	157.45	9.45	6.30	11.25	3.68	1.57	4.41	26.09	62.74	5.23
2031	146.20	8.77	5.85	11.25	3.42	1.46	4.52	26.35	61.61	5.13
2032	134.96	8.10	5.40	11.25	3.16	1.35	4.63	26.61	60.49	5.04
2033	123.71	7.42	4.95	11.25	2.89	1.24	4.75	26.88	59.37	4.95
2034	112.46	6.75	4.50	11.25	2.63	1.12	4.87	27.14	58.26	4.85
2035	101.22	6.07	4.05	11.25	2.37	1.01	4.99	27.42	57.15	4.76
2036	89.97	5.40	3.60	11.25	2.11	0.90	5.11	27.69	56.05	4.67
2037	78.73	4.72	3.15	11.25	1.84	0.79	5.24	27.97	54.95	4.58
2038	67.48	4.05	2.70	11.25	1.58	0.67	5.37	28.25	53.86	4.49

CT2010
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 300	Income Tax Rate:	39.0%	
In Service Date	2010	Fixed O&M in $/kw-yr (1998$)	$ 2.00	
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%	
Equity Percentage	50.0%	General Inflation Rate	2.5%	
Debt Percentage	50.0%			
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000	
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30	(1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%	

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$87.15	$84.77	$82.86	$81.37	$80.23	$77.59	/kw-yr.
Levelized Annual Revenue Required:	$ 7.26	$ 7.06	$ 6.91	$ 6.78	$ 6.69	$ 6.47	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2010	403.47	24.21	16.14	11.53	9.44	4.03	2.69	21.38	89.42	7.45
2011	391.94	23.52	15.68	11.53	9.17	3.92	2.76	21.59	88.16	7.35
2012	380.41	22.82	15.22	11.53	8.90	3.80	2.83	21.81	86.91	7.24
2013	368.88	22.13	14.76	11.53	8.63	3.69	2.90	22.03	85.66	7.14
2014	357.36	21.44	14.29	11.53	8.36	3.57	2.97	22.25	84.41	7.03
2015	345.83	20.75	13.83	11.53	8.09	3.46	3.04	22.47	83.17	6.93
2016	334.30	20.06	13.37	11.53	7.82	3.34	3.12	22.69	81.94	6.83
2017	322.77	19.37	12.91	11.53	7.55	3.23	3.20	22.92	80.70	6.73
2018	311.25	18.67	12.45	11.53	7.28	3.11	3.28	23.15	79.47	6.62
2019	299.72	17.98	11.99	11.53	7.01	3.00	3.36	23.38	78.25	6.52
2020	288.19	17.29	11.53	11.53	6.74	2.88	3.44	23.61	77.03	6.42
2021	276.66	16.60	11.07	11.53	6.47	2.77	3.53	23.85	75.81	6.32
2022	265.14	15.91	10.61	11.53	6.20	2.65	3.62	24.09	74.60	6.22
2023	253.61	15.22	10.14	11.53	5.93	2.54	3.71	24.33	73.40	6.12
2024	242.08	14.52	9.68	11.53	5.66	2.42	3.80	24.57	72.20	6.02
2025	230.55	13.83	9.22	11.53	5.39	2.31	3.90	24.82	71.00	5.92
2026	219.02	13.14	8.76	11.53	5.13	2.19	3.99	25.07	69.81	5.82
2027	207.50	12.45	8.30	11.53	4.86	2.07	4.09	25.32	68.62	5.72
2028	195.97	11.76	7.84	11.53	4.59	1.96	4.20	25.57	67.44	5.62
2029	184.44	11.07	7.38	11.53	4.32	1.84	4.30	25.83	66.26	5.52
2030	172.91	10.37	6.92	11.53	4.05	1.73	4.41	26.09	65.09	5.42
2031	161.39	9.68	6.46	11.53	3.78	1.61	4.52	26.35	63.92	5.33
2032	149.86	8.99	5.99	11.53	3.51	1.50	4.63	26.61	62.76	5.23
2033	138.33	8.30	5.53	11.53	3.24	1.38	4.75	26.88	61.60	5.13
2034	126.80	7.61	5.07	11.53	2.97	1.27	4.87	27.14	60.45	5.04
2035	115.28	6.92	4.61	11.53	2.70	1.15	4.99	27.42	59.31	4.94
2036	103.75	6.22	4.15	11.53	2.43	1.04	5.11	27.69	58.17	4.85
2037	92.22	5.53	3.69	11.53	2.16	0.92	5.24	27.97	57.04	4.75
2038	80.69	4.84	3.23	11.53	1.89	0.81	5.37	28.25	55.91	4.66
2039	69.17	4.15	2.77	11.53	1.62	0.69	5.50	28.53	54.79	4.57

CC2005
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 450	Income Tax Rate:	39.0%
In Service Date	2005	Fixed O&M in $/kw-yr (1998$)	$ 6.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$111.12	$108.00	$105.50	$103.55	$102.07	$98.69	/kw-yr.
Levelized Annual Revenue Required:	$ 9.26	$ 9.00	$ 8.79	$ 8.63	$ 8.51	$ 8.22	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transport	Annual Revenue Required	Monthly Revenue Required
2005	534.91	32.09	21.40	15.28	12.52	5.35	7.13	20.34	114.11	9.51
2006	519.63	31.18	20.79	15.28	12.16	5.20	7.31	20.54	112.46	9.37
2007	504.34	30.26	20.17	15.28	11.80	5.04	7.49	20.75	110.80	9.23
2008	489.06	29.34	19.56	15.28	11.44	4.89	7.68	20.96	109.16	9.10
2009	473.78	28.43	18.95	15.28	11.09	4.74	7.87	21.17	107.52	8.96
2010	458.49	27.51	18.34	15.28	10.73	4.58	8.07	21.38	105.89	8.82
2011	443.21	26.59	17.73	15.28	10.37	4.43	8.27	21.59	104.27	8.69
2012	427.93	25.68	17.12	15.28	10.01	4.28	8.48	21.81	102.65	8.55
2013	412.64	24.76	16.51	15.28	9.66	4.13	8.69	22.03	101.05	8.42
2014	397.36	23.84	15.89	15.28	9.30	3.97	8.91	22.25	99.44	8.29
2015	382.08	22.92	15.28	15.28	8.94	3.82	9.13	22.47	97.85	8.15
2016	366.79	22.01	14.67	15.28	8.58	3.67	9.36	22.69	96.26	8.02
2017	351.51	21.09	14.06	15.28	8.23	3.52	9.59	22.92	94.69	7.89
2018	336.23	20.17	13.45	15.28	7.87	3.36	9.83	23.15	93.12	7.76
2019	320.95	19.26	12.84	15.28	7.51	3.21	10.08	23.38	91.56	7.63
2020	305.66	18.34	12.23	15.28	7.15	3.06	10.33	23.61	90.00	7.50
2021	290.38	17.42	11.62	15.28	6.79	2.90	10.59	23.85	88.46	7.37
2022	275.10	16.51	11.00	15.28	6.44	2.75	10.85	24.09	86.92	7.24
2023	259.81	15.59	10.39	15.28	6.08	2.60	11.12	24.33	85.40	7.12
2024	244.53	14.67	9.78	15.28	5.72	2.45	11.40	24.57	83.88	6.99
2025	229.25	13.75	9.17	15.28	5.36	2.29	11.69	24.82	82.37	6.86
2026	213.96	12.84	8.56	15.28	5.01	2.14	11.98	25.07	80.87	6.74
2027	198.68	11.92	7.95	15.28	4.65	1.99	12.28	25.32	79.38	6.62
2028	183.40	11.00	7.34	15.28	4.29	1.83	12.59	25.57	77.91	6.49
2029	168.11	10.09	6.72	15.28	3.93	1.68	12.90	25.83	76.44	6.37
2030	152.83	9.17	6.11	15.28	3.58	1.53	13.22	26.09	74.98	6.25
2031	137.55	8.25	5.50	15.28	3.22	1.38	13.55	26.35	73.53	6.13
2032	122.26	7.34	4.89	15.28	2.86	1.22	13.89	26.61	72.09	6.01
2033	106.98	6.42	4.28	15.28	2.50	1.07	14.24	26.88	70.67	5.89
2034	91.70	5.50	3.67	15.28	2.15	0.92	14.60	27.14	69.26	5.77

CC2010
Revenue Requirement

Capital Cost - $/kw (1998$)	$ 450	Income Tax Rate:	39.0%
In Service Date	2010	Fixed O&M in $/kw-yr (1998$)	$ 6.00
Service Life in Years	35	Property Tax Rate - %/yr.	1.0%
Equity Percentage	50.0%	General Inflation Rate	2.5%
Debt Percentage	50.0%		
Return on Equity	12.0%	Gas Transportation - Btu/day	170,000
Debt Cost	8.0%	Gas Trns. Rate - $/MMBtu/mo.	$ 9.30 (1998$)
Blended Capital/Discount Rate	10.0%	Gas Trns. Inflation Rate	1.0%

	5 yr.	10 yr.	15 yr.	20 yr.	25 yr.	30 Yr.	
Levelized Annual Revenue Required:	$124.06	$120.49	$117.64	$115.41	$113.72	$109.92	/kw-yr.
Levelized Annual Revenue Required:	$ 10.34	$ 10.04	$ 9.80	$ 9.62	$ 9.48	$ 9.16	/kw-mo.

	Net Plt	ROE	Debt	Depr	Inc Tx	Prop Tax	F-O&M	Gas Transprt	Annual Revenue Required	Monthly Revenue Required
2010	605.20	36.31	24.21	17.29	14.16	6.05	8.07	21.38	127.47	10.62
2011	587.91	35.27	23.52	17.29	13.76	5.88	8.27	21.59	125.58	10.47
2012	570.62	34.24	22.82	17.29	13.35	5.71	8.48	21.81	123.70	10.31
2013	553.33	33.20	22.13	17.29	12.95	5.53	8.69	22.03	121.82	10.15
2014	536.03	32.16	21.44	17.29	12.54	5.36	8.91	22.25	119.95	10.00
2015	518.74	31.12	20.75	17.29	12.14	5.19	9.13	22.47	118.09	9.84
2016	501.45	30.09	20.06	17.29	11.73	5.01	9.36	22.69	116.24	9.69
2017	484.16	29.05	19.37	17.29	11.33	4.84	9.59	22.92	114.39	9.53
2018	466.87	28.01	18.67	17.29	10.92	4.67	9.83	23.15	112.55	9.38
2019	449.58	26.97	17.98	17.29	10.52	4.50	10.08	23.38	110.72	9.23
2020	432.29	25.94	17.29	17.29	10.12	4.32	10.33	23.61	108.90	9.08
2021	414.99	24.90	16.60	17.29	9.71	4.15	10.59	23.85	107.09	8.92
2022	397.70	23.86	15.91	17.29	9.31	3.98	10.85	24.09	105.29	8.77
2023	380.41	22.82	15.22	17.29	8.90	3.80	11.12	24.33	103.49	8.62
2024	363.12	21.79	14.52	17.29	8.50	3.63	11.40	24.57	101.71	8.48
2025	345.83	20.75	13.83	17.29	8.09	3.46	11.69	24.82	99.93	8.33
2026	328.54	19.71	13.14	17.29	7.69	3.29	11.98	25.07	98.16	8.18
2027	311.25	18.67	12.45	17.29	7.28	3.11	12.28	25.32	96.41	8.03
2028	293.95	17.64	11.76	17.29	6.88	2.94	12.59	25.57	94.66	7.89
2029	276.66	16.60	11.07	17.29	6.47	2.77	12.90	25.83	92.93	7.74
2030	259.37	15.56	10.37	17.29	6.07	2.59	13.22	26.09	91.20	7.60
2031	242.08	14.52	9.68	17.29	5.66	2.42	13.55	26.35	89.48	7.46
2032	224.79	13.49	8.99	17.29	5.26	2.25	13.89	26.61	87.78	7.31
2033	207.50	12.45	8.30	17.29	4.86	2.07	14.24	26.88	86.09	7.17
2034	190.21	11.41	7.61	17.29	4.45	1.90	14.60	27.14	84.40	7.03
2035	172.91	10.37	6.92	17.29	4.05	1.73	14.96	27.42	82.73	6.89
2036	155.62	9.34	6.22	17.29	3.64	1.56	15.33	27.69	81.08	6.76
2037	138.33	8.30	5.53	17.29	3.24	1.38	15.72	27.97	79.43	6.62
2038	121.04	7.26	4.84	17.29	2.83	1.21	16.11	28.25	77.80	6.48
2039	103.75	6.22	4.15	17.29	2.43	1.04	16.51	28.53	76.17	6.35

MPS and Empire
Stand Alone Analysis
Incremental Capacity and Total Energy
Cost Comparison
$x1,000

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
MPS STAND ALONE											
Combined Cycle Expansion Plan											
Incr. Capacity Cost	(216)	(3,902)	(4,478)	(827)	36,428	63,858	67,323	70,962	74,804	78,566	382,520
Total Energy Cost	91,509	86,275	90,933	100,187	101,560	105,471	104,614	119,372	131,352	144,356	1,075,628
Total Cost - Actual $	91,293	82,373	86,456	99,360	137,988	169,329	171,937	190,334	206,156	222,922	1,458,147
Net Present Value of 10 Yr. Cost	815,551										
Combustion Turbine Expansion Plan											
Incr. Capacity Cost	(216)	(3,902)	(4,478)	(827)	26,618	47,237	51,038	55,012	59,188	63,284	292,956
Total Energy Cost	91,509	86,275	90,933	100,187	115,511	133,287	137,266	150,501	156,579	162,992	1,225,039
Total Cost - Actual $	91,293	82,373	86,456	99,360	142,129	180,524	188,305	205,513	215,767	226,276	1,517,995
Net Present Value of 10 Yr. Cost	845,291										
EDE STAND ALONE											
Combined Cycle Expansion Plan											
Incr. Capacity Cost	(3,843)	(4,738)	(3,308)	(1,815)	(258)	1,126	2,643	4,399	5,973	21,586	21,766
Total Energy Cost	72,526	78,632	83,105	88,669	93,964	103,208	106,345	114,035	118,898	123,319	982,699
Total Cost - Actual $	68,683	73,893	79,797	86,853	93,706	104,335	108,988	118,434	124,871	144,905	1,004,465
Net Present Value of 10 Yr. Cost	579,864										
Combustion Turbine Expansion Plan											
Incr. Capacity Cost	(3,843)	(4,738)	(3,308)	(1,815)	(258)	1,126	2,643	4,399	5,973	17,080	17,260
Total Energy Cost	72,525	78,628	83,074	88,630	93,894	103,141	106,384	114,002	118,884	124,156	983,318
Total Cost - Actual $	68,682	73,889	79,766	86,815	93,636	104,267	109,028	118,401	124,857	141,236	1,000,577
Net Present Value of 10 Yr. Cost	578,313										

Asbury Operating Enhancements

1. Asbury Heat Rate Improvement

   Modest improvements in the net heat rate for Asbury #1 are projected through operational improvements in the following areas:

   - Implement an aggressive preventive maintenance program.
   - Improve boiler efficiency by improving lower furnace heat absorption, and reducing exit gas temperature and stack losses.
   - Reduce auxiliary power use through improve operating procedures.

2. Asbury Forced Outage Rate Improvement

   Modest improvements in the forced outage rate for Asbury #1 are projected by the implementation of an aggressive preventive maintenance program.

MPS/EDE Combined System
Incremental Capacity and Total Energy
Cost Comparison
$x1,000

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Combined Cycle Expansion Plan											
Incr. Capacity Cost	(5,311)	(9,985)	(9,316)	(4,204)	34,340	63,188	68,303	73,412	78,581	97,900	386,907
Total Energy Cost	157,290	154,150	162,180	174,216	177,568	187,480	189,651	212,205	237,463	250,523	1,902,726
Total Cost-Actual $	151,980	144,165	152,864	170,011	211,908	250,667	257,953	285,617	316,044	348,423	2,289,633
NPV of 2001 - 2010 Costs	1,295,329										
Combustion Turbine Expansion Plan											
MPS + EDE - CT Expansion											
Incr. Capacity Cost	(5,311)	(9,985)	(9,316)	(4,204)	24,530	46,567	52,017	57,462	62,966	77,069	291,794
Total Energy Cost	157,290	154,150	162,180	174,216	196,846	223,663	230,168	251,513	269,287	280,620	2,099,933
Total Cost	151,980	144,165	152,864	170,011	221,375	270,230	282,185	308,975	332,253	357,689	2,391,726
NPV of 2001 - 2010 Costs	1,346,028										

MPS/EDE Merger
Human Resource Savings

	Number	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
EnergyPower Supply	1	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000
Planning Analysts	2	78,800	78,800	78,800	78,800	78,800	78,800	78,800	78,800	78,800	78,800
Fuel Contracts Coodinator	1	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000
Admin Support	1	36,000	36,000	36,000	36,000	36,000	36,000	36,000	36,000	36,000	36,000
Plant Personnel	4	226,000	226,000	226,000	226,000	226,000	226,000	226,000	226,000	226,000	226,000
Manager, Bulk Power Dispatch	1	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000
Life Extension Manager	1	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
Staff Engineer	1	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000	48,000
Power Dispatcher	2	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000	120,000
	14										
Total Annual Cost Reduction - 1999$		941,800	941,800	941,800	941,800	941,800	941,800	941,800	941,800	941,800	941,800
Total Annual Cost Reduction - Actual $		989,479	1,014,216	1,039,571	1,065,560	1,092,199	1,119,504	1,147,492	1,176,179	1,205,584	1,235,723

2001-2010 Total Cost Reduction -
Actual $ 11,086 $x1,000

EDE - MPS ELECTRIC ALLOCATIONS AGREEMENT

This Electric Allocations Agreement (Allocations Agreement) is in regard to the Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU) and Empire District Electric (EDE).

ARTICLE 1 - TERM OF AGREEMENT

1.01 This EDE-MPS Allocations Agreement shall become effective at the closing of the Merger, or such later date as may be fixed by any required regulatory acceptance.

1.02 This EDE - MPS Allocations Agreement shall continue from year-to-year thereafter until terminated by the Effective Time of Retail Competition in Missouri.

ARTICLE II - DEFINITIONS

2.01 Generation Dispatch & Energy Trading shall be a center operated by UCU for the optimal utilization of system power resources for the supply of power and energy for the Company.

2.02 Division shall be MPS and/or EDE.

2.03 Economic Dispatch shall be the distribution of total power resource requirements among alternative sources for system economy with due consideration of system security.

ARTICLE III - PURPOSE

3.01 Purpose of This Agreement
The purpose of the EDE - MPS Allocations Agreement is to provide the basis for the allocation of generation and purchased power resources and costs under the operation of UCU to achieve optimal economies consistent with reliable electric service and reasonable utilization of natural resources; and to establish the basis for capacity commitments within the Company.

ARTICLE IV - ALLOCATIONS

4.01 Planning and Authorization of Generation Capacity

For planning purposes, UCU shall coordinate each Division's forecast of System Capacity to meet the overall System Capacity Responsibility and Capacity Margin.

4.02 Capacity Margin Requirements
Capacity Margin requirements for both MPS and EDE shall be in accordance with the Southwest Power Pool (SPP) criteria for reserve planning.

4.03 Assignments of Existing Generation Capacity and Capacity Costs to Divisions
Each Division shall have assigned to it such generating capacity and associated costs as were owned or contracted for by it prior to the closing of the merger to supply its System Peak Responsibility.

4.04 Allocation of New Generation Capacity to Divisions
Prior to June 1 each year, new generation capacity owned or contracted for by UCU shall be allocated in such a way as to equalize on a pro-rata basis any capacity in excess of the respective reserve requirements of each Division. The capacity reserve margin is calculated by the following.

a The capacity sum is the assigned existing capacity plus allocated new capacity;
b The ratio is the Division capacity sum divided by the non-coincident peak demand of the Division; and
c The capacity reserve margin is the ratio minus 1

4.05 Allocation of New Generation Capacity Costs to Divisions
Unless otherwise specified, the cost of all new generation capacity owned or contracted for by MPS shall be allocated in such a way as to equalize the costs per kilowatt of new generation capacity across the Company. The exceptions are listed below.

a If new generation capacity is built in such a way that facilities use existing generation or generation sites assigned to a Division under 4.03, then UCU shall obtain estimates of the cost savings from the shared facilities from at least three outside sources;
b The cost savings attributable to shared facilities will be the average of the estimates obtained from outside sources.
c The estimated cost savings will be credited as a decrease in allocated costs to the Division with the shared facilities, and will be debited as an increase in allocated costs to other Divisions.

4.06 Economic Dispatch
The UCU Dispatch Center shall perform Economic Dispatch by scheduling energy output of the generation resources to obtain the lowest cost of energy for serving System demand consistent with operating and security constraints,

including voltage control, stability, loading of facilities, operating guides, interconnection contracts fuel commitments, environmental requirements and continuity of service to customers.

4.07 Exchanges With Other Utilities
The UCU Dispatch Center shall coordinate and direct off-system purchases and sales of energy necessary to meet system requirements or to improve system economy.

4.08 Allocation of Energy Costs
In order to maximize the economic benefits available to UCU, UCU will dispatch the power supply resources of MPS and EDE in a centralized manner (centralized dispatch). To accomplish this, energy costs for EDE and MPS resulting from centralized dispatch of the combined generating units and purchased power resources will be determined in the following manner:

a. Accounting information for energy costs incurred each month will be maintained separately for each Division.

    1. Energy costs from generation resources assigned to each division under 4.03 will be assigned to that same Division.
    2. Energy costs from generation resources allocated to each Division under 4.04 will be allocated to that same Division using the same allocation factor used for allocating new generation.
    3. Energy costs from other generation resources outside the combined centers system will be allocated to each Division on equal dollars per megawatt-hour basis.

b. The RealTime® production cost model will be used to simulate monthly fuel and interchange energy costs using data based on actual operating statistics for the subject month. Monthly operating statistics will include data for all power resources which were utilized plus historical and anticipated performance characteristics of power resources not utilized. Generating unit operating parameters used in the RealTime® model will be established using actual hourly generation values. These operating parameters will then be adjusted, if necessary, until RealTime® model output statistics for the joint dispatch reflect actual production data (i.e., fuel costs, heat rates, maintenance outages, etc.) for the subject month. Once the model is calibrated to the actual generation parameters, it will be permitted to re-dispatch the generating resources along with actual interchange transactions that occurred during the month in order to meet the actual joint hourly load profile of the Company.

c. The MPS and EDE systems will then be modeled on an "own load" re-dispatch basis for the subject month. Generating unit and interchange parameters, as developed in the joint dispatch model (step b. above), will be used as input data for the stand alone production cost simulations to be performed for each Company. In addition, own load re-dispatch will reflect applicable pre-merger operating practices and conditions.

d. Each Division's incremental or decremental energy cost for the month will be determined as the difference between actual costs (step a. above) and the modeled cost (step c. above). The sum of the incremental costs and the decremental costs shall represent the cost savings achieved through centralized dispatch. The stand alone costs (step c. above) of EDE will then be reduced by the total of the cost savings. The result will be the adjusted energy cost for the month for EDE.

e. The Divisions shall reconcile energy costs each month. The Division(s) which incurred additional costs during the month for the benefit of the other Division(s) shall receive from the benefiting Division(s) a credit equal to the difference between the costs incurred for the month (step a. above) and the adjusted energy cost (step d. above).

ARTICLE V - CENTRAL DISPATCH CENTER

5.01 Central Power Dispatch Center
UCU shall provide and operate a Central Power Dispatch Center (CPDC) adequately equipped and staffed to meet the requirements for efficient, economical and reliable operation as contemplated by this Allocations Agreement.

5.02 Communications and Other Facilities
The CDPC shall provide communications and other facilities necessary for:

a. the metering and control of the generating and transmission facilities.

b. the dispatch of electric power and energy; and

c. such other purposes as may be necessary for optimum operation of the system and the implementation of this Allocations Agreement.

ARTICLE VI - GENERAL

6.01 Regulatory Authorization
This Allocations Agreement is subject to regulatory approval by the Missouri Public Service Commission. UCU shall seek all necessary regulatory authorizations for this Allocations Agreement.

6.02 Effect on Other Agreements

This Allocations Agreement shall not modify the obligation of other agreements between the Divisions and others not parties to this Allocations Agreement.

ALLOCATIONS AGREEMENT

EXAMPLE: COST ALLOCATIONS

	MPS (000s)	EDE (000s)	TOTAL (000s)
1. Actual fuel and net interchange for the month.	$7,500	$2,000	$9,500
2. Production model of the joint control area operation to reflect actual operating parameters and costs.			$9,500
3. Production model of the joint control area operation to reflect alone basis by using model data in Step 2 above.	$8,300	$1,800	$10,100
4. Determination of incremental/decremental cost for the month. (Step 1 - Step 3)	-$800	$200	-$600
5. Determination of joint dispatch savings. (Step 4)			$600
6. Savings available to reduce EDE's stand alone fuel costs.		$600	$600
7. Adjusted fuel and net interchange for the month. (Step 3 - Step 6)	$8,300	$1,200	$9,500

MPS + EDE
Power Supply Synergies
Actual Dollars

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Total Synergies											
Capacity	1,252	1,345	1,530	1,563	1,830	1,797	1,664	1,949	2,196	(2,254)	12,872
On System Energy	3,705	3,032	3,458	4,200	3,966	4,706	4,237	4,804	3,721	3,972	39,802
Off System Sales	3,038	7,720	8,370	10,400	13,920	16,426	17,110	16,365	9,052	14,016	116,417
Total - Actual Dollars	7,995	12,097	13,359	16,163	19,717	22,929	23,011	23,119	14,969	15,734	169,092
MPS											
Capacity	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
On System Energy	-	-	-	-	-	-	-	-	-	-	-
Off System Sales	-	-	-	-	-	-	-	-	-	-	-
Total - Actual Dollars	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
EDE											
Capacity	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
On System Energy	3,705	3,032	3,458	4,200	3,966	4,706	4,237	4,804	3,721	3,972	39,802
Off System Sales	3,038	7,720	8,370	10,400	13,920	16,426	17,110	16,365	9,052	14,016	116,417
Total - Actual Dollars	7,369	11,424	12,593	15,382	18,801	22,031	22,179	22,144	13,871	16,861	162,656

Power Supply Synergy Comparison
Current vs. Original Analysis
$x1,000

		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL
Original Analysis												
Capacity		7,745	6,237	8,491	8,752	9,527	5,998	13,575	13,915	14,262	14,619	103,121
Energy		21,273	23,417	16,530	18,315	16,901	18,933	12,060	12,362	12,671	12,988	165,449
Off system sales		5,384	5,519	5,657	5,798	5,943	6,092	6,244	6,400	6,560	6,724	60,324
	Total	34,402	35,173	30,678	32,866	32,371	31,023	31,880	32,677	33,494	34,331	328,895
Current Analysis												
Capacity		1,252	1,345	1,530	1,563	1,830	1,797	1,664	1,949	2,196	(2,254)	12,872
Energy		3,705	3,032	3,458	4,200	3,966	4,706	4,237	4,804	3,721	3,972	39,802
Off system sales		3,038	7,720	8,370	10,400	13,920	16,426	17,110	16,365	9,052	14,016	116,417
	Total	7,995	12,097	13,358	16,164	19,716	22,929	23,011	23,118	14,969	15,734	169,091
Change												
Capacity		(6,493)	(4,892)	(6,961)	(7,189)	(7,697)	(4,201)	(11,911)	(11,966)	(12,066)	(16,873)	(90,249)
Energy		(17,568)	(20,385)	(13,072)	(14,115)	(12,934)	(14,226)	(7,823)	(7,558)	(8,950)	(9,016)	(125,647)
Off system sales		(2,346)	2,201	2,713	4,602	7,976	10,334	10,866	9,965	2,492	7,291	56,093
	Total	(26,407)	(23,076)	(17,320)	(16,702)	(12,655)	(8,094)	(8,868)	(9,559)	(18,525)	(18,597)	(159,803)

Impact of EDE Merger
on
MPS and SJLP Power Supply Synergies

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
MPS Power Supply Synergies - MPS/EDE Merger											
Capacity	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
On System Energy	-	-	-	-	-	-	-	-	-	-	-
Off System Sales	-	-	-	-	-	-	-	-	-	-	-
Total - 1999 Dollars	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
EDE Power Supply Synergies - MPS/EDE Merger											
Capacity	626	672	765	781	915	899	832	975	1,098	(1,127)	6,436
On System Energy	3,705	3,032	3,458	4,200	3,966	4,706	4,237	4,804	3,721	3,972	39,802
Off System Sales	3,038	7,720	8,370	10,400	13,920	16,426	17,110	16,365	9,052	14,016	116,417
Total - 1999 Dollars	7,369	11,424	12,593	15,382	18,801	22,031	22,179	22,144	13,871	16,861	162,656
MPS Power Supply Synergies - MPS/SJLP/EDE Merger											
Capacity	489	573	638	651	665	599	718	850	877	(2,729)	3,330
On System Energy	-	0	-	0	0	-	-	-	0	0	0
Off System Sales	-	-	(0)	-	0	-	0	-	(0)	-	0
Total - 1999 Dollars	489	573	638	651	665	599	718	850	877	(2,729)	3,330
EDE Power Supply Synergies - MPS/SJLP/EDE Merger											
Capacity	489	573	638	651	665	599	718	850	877	(2,729)	3,330
On System Energy	4,078	3,326	4,435	4,824	5,472	5,502	5,488	5,542	4,838	5,231	48,736
Off System Sales	5,129	9,788	12,228	13,454	18,419	15,687	17,462	15,080	9,259	17,638	134,144
Total - 1999 Dollars	9,697	13,687	17,300	18,930	24,555	21,787	23,668	21,471	14,974	20,140	186,210
Change in MPS Power Supply Synergies due to Merger with SJLP											
Capacity	(137)	(99)	(128)	(130)	(250)	(300)	(114)	(125)	(221)	(1,602)	(3,106)
On System Energy	-	0	-	0	0	-	-	-	0	0	0
Off System Sales	-	-	(0)	-	0	-	0	-	(0)	-	0
Total - 1999 Dollars	(137)	(99)	(128)	(130)	(250)	(300)	(114)	(125)	(221)	(1,602)	(3,106)
Change inEDE Power Supply Synergies due to Merger with SJLP											
Capacity	(137)	(99)	(128)	(130)	(250)	(300)	(114)	(125)	(221)	(1,602)	(3,106)
On System Energy	373	294	976	624	1,505	795	1,251	738	1,118	1,259	8,934
Off System Sales	2,091	2,068	3,858	3,054	4,499	(739)	351	(1,286)	207	3,622	17,727
Total - 1999 Dollars	2,328	2,263	4,707	3,548	5,754	(243)	1,488	(673)	1,103	3,279	23,555