Exhibit No.:	
Issues:	Class Cost Of Service & Rate Design; Joint Dispatch Agreement
Witness:	Michael S. Proctor
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Direct Testimony
Case No.:	ER-2001-672
Date Testimony Prepared:	December 6, 2001

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

MICHAEL S. PROCTOR

UTILICORP UNITED, INC.
D/B/A/ MISSOURI PUBLIC SERVICE

CASE NO. ER-2001-672

Jefferson City, Missouri
December 2001

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DIRECT TESTIMONY

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MICHAEL S. PROCTOR

UTILICORP UNITED, INC.

D/B/A MISSOURI PUBLIC SERVICE

CASE NO. ER-2001-672

Q. What is your name and business address?

A. My name is Michael S. Proctor. My business address is 200 Madison St., P.O. Box 360, Jefferson City, Mo. 65102-0360.

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

A. I am employed by the Missouri Public Service Commission (Commission) as Manager of Economic Analysis in the Energy Department.

Q. What is your education background and work experience?

A. I have Bachelors and Masters of Arts Degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. My previous work experience has been as an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1977, I have been on the Staff of the Commission and have presented testimony on various issues related to weather normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. In 1997 and 1998, I served as the Staff Vice Chair of the Market Structure and Market Power working group of the Commission's Task Force on Retail Competition. Since December of 2000, I have served as chairman of the Forward Congestion Markets Subgroup of the Southwest Power Pool's (SPP's) Congestion Management Systems Working Group.

Q. What are your current duties in the energy department as manager of economic analysis?

A. I supervise the Economic Analysis group within the Energy Department. This group is responsible for various issues related to weather normalization of sales, class cost of service and rate design. In addition to my supervisor's role, I have focused my attention on the development and structure of Regional Transmission Organizations (RTOs) for the purpose of increasing efficiency and reliability in the competitive supply of electricity. Because of the restructuring of the electric industry toward the increased competitive supply of electricity, I have also focused on the issue of market power within the electric industry.

RECOMMENDATIONS

Q. In this instant case, what is the purpose of your direct testimony?

A. My direct testimony in this case addresses the issues of class revenue requirements and rate design and the allocation of joint dispatch costs from the combined electricity supply resources of Missouri Public Service (MPS) and St. Joseph Power & Light (SJLP), divisions of UtiliCorp United (UCU).

Q. What are your recommendations with respect to the class revenue requirements and rate design?

A. My recommendation is that any additional revenue requirement resulting from this case be applied as an equal percentage increase to all classes and to all rate components for each rate schedule or tariff. In addition, I am recommending that the

Commission establish an "EO" docket for the purpose of investigating the functional cost components of each rate for MPS and SJLP, as well as for the purpose of investigating the class cost of service and rate design for MPS and SJLP.

Q. What is your recommendation with respect to the allocation of joint dispatch costs?

A. My recommendation is that joint dispatch costs, including off-system purchases of electricity, be allocated between the two divisions based on each division's percent of stand-alone costs – the cost of meeting each division's load requirements from each division's electricity supply resources.

CLASS REVENUE REQUIREMENTS AND RATE DESIGN

Q. What is class cost of service?

A. Class cost of service is an allocation of the Company's approved revenue requirement among the various rate classes. This allocation of costs is based on what is called a class cost of service study in which costs are separated into distinct functional areas to which specific class allocation factors are then applied to determine each class's cost of service. The result is a table such as is shown in Schedule 1 attached to my direct testimony, where each row corresponds to a functional area of cost and each column to a rate class. A description of each functional area appears in the first column of the table in Schedule 1, and the corresponding methods used by the Staff to allocate each functional cost to the classes are listed in the second column. The dollars allocated to each class appear in the columns for each functional cost area. These allocated costs are added together for each class to determine its total cost of service, and this total is compared to the revenues being collected from each class of service through its rates. If the rate revenues are less than the allocated costs, current rates are collecting less from that class than its allocated cost of service, and if rate revenues are greater than the allocated costs, current rates are collecting more from that class than its allocated cost of service. Such imbalances between revenues and allocated costs are an indication that class revenue requirements may need to be shifted from the classes paying above their cost of service to the classes paying below their cost of service.

Q. Has the staff performed a class cost of service study in this case?

A. The Staff has not performed a class cost of service study for the loads, revenues and costs that it is proposing in this case. Instead, Schedule 1 is an update to the Staff's class cost of service study that was submitted in MPS's last Case No. ER-97-394. This update matches the costs, sales and rates approved by the Commission in that case. Therefore, it represents the Staff's allocation of costs that are included in MPS's existing rates. A study by UCU or other interveners to this case would likely have different levels for the functionalized costs and different allocation methods, and such studies would show different levels of costs included in MPS's existing rates.

Q. Why did you not perform a class cost of service study for the loads, revenues and costs proposed in this case?

A. UCU did not have current and reliable load research data that is required to develop the allocation factors necessary to perform a current class cost of service study. Specifically, while the Company has load research data from 1997, this data is based on a sample that dates back to 1990, when the load research meters were first installed. Such a sample is well beyond its useful life for estimating class load shapes.

Q. Does the Staff perform load research studies and gather the data required to develop the allocation factors?

A. No. The investor-owned utilities are responsible for collecting load research data and estimating class loads from this data. The most recent load research data available for MPS was collected in 1997 from a sample that was over seven years old. The estimates from this data were replete with inconsistencies, and the Company has subsequently updated the sample. It was over a decade before UCU set out meters for a new load research sample. Unfortunately, the new sample data was not available in time for this case.

Q. How often should an electric utility set out a new load research sample?

A. I recommend a completely new sample every five years with annual updates to the existing sample taking place during this five-year cycle.

Q. On what basis did the staff perform its class cost of service study for Case No. ER-97-394?

A. In that case, the Staff used updated sales and customer numbers to "factor up" the allocation factors from the previous Case No. ER-93-37. Schedule 1, attached to my direct testimony, contains the update of that study that conforms to the Commission's Report and Order in Case No. ER-97-394. This revised study shows that, for the rates approved in Case No. ER-97-394, the residential class is contributing less than its cost of service and the other classes are contributing, in varying amounts, more than their cost of service.

Q. Would using the 1997 load research data to perform a class cost of service study be better than updating the class load shapes used in the Case No. ER-93-97?

A. No. The use of the 1997 load research data could grossly misrepresent the actual class load shapes. At least the earlier studies properly represented the class load shapes as they existed at that point in time. The problem with the 1997 load research data is the deterioration of the sample used to represent each class. This occurs as individuals move or change their usage and as companies move, go out of business or change their usage.

In addition to sample deterioration, Staff's detailed review of the 1997 MPS load research data found significant problems with two particular subgroups. First, daily peak loads for Rate 325 of the Large General Service Class appear to be either overestimated for the months of June, August, September and October or significantly underestimated for the remaining months of 1997. This is shown in graphical form on Schedule 2-1, attached to my direct testimony.

Second, loads from Rate 335 of the Large Power Class appear to be overestimated for dates in June when some of the customers from this 100% sampled class were not included. This is shown in graphical form on Schedule 2-2, attached to my direct testimony.

Q. Given the lack of current and reliable load research data for purposes of performing a current class cost of service study, what is the staff's recommendation with respect to the allocation of revenue requirements and rate design for purposes of this case?

A. The Staff is recommending that any increase in revenue requirements allowed by the Commission in this case be allocated to the various rate classes in proportion to the current revenue requirements for each class and that all rate components on existing MPS rate schedules be increased by the same percentage. In essence, this means an equal percentage increase to all classes of service and to all customers served within these classes.

Q. Did you consider any other methods for determining class revenue requirements in this case?

A. Absent a credible class cost of service study, an alternative is to consider how fixed and variable costs are currently included in customer rates and then allocate any increase in variable costs based on the percentage of variable costs in existing rates and any increase in fixed costs based on the percentage of fixed costs in existing rates. The specific application of this methodology to this case would be to allocate the increase in fuel and purchased power expense based on each class' share of kilowatt-hour sales with losses and to allocate the remainder of the increase in proportion to the each class' share of revenue requirements minus fuel and purchased power expense. This approach has been called the "fuel/non-fuel" allocation method.

Q. Why did you reject the fuel/non-fuel method?

A. There are difficulties with the fuel/non-fuel method. Current rates may not correspond to a specific cost allocation, but instead may be based on either a settlement of the parties, or on a Commission order that took into account rate impact. For example, in Schedule 1 it appears that the residential class is below its cost of service and the other classes are above their cost of service. In this instance, if the fuel/non-fuel allocation method were used and it was an accurate representation of cost allocation, the resulting revenue requirements would actually maintain the imbalance shown in the class cost of service study.

In addition, the non-fuel portion of existing rates may not be representative of the functional areas that are major contributors to the increase in fixed cost. The non-fuel component of existing rates represents an overall average mix for production, transmission, distribution, customer and overhead fixed costs, and if the specific increase in fixed costs is significantly different from that mix, the non-fuel component of existing rates will not be an accurate allocation method because the various classes have significantly different allocations for each of these functional areas. For example, the residential class' share of production fixed costs (48%) are significantly less than its share of distribution (65%) or customer related fixed costs (83%).

Q. Even if the fuel/non-fuel is accurate, in this case would the equal percentage increase to each class be preferable to the fuel/non-fuel method?

A. Yes. Over a range of increases, if an equal percentage increase to each class is used, this would tend to narrow the cost-of-service imbalance by shifting more revenue requirement to the residential class than they would receive from the application of the fuel/non-fuel allocation. For this case where there is approximately a $10 million increase from fuel related costs compared to what is currently in rates, this shifting of revenues to the residential class is shown in Schedule 3 attached to my direct testimony.

Q. For this case, did you find that the fuel/non-fuel allocation method tracks cost of service?

A. No. As a general matter, if the utility's fixed costs are growing proportionately in all areas (production, transmission, distribution, customer and overhead) of service, then the fuel/non-fuel allocation method will track increases in the cost of service. However, if certain areas of fixed costs are growing much more rapidly than others, the fuel/non-fuel allocation method will not do a good job of tracking increases in the cost of service. In this case, the primary reason for a rate increase related to fixed costs is the addition of the demand charges associated with the Aries plant. If production capacity costs are a primary driver in the cost increase, then instead of using the non-fuel portion of the current revenues for each class, it would be more appropriate to use the allocation factor for production capacity costs. The Staff uses what it calls a time-of-use (TOU) allocation methods for production capacity and production energy costs. These methods are detailed in Schedule 4 attached to my direct testimony.

Q. What shifts result for the residential class from using an equal percentage increase when TOU allocators represent the increase in total cost of service?

A. Using the Staff's proposed normalized sales for this case, I "factored up" the Staff's time of use (TOU) allocation factors for production capacity and production energy. Schedule 5 shows the shift of revenue requirements to the residential class when compared to using the TOU allocation factors as the basis for allocating the increase in cost of service for this case. Since the TOU allocation factors are less than the residential class' share of current revenues, applying an equal percentage increase will result in shifting additional revenue requirements onto the residential class and will narrow its cost of service imbalance.

Q. What impact does an equal percentage increase have on the non-residential rates?

A. It will result in maintaining the points of rate continuity among the small general service, large general service and large power service customers. By points of rate continuity I mean the combination of size and load factor at which one of two rates becomes less expensive for the customer. If non-equal percentage increases are applied to these three classes of service, then the points of rate continuity will change and a subset of customers will want to move to the cheaper rate. This is called "rate switching." When rate switching occurs, unless an adjustment is made, MPS would under recover its overall revenue requirement. In order to evaluate rate switching, individual customer data is required.

Q. Is there any reason to apply an unequal percentage increase to the rates of the non-residential classes?

A. From Schedule 1, it appears that the large general service customers should receive a lower percentage increase than either the small general service or large power customers. However, I am not recommending that such a shift be made in this case for two reasons. First, the load research data used as the basis for the allocation factors that were updated for this class cost of service study is over a decade old, and while I have some confidence that the load shapes for the residential class have not changed significantly, I do not hold that same level of confidence for differences in load shapes for the various non-residential classes. Second, if unequal percentage increases are applied, it will affect the points of rate continuity between the various rates, and this change cannot easily be quantified.

Q. With respect to the rate design for the non-residential classes, do you have any further recommendations?

A. Yes. My recommendation is that such shifts between non-residential classes be investigated in a separate cost-of-service and rate design docket at a time when data from the new load research sample is available. UCU is in the process of updating the sample that it put in place in September of 2000, and having two years of load research data on which to weather normalize class loads is preferred to a single year. Therefore, I recommend that the Commission open an "EO" docket for MPS and SJLP for the purpose of performing class cost of service studies and rate design. In addition to class cost of service and rate design, this "EO" docket should make a determination of the costs included in rates by functional categories (production, transmission, distribution, and customer). This functionalization of costs in current rates could then be applied in future rate cases and could also be used if legislation mandating retail competition is passed and utilities are subsequently required to unbundle their production and transmission costs.

JOINT DISPATCH AGREEMENT

Q. What is a joint dispatch agreement?

A. A joint dispatch agreement, as that term has been used in cases before this Commission, is a formal agreement by which the methodology is set out for determining the assignments or allocations of: 1) electricity supply resources; 2) profits from off-system sales; and 3) jointly dispatched power supply costs.

Q. Is there a joint dispatch agreement for the MPS and SJLP electricity supply resources?

A. In discussion with UCU, my understanding is that such an agreement does not currently exist. Until January 2001, different dispatchers dispatched the two divisions separately. In January of 2001, a single dispatcher began to dispatch the supply resources of both MPS and SJLP. At that time, the two divisions were not electrically connected by UCU transmission facilities, and the single dispatcher had to purchase transmission whenever resources from one division were used to serve load in the other division. In June of 2001, UCU purchased 150 Megawatts of firm transmission capacity from the Associated Electric Cooperatives, Inc. (AECI) as a contract path to connect the MPS and SJLP control areas. A control area is delineated by interconnection points in the utility's transmission system. The flows at each point of interconnection are telemetered to the dispatcher and it is the dispatcher's responsibility to maintain a specific level of net imports (exports) based on the electricity scheduled into, out of, or through the control area. While the dispatcher no longer needed to purchase transmission access with the purchase of the contract path from AECI, two separate control areas were still operated, and it was still necessary to schedule generation from the exporting division to meet load in the importing division. In August of 2001, UCU received an order from the Federal Energy Regulatory Commission (FERC) that allowed UCU to combine the two control areas into a single control area. This means that the load dispatcher no longer has to balance two separate control areas and no longer has to schedule inter-divisional transfers of electricity.

Q. What is your proposal for a joint dispatch agreement between MPS and SJLP?

A. The details are presented in Schedule 6, which is a proposed Joint Dispatch Agreement (JDA) for MPS and SJLP. The JDA has seven sections: 1) Definitions; 2) Divisional Electricity Supply Resource Specification; 3) Determination and Allocation of Profit Margin from Off-System Sales; 4) Divisional Allocation of Costs from Off-System Purchases; 5) Determination of Energy Transfers Between Divisions; 6) Determination of Stand-Alone Costs for Each Division; and 7) Divisional Allocation of

Monthly Joint Dispatch Costs to Serve Native Load. The sequence of these items in JDA reflects the same sequence in which each element of the JDA must be made for purposes of implementation.

Q. In brief, how are divisional supply resources specified for the two divisions?

A. The existing generation and contract purchases of each of the divisions remain with the division. New generation and/or contract purchases are allocated between the divisions in such a way as to equalize each division's forecasted capacity reserve margin. The forecasted capacity reserve margin is the difference between the designated capacity and the forecasted summer peak load divided by the forecasted summer peak load.

Q. In brief, how are profit margins from off-system sales determined and allocated between the two divisions?

A. Off-system sales have also been called "economy sales" and are the sales of electricity that the utility makes from generation capacity that is not needed to serve its load. Profit margins on off-system sales are determined by subtracting from the revenues received for such sales the incremental cost of supplying the electricity to meet the sales. The incremental cost of supply for off-system sales is the additional out-of-pocket cost incurred to produce the electricity for the off-system sale. Profit margins are allocated between the two divisions in proportion to the total amount of the capacity of each division's supply resources.

Q. In brief, how are off-system purchases allocated between the two divisions?

A. Off-system purchases are purchases of electricity that the utility makes when an off-system purchase is cheaper than the cost of producing that electricity from its own resources; i.e., the off-system purchase is "economic" for the utility. If the off-system purchase is economic for both divisions, then the cost of the off-system purchase is allocated between the two divisions based on the loads of the two divisions. If the off-system purchase is only economic for one of the two divisions, then the cost of that purchase is allocated to that division.

Q. In brief, how are energy transfers between the two divisions determined?

A. With the supply resources and off-system purchases assigned and allocated to each division, the sum of energy produced or purchased by each division must equal the sum of the loads from each division. In a given hour the division that is producing or purchasing more electricity than it needs to meet its own load is transferring that excess energy to the other division.

Q. In brief, how are the stand-alone costs of each division determined?

A. Each hour, the stand-alone costs for the division transferring energy are determined by subtracting the cost of the energy transferred from that division's initial share of joint dispatch cost, where the transferred energy is priced at that division's decremental cost. Decremental cost is the decrease in cost that the transferring division would experience had it <u>not</u> supplied the electricity for the transfer. Each hour, the stand-alone costs for the division receiving the transfer of energy are determined by adding the cost of the energy transferred to that division's initial share of joint dispatch costs, where the transferred energy is priced at that division's incremental cost. Incremental cost is the increase in cost that the recipient division would experience had it supplied the electricity from its own supply resources instead of obtaining it from the transfer. In the case of a transfer, the decremental cost of the division making the transfer must be smaller than the incremental cost of the division receiving the transfer; otherwise the transfer would not be economic. Thus, the sum of the stand-alone costs exceeds the total joint dispatch costs.

Q. In brief, how are the joint dispatch costs allocated to the two divisions?

A. Each division is allocated total joint dispatch costs in proportion to its share of stand-alone costs. In essence, the savings from the joint dispatch is the difference between the sum of the two division's stand-alone costs and the total joint dispatch costs, and each division shares in that savings in proportion to what it would have cost had the joint dispatch of the supply resources not been available.

Q. How was this proposed joint dispatch agreement implemented for purposes of this case?

A. Staff Witness Mr. David Elliott simulated the joint dispatch and the stand-alone dispatches for each division. The joint dispatch costs are $88,998,672. The stand-alone costs at MPS are $75,483,577 and at SJLP are $20,533,341, with a total of $96,016,918. The stand-alone cost for MPS is 78.6% of the total and for SJLP is 21.4% of the total. Allocating 78.6% of joint dispatch costs to MPS results in MPS share of joint dispatch costs of $69,841,907, which is a savings of $5,641,670 when compared to its stand-alone costs.

Q. Are these joint dispatch savings the same type of savings as the joint dispatch savings calculated for the merger case?

A. No. They are not. In the merger case, the major portion of joint dispatch savings were estimated to come from increased profits from expanding off-system sales and decreased costs from expanded levels for off-system purchases. The savings calculated by Mr. Elliott reflect the difference in costs when purchased power is restricted to the test year experience and do not include profits from off-system sales. When the off-system purchases are limited to test year levels, the model will properly reflect the test year, but because the model is limited in its ability to obtain savings from purchasing in the wholesale power markets, it will instead capture greater savings from internal transfers between the two divisions.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In The Matter Of The Tariff Filing Of Missouri Public Service (MPS) A Division Of UtiliCorp United Inc., To Implement A General Rate Increase For Reatil Electric Service Provided To Customers In The Missouri Service Area Of MPS	))))))	Case No. ER-2001-672

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Direct testimony in question and answer form, consisting of 16 pages of Direct testimony to be presented in the above case, that the answers in the foregoing Direct testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 5th day of December, 2001.

Dawn L. Hake
Notary Public

DAWN L. HAKE
Notary Public – State of Missouri
County of Cole
My Commission Expires Jan 9, 2005

My commission expires My Commission Expires Jan 9, 2005

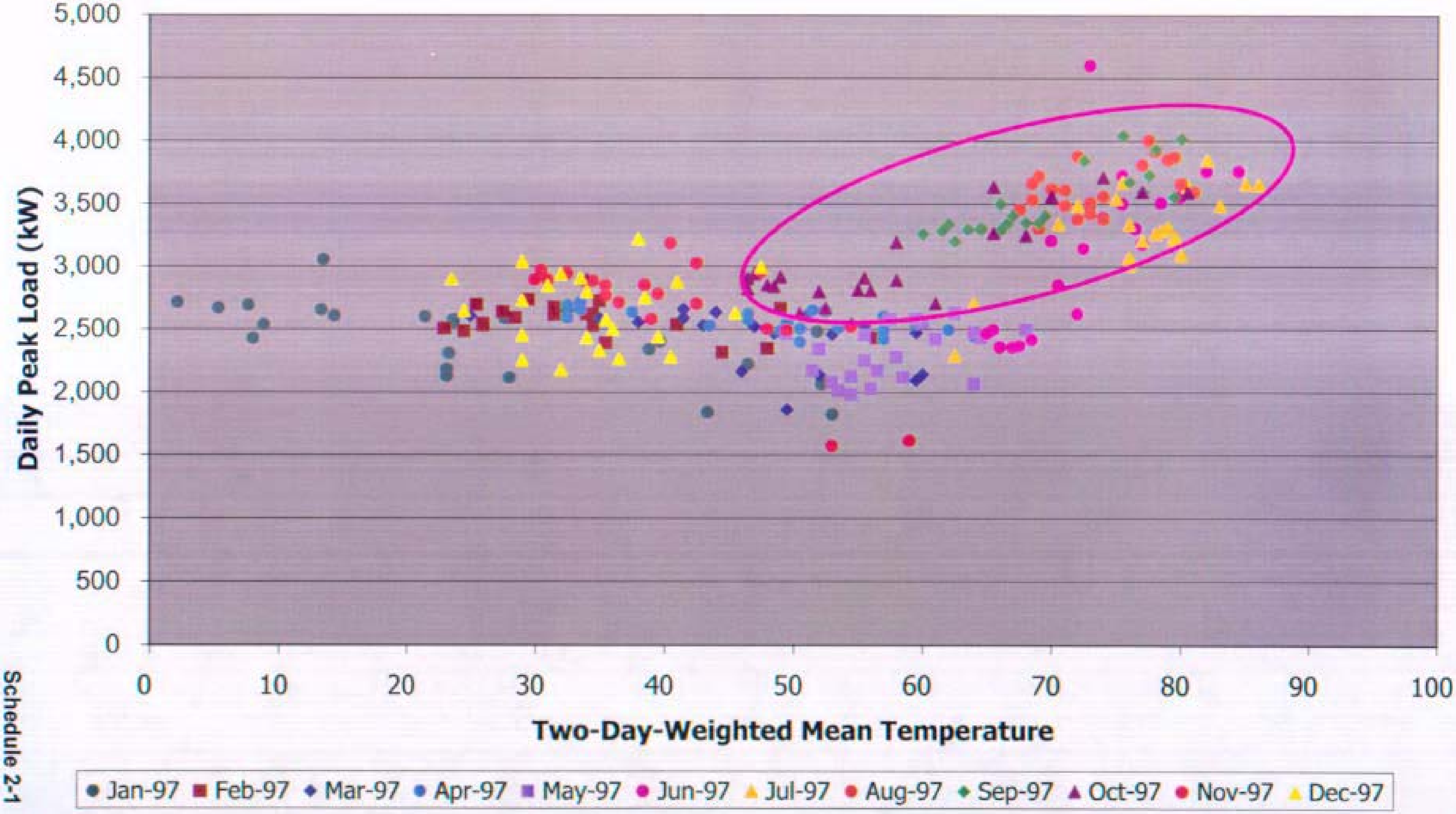
STAFF BASE CLASS COST-OF-SERVICE RESULTS

MISSOURI PUBLIC SERVICE - POST CASE NO. ER-2001-672

FUNCTIONAL CATEGORIES		ALLOCATORS	RES	SGS	LGS	LPR	NON-RES	TOTAL
PRODUCTION	CAPACITY	TOU	$35,136,279	$10,855,168	$9,802,845	$14,831,394	$35,489,407	$70,625,686
PRODUCTION	ENERGY	TOU	$31,503,070	$10,729,799	$9,975,519	$15,744,739	$36,450,057	$67,953,127
TRANSMISSION	CAPACITY	TOU	$10,435,457	$3,223,979	$2,911,440	$4,404,916	$10,540,336	$20,975,792
DISTRIBUTION	SUBSTATIONS	PRI. DMD	$4,778,181	$1,113,770	$814,745	$1,060,178	$2,988,693	$7,766,875
DISTRIBUTION	LINES, POLES, & TRANSFORMERS	PRI. CUST	$6,982,988	$2,790,590	$203,407	$43,086	$3,037,084	$10,020,072
DISTRIBUTION	LINES, POLES, & TRANSFORMERS	SEC. CUST	$9,342,911	$3,731,545	$264,914	$40,139	$4,036,598	$13,379,508
DISTRIBUTION	LINES, POLES, & TRANSFORMERS	PRI. DMD	$9,697,382	$2,260,411	$1,653,536	$2,151,646	$6,065,593	$15,762,975
DISTRIBUTION	LINES, POLES, & TRANSFORMERS	SEC. DMD	$8,185,471	$2,292,289	$1,430,928	$833,328	$4,556,545	$12,742,016
CUSTOMER	SERVICES LINES	SEC. CUST	$4,390,011	$584,368	$21,495	$2,999	$608,863	$4,998,874
CUSTOMER	SERVICES LINES	SEC. DMD	$2,174,091	$478,263	$260,119	$151,353	$889,735	$3,063,826
CUSTOMER	METERS	WGT. CUST	$3,529,101	$899,412	$109,954	$62,108	$1,071,474	$4,600,575
CUSTOMER	METER READING	WGT. CUST.	$1,102,259	$440,493	$32,108	$6,801	$479,401	$1,581,661
CUSTOMER	BILLING & RECORDS	CUST.	$7,984,142	$1,062,795	$39,093	$5,455	$1,107,343	$9,091,485
CUSTOMER	SALES & SERVICES	CUST.	$2,113,028	$281,272	$10,346	$1,444	$293,062	$2,406,090
TOTAL INCLUDING REVENUE OFFSETS			$137,354,370	$40,744,153	$27,530,450	$39,339,587	$107,614,190	$244,968,559
RATE REVENUE			$133,411,101	$41,860,283	$30,296,351	$39,400,822	$111,557,455	$244,968,556
REVENUE DEFICIENCY			$3,943,268	($1,116,130)	($2,765,900)	($61,235)	($3,943,265)	$3
% REVENUE DEFICIENCY			2.96%	-2.67%	-9.13%	-0.16%	-3.53%	0.00%
REVENUE DEFICIENCY AS % OF TOTAL REVENUE REQUIREMENT			1.61%	-0.46%	-1.13%	-0.02%	-1.61%	0.00%

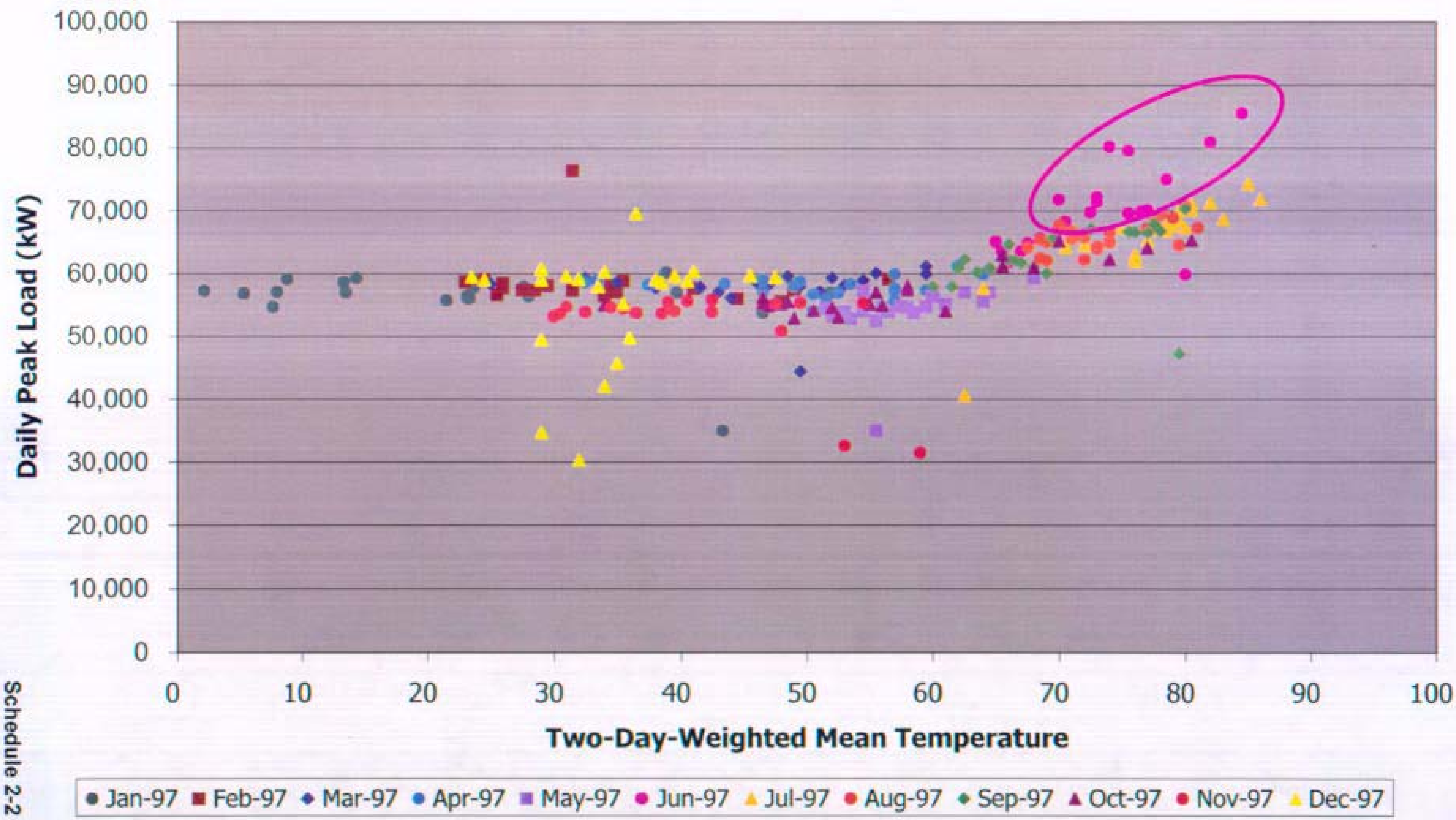
NOTE: ALLOCATED COSTS ARE OFFSET BY ALLOCATED "NON-TARIFF" & "OTHER CLASS" REVENUES

MPS Large General Service (325)
Daily Peak Load vs TDWMT
Weekdays Only



Schedule 2-1

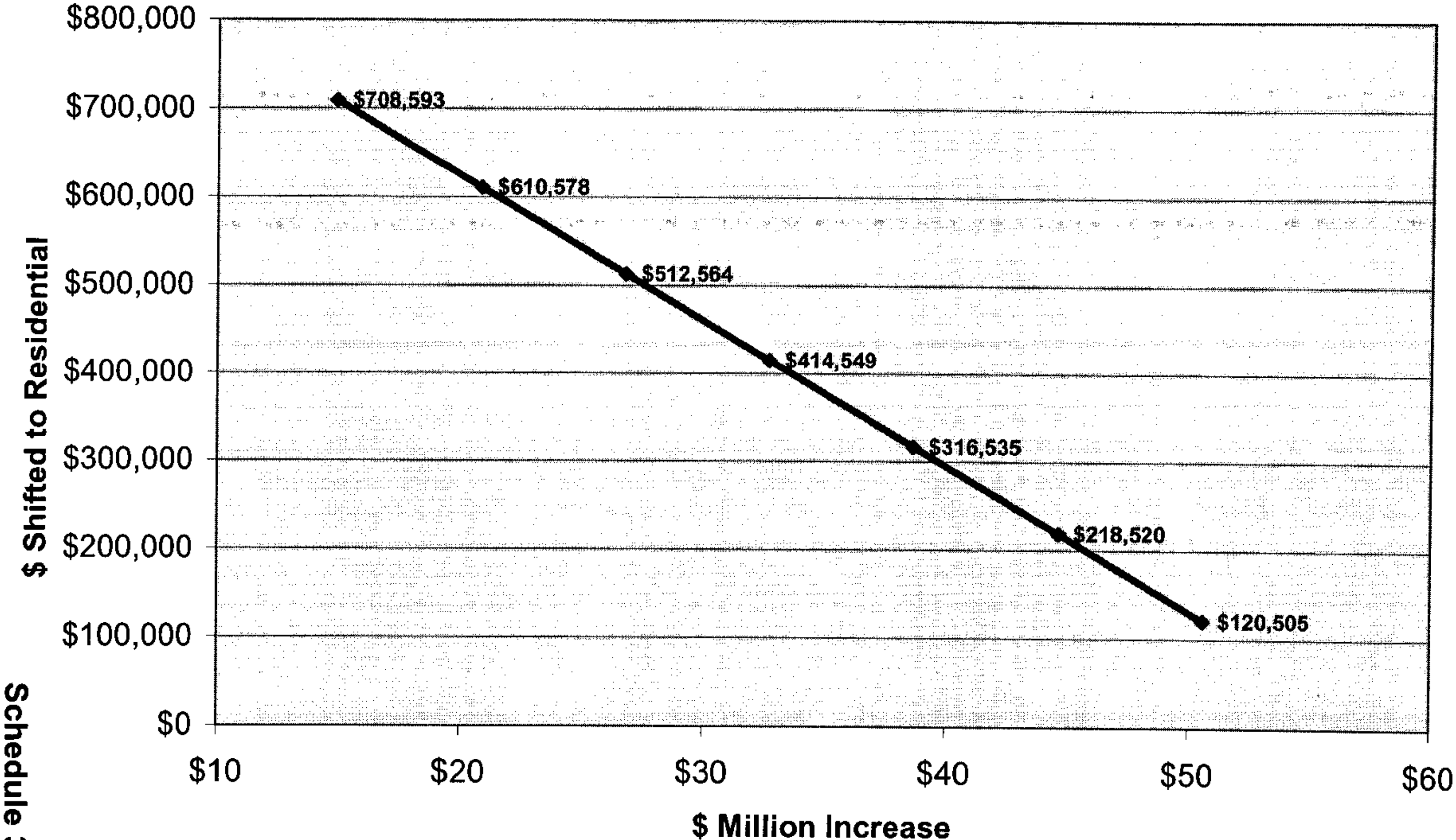
MPS Large Power Service (335)
Daily Peak Load vs TDWMT
Weekdays Only



Schedule 2-2

Revenue Shift to Residential from Equal % Increase

Baseline: Fuel / Non-Fuel Allocation



Schedule 3

TIME-OF-USE ALLOCATION OF ELECTRICITY PRODUCTION COSTS

1. Background

Traditional methods for allocating electricity production cost are based on average cost principles. The production costs of the electric utility are categorized between fixed and variable costs. Variable costs include fuel, fuel handling, and purchased power.[1] All other direct production costs are categorized as fixed, with return on and of the investment in generation plant and demand charges for contract purchases being the two major items of fixed costs.

a) Variable production costs are traditionally allocated to classes of service as an average annual cost. Annual average variable cost is calculated by dividing annual total variable costs by annual sales, including losses to the generator. Then the annual sales of each class are priced at this annual average variable cost to determine the responsibility of each class for the total variable production costs.

b) Fixed production costs are also traditionally allocated to classes of service as an average annual cost. Annual average fixed cost is calculated by dividing annual fixed costs by some measure of annual demand, including losses to the generator. Several variations of demands have been used, such as: coincident single peak; coincident summer peaks; coincident monthly peaks; average & excess; and average & peak. Whichever measure of demand is used, the corresponding annual demands of each class are priced at this annual average fixed cost to determine the responsibility of each class for the total fixed production costs.

Annual average cost pricing does not reflect how markets for electricity function. In hourly, or spot markets for electricity, generators in highly competitive markets will bid at marginal cost rather than at average variable cost with a fixed cost adder for profit. Based on this observation, it has been argued that pricing that is reflective of competitive markets for electricity would price each hour at the utility's marginal cost. However, there is a significant difference between a single utility's marginal cost and market price. There are two reasons

[1] Some studies also include variable operation and maintenance expense and rate of return on fuel inventory as variable costs.

for this difference. First, a given utility is only one of several participants in the market for electricity.[2] Thus, its individual marginal costs include only the bids of one of many agents and may not be representative of market prices. Second, marginal cost bids do not reflect what happens in the market when capacity is scarce. When capacity becomes scarce in the market, the market clearing price is not the utility's marginal cost bid price, rather it is determined by the demand's responsiveness to price; i.e., when there is not enough electricity to serve all loads, loads that are sensitive to price curtail usage until demand is equal to the scarce supply. During these hours of capacity scarcity is when the market determines an additional value for capacity above the difference between the utility's marginal and average cost. In the long run, this additional market value should be equal to the cost of adding peaking capacity.[3]

The time-of-use (TOU) methods for allocating electricity production costs described in what follows are designed to reflect the time varying nature of prices that are characteristic of competitive markets for electricity, but at the same time, take into account the difference between market prices and the embedded costs that are being allocated for a regulated utility.

2. TOU Energy Cost Allocation Factors

If a direct application of the utility's hourly marginal costs is used for pricing, then the difference between marginal cost and average variable cost reflects the return on investment in generation capacity to the utility. TOU energy costs are those costs that are reflective of the hourly spot market for electricity excluding the return on investment in production capacity. Thus, the TOU allocation of energy costs is based on the hourly average variable costs of the utility to serve its load. Average variable costs for each hour of a test year are used to price the hourly class loads, including losses to the generator. The hourly costs from this pricing are added over all hours of the test year for each class of service. Then the percent of these annual TOU energy cost totals are calculated for each class of service to obtain the annual TOU energy cost allocation factors.

This allocation of TOU energy costs to the hours is illustrated in Figure 1, where there are two blocks of hours of equal duration and two load levels. The marginal cost in the first block of hours is \$15/MWh and the marginal cost in the second block of hours is \$25/MWh.

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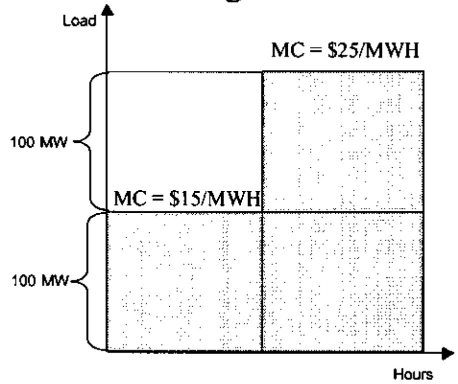
[2] If it is only one of a few participants, then the market will not be highly competitive.

[3] If the market values scarce capacity higher than the cost to build new capacity, then investors will build in order to capture that additional value. But building new capacity will reduce the scarcity and force the market price down. If the market values the capacity less than the cost to build, then investors will not add new capacity. As load grows and capacity is not added, this will result in a growth in capacity shortages to the market, and will increase the value that the market places on capacity.

Figure 1



Assuming that the marginal cost and average variable cost for the first block of hours are the same, then the average variable cost for the second block of hours is $20/MWh = the average of the $15/MWh with the $25/MWh. On the other hand, if the average variable cost in the first block of hours is below the marginal cost, say $5/MWh, then the average variable cost in the second block is only $15/MWh = the average of the $5/MWh with the $25/MWh.

3. TOU Capacity Cost Allocation Factors

Capacity costs are those costs that are reflective of the cost of adding new capacity to meet the load requirements of the utility. Additional capacity is needed whenever there is additional load. This need for additional capacity is also illustrated in Figure 1, where there are two blocks of production capacity. For the initial block of hours, there is only a need for 100 megawatts of production capacity. In the second block of hours, there is a need for an additional 100 megawatts of production capacity. The initial 100 megawatts of production capacity is required for both blocks of hours, and so its cost is allocated to both blocks. The additional 100 megawatts of production capacity is only needed in the second block of hours, and so its cost is only allocated to the second block of hours. If the value of the initial 100 megawatts of production capacity is the same as the additional 100 megawatts of production capacity, say $X, the allocation of capacity costs to the first block of hours would be $(1/2)X and the allocation to the second block of hours would be $(1/2)X + $X = $(3/2)X. Thus, the allocation of capacity costs to the second block of hours is three times the allocation to the first block of hours. With the megawatt-hours in the second block of hours being twice those in the first block of hours, the TOU capacity price in the second block of hours is higher than in the first block of hours.

With respect to the market, production capacity cost of each incremental block of load is not the same. There is a relationship between the marginal cost of production and the value of additional production capacity. For example, if the marginal cost of production in the two blocks of hours were the same, then the value of the production capacity to the two blocks of hours would also be the same. However, if the marginal cost of production in the second block of hours is greater than the marginal cost in the first block of hours, then the value of production capacity in the second block of hours will be equal to the value of production capacity in the first block of hours minus the difference in marginal costs between the two blocks of hours. In Figure 1, this difference is $10/MWh/hour. Assuming the capacity in the second block of hours is valued at $30/MW, then the value of the capacity in the first block of hours would be $20/MW. The capacity cost for the initial block of capacity would be $3,000 = $30/MW * 100 MW, and the capacity cost for the additional block of capacity would be $2,000 = $20/MW * 100MW. The TOU allocation of these costs would be $1,500 = $3,000 ÷ 2 to the first block of hours, and $3,500 = ($3,000 ÷ 2) + $2000 to the second hour. Instead of three times the capacity cost being allocated to the second period, this ratio has decreased to $2^{1}/_{3}$ = $3,500 ÷ $1,500. With the megawatt-hours in the second block being two times the megawatt-hours in the first block, the TOU capacity price in the second block of hours is still higher than in the first block of hours.

4. Application

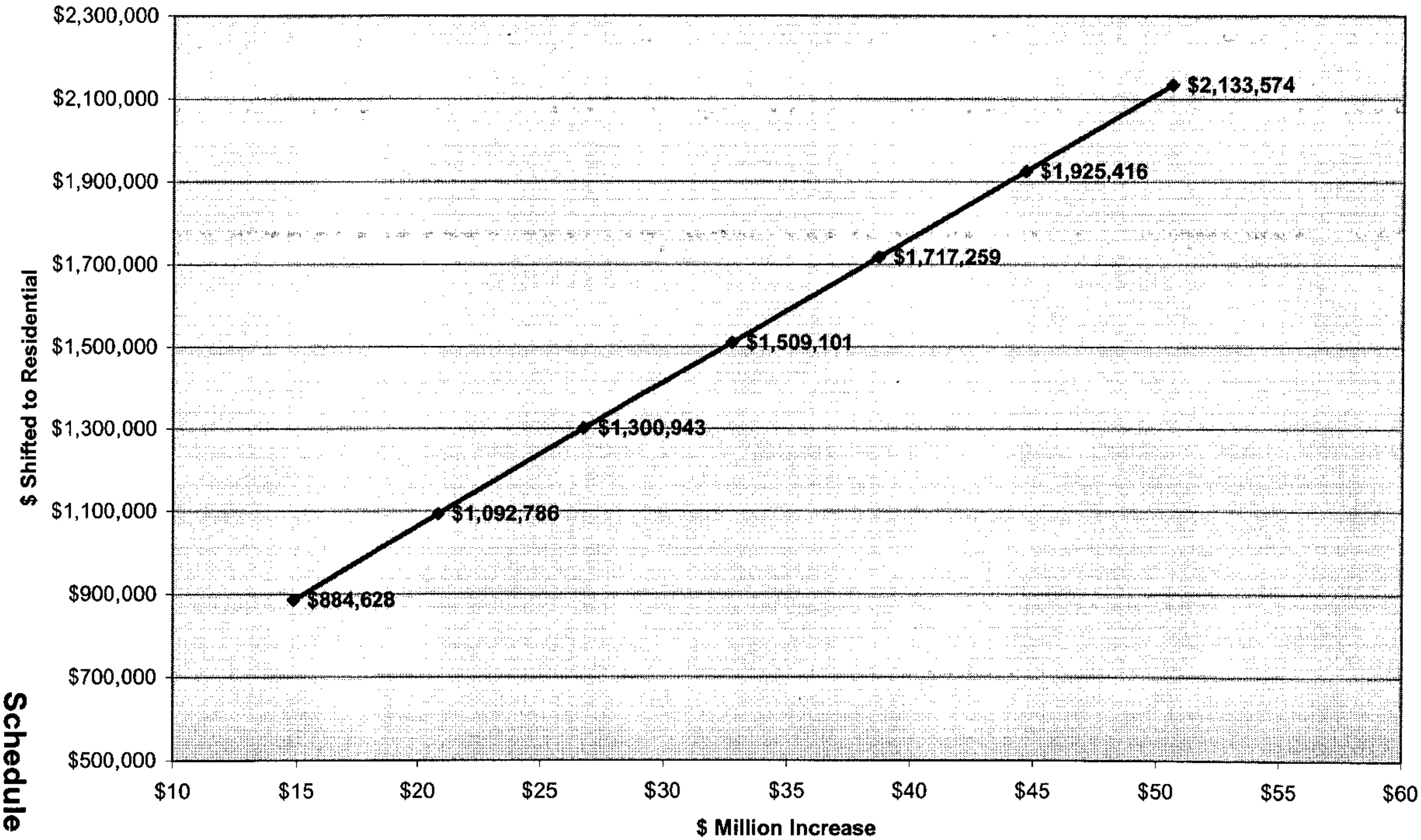
In application, there are 8,760 hours in a test year. Hourly costs are developed from production cost simulation models that are run with normalized hourly loads, normalized maintenance outage schedules and normalized purchased power. Each hour is assigned a variable average cost and marginal cost from the production cost model.[4] The average variable costs are used to price the hourly class loads and determine the TOU energy cost allocation factors.

To obtain the TOU hourly capacity costs, the capacity cost of a combustion turbine (peaking unit) is used for the peak hour, and the capacity cost for the next lower load hour is equal to the capacity cost at the peak hour minus the difference in the marginal costs between the peak hour and the next lowest load hour. This same procedure is repeated for each subsequent lower load hour. These capacity costs for each load are then allocated to hours when the load is at or above the specified load level, and then added across all load levels to obtain the allocation of capacity costs to a specific hour of the year. These hourly capacity costs are then allocated to each class of service in proportion to their contribution to the load at that hour, and added across all hours to obtain the contribution to TOU capacity costs for each class of service.

[4] The 8,760 marginal costs and matching loads are fit to a marginal cost curve that is monotonically increasing with the loads.

Revenue Shift to Residential from Equal % Increase

Baseline: TOU Energy + TOU Capacity Allocation



Schedule 5

ALLOCATION OF JOINT DISPATCH COST BETWEEN MISSOURI PUBLIC SERVICE AND ST. JOSEPH LIGHT AND POWER DIVISIONS OF UTILICORP UNITED

1. DEFINITIONS

1.1 NATIVE LOAD CUSTOMERS: MPS and SJLP retail customers and wholesale customers served either by contract or under a FERC tariff.

1.1.1 NATIVE LOAD: The electricity requirements of native load customers.

1.1.2 PEAK LOAD: The highest hourly electricity requirements of native load customers.

1.2 ELECTRICITY SUPPLY RESOURCES: The electricity output available to meet the load requirements of Missouri Public Service (MPS) and St. Joseph Light & Power (SJLP).

1.2.1 GENERATION RESOURCES: Electricity output available from generating units owned or leased by MPS or SJLP.

1.2.2 PURCHASE POWER RESOURCES: Contracts for electricity output from generation resource other than those owned or leased by MPS or SJLP.

1.2.3 DIVISION RESOURCES: Electricity supply resources that are directly assigned to either MPS or SJLP.

1.2.4 JOINT RESOURCES: Electricity supply resources available to meet the load requirements of MPS and SJLP, but not directly assigned to either division.

1.3 CAPACITY RESERVES: Megawatts of electricity available from electricity supply resources in excess of the forecasted peak demand of the native load customers of MPS and SJLP.

1.4 OFF-SYSTEM SALES: Short-term (spot) sales of electricity made to the wholesale electricity market from excess electricity supply resource capacity available after meeting the requirements of native load customers.

1.5 OFF-SYSTEM PURCHASES: Short-term (spot) purchases of electricity from wholesale electricity markets to replace higher cost electricity from electricity supply resources.

1.6 INCREMENTAL COST: From a stated level of electricity supply, the increase in costs associated with a specified megawatt increase to that electricity supply.

1.7 DECREMENTAL COST: From a stated level of electricity supply, the decrease in costs associated with a specified megawatt decrease to that electricity supply.

1.8 JOINT DISPATCH COSTS: Costs that vary with decisions made each day concerning which resources from either MPS or SJLP to use (dispatch) to meet electricity load requirements for MPS, SJLP and off-system sales. For purposes of these allocations, joint dispatch costs include only fuel costs net of revenues received from off-system sales.

2. Divisional Electricity Supply Resource Specification

2.1 Assignment of Existing Generation Resources

Generation resources designated as divisional resources to serve the native loads of Missouri Public Service (MPS) and St. Joseph Light & Power (SJLP) prior to August 16, 2001 will be assigned to the division in which they were designated resources prior to that date. This includes any changes in capacity that may occur at these generation resources.

2.2 Assignment of Existing Purchase Power Resources

Purchase power resources that were designated as divisional resources to serve the native load of MPS and SJLP prior to August 16, 2001 will be assigned to the division in which they were designated resources prior to that date. This includes any changes in capacity that may occur for these purchase power contracts over the term of the contract, but does not include the renewal of existing contracts.

2.3 Allocation of Joint Electric Supply Resources

Any additional electricity supply resources not assigned to divisions in 2.1 and 2.2 will be designated as joint resources. The capacity of these joint resources will be allocated between the two divisions in a manner that equalizes the capacity reserve margins between the two divisions based on the non-coincident peak demands forecasted for each division for the first summer period following the acquisition of the resource. This will determine each division's capacity share of joint resources. Each division's share of joint resource cost will be determined first by dividing total joint resource cost by total joint resource capacity to determine average cost per megawatt. Then each division's share of joint resource costs is calculated as its capacity share of the joint resources multiplied by the joint resource's average cost per megawatt. Once a portion of a joint resource is allocated to a division, it remains with that division into future periods.

3. Determination and Allocation of Profit Margin from Off-System Sales

3.1 Calculation of Hourly Cost for Off-System Sales

The megawatts of total off-system sales for an hour is the sum of all off-system sales for that hour. The cost assigned to off-system sales for each hour is equal to the decremental cost associated with the megawatts of off-system sales for that hour.

3.2 Calculation of Hourly Revenues for Off-System Sales

For each off-system sale, the hourly price and quantity will be recorded and the product of price and quantity added over all sales for that hour is the hourly revenues from off-system sales.

3.3 Calculation of Monthly Profit Margin for Off-System Sales

Each month, the hourly cost from 3.1 and hourly revenues from 3.2 will be added to obtain monthly off-system sales revenues and monthly off-system sales costs. The profit margin for off-system sales for the month is the difference between the monthly off-system sales revenues and monthly off-system sales costs.

3.4 ALLOCATION OF MONTHLY PROFIT MARGIN FROM OFF-SYSTEM SALES

The monthly profit margin from off-system sales will be allocated between the divisions in proportion to each division's annual share of capacity from assigned plus allocated electricity supply resources. Annual share of assigned and allocated capacity is the capacity ratings to meet the summer peak demand. These shares for a given summer will be applied for the months starting June 1 going into the summer period, through May 31 of the next year.

4. DIVISIONAL ALLOCATION OF COSTS FROM OFF-SYSTEM PURCHASES

4.1 CALCULATION OF HOURLY COSTS FOR OFF-SYSTEM PURCHASES

The product of price time megawatts added over all purchases for a given hour is the hourly cost for off-system purchases. Megawatts added over all purchases for a given hour is the hourly megawatts for off-system purchases. For each hour, the average hourly cost for off-system purchases is the hourly costs for off-system purchases divided by the hourly megawatts for off-system purchases.

4.2 ALLOCATION OF HOURLY ENERGY AND COSTS FOR OFF-SYSTEM PURCHASES

To determine the hourly purchase megawatt increment for each division, the hourly megawatts for off-system purchases is multiplied by each division's share of hourly native system load. The hourly incremental cost corresponding to each division's purchase megawatt increment is calculated from each division's assigned and allocated resources available for dispatch in that hour.

4.2.a If the hourly incremental cost for *both* divisions is either greater than, less than or equal to the average hourly cost for off-system purchases, then each division is allocated 1) megawatts of off-system purchases equal to its hourly purchase megawatt increment, and 2) costs equal to its allocated megawatts of off-system purchases times the average hourly cost for off-system purchases.

4.2.b If the hourly incremental costs of the two divisions are not equal, one division's hourly incremental cost is less than or equal to the average hourly cost for off-system purchases and the other division's hourly incremental cost is greater than or equal to the average hourly cost for off-system purchases, then both the hourly megawatts for off-system purchases and hourly costs for off-system purchases are allocated to the division with the higher hourly incremental cost.

5. DETERMINATION OF ENERGY TRANSFERS BETWEEN DIVISIONS

5.1 HOURLY CAPACITY FOR EACH DIVISION

The hourly megawatts from off-system purchases allocated to each division in 4.2 above is added to the megawatts of assigned and allocated resources for each division being used to meet load in the joint dispatch to determine each division's hourly capacity.

5.2 HOURLY ENERGY TRANSFERS

If hourly capacity is greater than its hourly load for one division, then the megawatt difference between capacity and load will be transferred to the other division.

6. Determination of Stand-Alone Costs for Each Division

6.1 Determination of Initial Share of Joint Dispatch Costs

For each month, the costs and megawatt hours of assigned and allocated resources for each division are determined. To each of these is subtracted a share of megawatts and costs allocated to off-system sales using the profit margin allocation factors for the month. To this is added the sum over the month of megawatts and costs from off-system purchases allocated to each division. This is the initial share of joint dispatch costs prior to taking into account energy transfers.

6.2 Costing the Energy Transfer

For purposes of calculating the stand-alone costs for each division the following pricing of the hourly energy transfer will be used.

- 6.1.a For the division making the energy transfer the cost of the hourly transfer is its decremental cost – recorded as a negative cost.
- 6.1.b For division receiving the energy transfer the cost of the hourly transfer is its incremental cost – recorded as a positive cost.

6.3 Calculating Stand-Alone Costs

For purposes of calculating the monthly stand-alone costs for each division, the megawatts and costs of the energy transfers will be summed over all hours in the month and will be added to the initial share of joint dispatch costs.

7. Divisional Allocation of Monthly Joint Dispatch Costs to Serve Native Load

7.1 Calculating Total Monthly Benefit from Joint Dispatch

Monthly stand-alone costs for each division as calculated in 6.3 are added to determine total stand-alone costs. The total monthly benefit from joint dispatch is equal to the difference between the monthly stand-alone cost and the monthly joint dispatch costs.

7.2 Allocation of Monthly Joint Dispatch Costs

Each division's monthly stand-alone costs are divided by total monthly stand-alone costs, and these shares of stand-alone costs are multiplied by monthly joint dispatch costs to determine each division's allocation of monthly joint dispatch costs.

7.3 Calculation of Divisional Monthly Benefit from Joint Dispatch Costs

The share of each division's allocation of monthly joint dispatch costs is subtracted from each division's monthly stand-alone costs to determine each division's monthly benefit from joint dispatch costs.

7.4 Calculation of Each Division's Monthly Net Dispatch Costs

Each division's allocation of monthly profit margin from off-system sales from 3.3 is added to the each division's allocation of monthly joint dispatch costs from 7.2 to determine each division's monthly net dispatch costs.