Exhibit No.:	______________
Issue(s):	Mains Allocator/ Rate Design
Witness/Type of Exhibit:	Hong Hu/Direct
Sponsoring Party:	Public Counsel
Case No.:	GR-2001-629

DIRECT TESTIMONY

OF

HONG HU

Submitted on Behalf of the Office of the Public Counsel

Laclede Gas Company
Case No. GR-2001-629

October 16, 2001

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of Laclede Gas Company's) Case No. GR-2001-629
Tariff to revise Natural Gas Rate Schedules)

AFFIDAVIT OF HONG HU

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Hong Hu, of lawful age and being first duly sworn, deposes and states:

1. My name is Hong Hu. I am a Public Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony consisting of pages 1 through 21 and Schedules DIR HH-1 and DIR HH-2 .

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Hu Hong

Hong Hu

Subscribed and sworn to me this 16th day of October, 2001.

Bonnie S. Howard, Notary Public

BONNIE S. HOWARD
MY COMMISSION EXPIRES
NOTARY SEAL
NOTARY PUBLIC
STATE OF MISSOURI

My commission expires May 3, 2005.

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DIRECT TESTIMONY

OF

HONG HU

LACLEDE GAS COMPANY

CASE NO. GR-2001-629

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Hong Hu, Public Utility Economist, Office of the Public Counsel, P. O. Box 7800, Jefferson City, Missouri 65102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I hold a Bachelor of Engineering degree in Management of Information Systems from Tsinghua University of Beijing, China and a Masters of Arts degree in Economics from Northeastern University. I have completed the comprehensive exams for a Ph.D. in Economics from the University of Missouri at Columbia. I have been employed as a regulatory economist with the Office of Public Counsel (OPC) since March 1997.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to present the OPC's development of allocation factors for transmission and distribution mains for use in the class cost of service study prepared by OPC witness James Busch. I will also discuss the details of OPC's rate design recommendation.

I. ALLOCATION OF MAINS COST

Q. WHY IS THE ALLOCATION OF MAINS COST AN IMPORTANT ASPECT OF CLASS COST OF SERVICE STUDIES?

A. In order to design customer rates for a utility company, class cost of service (CCOS) studies are commonly conducted in order to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs. In a CCOS study, mains cost allocation is very important because the cost of transmission and distribution mains accounts for a large part of the total system cost. Different methodology for allocating mains cost in a CCOS study will likely lead to different customer class revenue responsibility results. On the other hand, the allocation of mains cost has been a very controversial issue. Different parties to a case prefer different mains allocation methods and thus the parties' results vary widely from each other.

Q. WHY ARE THERE LARGE DISCREPENCIES IN THE ALLOCATION OF MAINS COST?

A. The existence of the large discrepancies in the allocation of mains cost is rooted in the characteristics of the main systems - Mains cost is a shared cost. The Company's investment in mains provides the Company with the means to deliver the gas to locations of all customer classes in response to customers' year-round demands for natural gas or have it available to back up other fuel sources. All customers benefit from the existence of mains on every day that they use gas. The total costs of mains in a utility are much less than the sum of stand-alone costs of mains would be if one system of mains were used by one customer or one customer class separately.

It cannot be disputed that since all customers benefit from the existence of the mains system, all customers should contribute to the recovery of the cost of this mains system. Economic theory states that if each customer or class of customers is responsible for at least the incremental cost that this customer brings to the system, and that if no customer or class of customers is responsible for more than the stand alone cost that would be needed to serve this customer individually, then there is no cross-subsidy and the allocation of cost can be acceptable. However, both the incremental cost and the stand-alone cost of each customer class are hard to measure or determine. To accurately pinpoint cost responsibility of each specific customer class is inherently impossible.

Q. PLEASE EXPLAIN THE CONTROVERSIES REGARDING DIFFERENT MAINS COST ALLOCATION METHODS.

A. There are two primary controversies arising from different mains cost allocation methods. The first controversy is in the classification step of a CCOS study. Some people believe that a portion of mains cost should be classified as customer-related and others do not. The second controversy is in the allocation step of a CCOS study. Different experts advocate different methods of allocating the capacity-related mains cost.

Q. PLEASE EXPLAIN THE FIRST CONTROVERSY IN MAINS COST ALLOCATION.

A. In a CCOS study, costs can be classified as customer-related, capacity or demand-related, and energy or commodity-related. It is commonly agreed that at least a portion of the distribution mains systems should be classified as demand-related since some portion is related to maximum system requirements which the system is designed to serve during short intervals and does not directly vary with the number of customers or their annual usage. However, some people argue that a portion of the costs associated with the distribution system may be classified as customer-related costs. One argument for inclusion of part of distribution mains in the customer cost classification is that there is a zero or minimum size main necessary to connect each customer to the system and thus afford the customer an opportunity to take service if he so desires. The counter argument to the inclusion of certain distribution costs as customer costs is that mains are installed soly to serve the demands of consumers and should be allocated entirely to that function.

Representatives of residential and other small customers have vigorously opposed the so-called “minimum size method”. The minimum size method classifies costs related with the minimum size mains as customer-related and allocate this cost according to weighted or unweighted customer number. Then the costs associated with distribution mains in excess of the minimum size plant are classified as demand-related and allocated to each customer class. The problem with this approach is that unavoidably, the minimum size facility has a certain load-carrying capacity. As a result of this method, small users would be allocated the cost of a minimum size distribution system that already satisfies much of their demand needs. In addition, they would be allocated another portion of the cost based on their demands. This method therefore results in a double allocation of cost to small users unless the demand capacity of the minimum system is subtracted from class demands prior to allocating the demand-related costs. It is likely that this method would result in some small customers receiving an allocated cost that is even greater than their stand-alone cost.

Other experts attempt to correct the minimum load double allocation problem by advocating another method, the "zero-intercept method" or the "minimum-intercept method". It assumes that a no-load distribution system can be identified and allocated based on customer numbers. The general technique of this method is to relate installed cost to current carrying capacity. A curve is created for various sizes of the equipment involved, using regression techniques, and this curve is extended to a zero (no load) intercept. It is argued that this no load portion of the distribution mains costs are incurred solely to reach the customer's premise. Then incremental costs are incurred to satisfy different levels of the customer's demands. The problem with this method is that it attempts to identify the cost of something that does not physically exist and cannot actually be measured. The reference of a point that is outside the range that is defined by available data is generally forbidden in statistics because unreliable results can often be obtained. We have seen cases where negative cost were generated for the "no load mains system". These results and the faulty theoretical premise of this method raise serious doubt against the zero intercept method.

Q. DOES OPC CHOOSE TO CLASSIFY ANY MAINS COST AS CUSTOMER-RELATED?

A. No. I do not believe that any of the mains cost that are shared among all customers should be classified as customer-related. Previously, based on the assumption that mains that have a diameter of 2" or smaller may not be used in serving customers that have relatively large demand, OPC had directly assigned a portion of distribution mains system that corresponds to those mains that have a diameter of 2" or smaller to the residential and commercial & industrial general service customer classes. After further discussion with the Company, I realized that such a direct assignment may not be fully justified. Gas can travel through any number of paths. If a customer is not connected to a 2" or smaller main, that does not mean that the gas he is getting has not flowed through a 2" or smaller pipe. The entire integrated distribution system is designed and constructed to serve the entire customer base. The specific path that gas actually travels through depends on many factors such as the customer's location, system pressure, time of day, etc. Therefore, we cannot specify a certain portion of the system that is dedicated to a certain customer or a certain customer class without some detailed engineering analysis to support this assumption. However, I do believe that it is possible that larger customers such as large volume and transportation customers may receive proportionally less benefit through those smaller size distribution mains (e.g. mains 2" or less in diameter). Therefore, I have chosen to continue directly assigning a portion of the distribution mains that corresponds to mains of size 2" or less (approximately 27%) to the residential and commercial & industrial general service customers. The rest of the mains cost are allocated to all customer classes as a shared capacity-related cost. I would note, though, that the distribution mains allocators that resulted from this treatment may have over-allocated cost to the residential and commercial & industrial general service customers to a certain degree.

Q. PLEASE EXPLAIN THE SECOND CONTROVERSY IN MAINS COST ALLOCATION.

A. There are a wide variety of alternative methods for determining and allocating capacity-related costs such as mains cost that produce drastically different cost assignments to the various customer classes. Each method has received support from some rate experts and no method is universally accepted. The electric industry has produced more alternatives than the gas industry. Different methods that I've come across in my past experiences in gas and electric cases include the following: the peak demand responsibility methods, the average and peak demand allocation method, the average and excess demand method, and the time differentiated allocation method.

Q. PLEASE DESCRIBE THE PEAK DEMAND RESPONSIBILITY METHODS.

A: A commonly used group of methods is called the peak demand responsibility method. This group of methods allocates the mains costs on coincident or non-coincident peak demand. Among this group, the single system coincident peak (1CP) demand allocation method uses the single annual system peak to measure customer cost responsibility. Adovates of this method assume that since a major factor that drives the design of the system is the highest peak demand, the incremental cost of delivering gas on any day other than the peak day is zero. Therefore, this method allocates the total cost to the peak day and allocates zero cost to the other days. This method fails to reflect the fact that the utility system is built to satisfy the customers' daily demands for gas, not only the demands on the peak day, and allocates the entire cost of the joint production according to usages on a single day. Under this method, interruptible customers would generally receive no allocation of demand-related costs for their non-firm demand of gas, since they are assumed to be off the system during the peak period. In other words, if this method is adopted, interruptible customers would receive a "free ride" to use the distribution main system without paying its costs.

The non-coincident peak demand (NCP) allocation method attempts to correct the problem with the 1CP method by allocating the cost of the facilities in accordance with each customer class's contribution to the sum of the maximum demands that all customer classes' impose on the facilities. This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method will allocate some cost to interruptible customers since their non-coincident demand would not be zero. However, this method still suffers from the flaw that it does not recognize that the system is built for the joint production to satisfy the everyday gas usage needs for all customers. It essentially allocates all costs to the one day of usage when the class non-coincident peak happens for the class and allocates nothing to the class's non-peak usage in the rest of the year.

Q. PLEASE DESCRIBE THE AVERAGE AND PEAK DEMAND METHOD AND THE AVERAGE AND EXCESS METHOD.

A: The average and peak demand (A&P) method attempts to account for the annual energy supply needs of the company in addition to the capacity needs. Total mains cost are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and these capacity costs are apportioned to the various customer classes on an annual energy usage basis. The rest of the costs are considered to have been incurred to meet the coincident peak demands of the various classes of service. For example, if the load factor is 55%, then 45% (1-55%) of the total mains cost is considered to have been incurred because of the peak demand and is allocated to peak users.

The "average and excess" (A&E) allocation method appears to be similar to the A&P method because both methods divide the total cost into two parts based on the system load factor and both methods allocate the average usage portion based on average annual usage. However, this method differs drastically from the A&P method in its allocation of the demand portion. By allocating demand-related cost based on excess demand instead of total demand, this method gives a disproportionate advantage to customers who use the system in a continuous manner and have little excess demand, and penalizes customers with low load factors and high excess demand.

Q. PLEASE GIVE AN EXAMPLE TO ILLUSTRATE HOW DIFFERENT RESULTS ARE OBTAINED FROM DIFFERENT ALLOCATION METHODS.

A. The following example illustrates the results of three allocation methods for two customers. These two customers have the same annual gas usage. However, they have different load factors. In other words, one customer uses the system in a more continuous manner and the other customer has a more variable usage pattern and would cost the system more to satisfy its maximum demand. An appropriate allocation method would be expected to allocate more cost to the customer with the lower load factor.

Table 1. Demand and usage information for two customers with different load factors

Customer	Load Factor	Average Demand (Annual Usage)		Coincident Peak Demand		Noncoincident Peak Demand		Excess Demand	
Customer 1	0.8	100	(50%)	120	(37.5%)	125	(38.5%)	25	(20%)
Customer 2	0.5	100	(50%)	200	(62.5%)	200	(61.5%)	100	(80%)
Total	0.625	200	(100%)	320	(100%)	325	(100%)	125	(100%)

Table 2. A comparison of different allocation methods

Customer	Peak responsibility allocation method (1CP)	Peak responsibility allocation method (1NCP)	A&P Allocation method	A&E allocation method
Customer 1	37.5%	38.5%	50%*0.625+37.5%*0.375 = 45%	50*0.625+20%*0.375 = 38.75%
Customer 2	62.5%	61.5%	50%*0.625+62.5%*0.375 = 55%	50%*0.625+80%*0.375= 61.25%
Total	100%	100%	100%	100%

The above example shows that different cost allocations would be generated by different allocation methods based on the same demand and usage data. Here all methods allocated more costs to customer 2 who has a lower load factor. However, the 1CP and 1NCP methods only rely on the peak demand and do not give any consideration to the annual energy usage. The result for A&P method reflects consideration of both factors. In contrast, although the A&E method appears to allocate a portion of the total cost based on annual usage, it also allocates a large portion of the excess cost to the customer with a low load factor. Therefore, although the A&E method gives the appearance that it has considered the effect of the annual energy usage, its generally generates an end result that is very similar to a peak responsibility method.

Q. PLEASE EXPLAIN THE TIME DIFFERENTIATED ALLOCATION METHOD.

A. It is argued that traditional demand allocation methods do not consider differences in use over the course of a year and a time differentiated allocation method better reflects the fact that capacity-related costs are determined by loads throughout the year. It is argued that this kind of allocation methodology is equitable because every customer, large or small, residential or industrial, receives exactly the same cost allocation as every other customer taking service in the same time. For example, if a portion of the system is running year-round, then this method would allocate the corresponding cost to all hours (8760 hours) of the year. If a further portion of the system is used all the time but one hour, then the method would allocate the cost that corresponds to this portion of the facitlities to the 8759 hours. This goes on and on until the last unit of the system that is only utilized in 1 hour and its cost would be allocate to this hour only. This way it is only the difference in the timing of each class's usage that results in differences in the costs allocated to the classes for the entire year.

In past electric and gas cases, the Commission Staff and OPC have allocated capacity-related costs based on each class's contribution to the sum of hourly class loads at each hour (time-of-use allocation method), or based on each class's contribution to the monthly peak demand in each month (the relative system utilization method or "value of service" method).

Q. WHAT METHOD HAS OPC USED TO ALLOCATE MAINS COST IN THIS CASE?

A. Since OPC does not have resources to run a production model and thus allocate costs to each hour when the mains system is runing, I have chosen to use the modefied relative system utilization method (RSUM) for the allocation of mains system cost. Applying this method, I have used monthly non-coincident peak day demand as a proxy of relative system utilization in different time periods to developing an allocation of cost to different customer classes.

Q. PLEASE EXPLAIN THE RELATIVE SYSTEM UTILIZATION METHOD.

A. The original RSUM method was developed by Charles Laderoute in a paper that he presented at the 1988 NRRI Biennial Regulatory Information Conference and modified by former OPC economist Philip Thompson in a paper he presented at the 1992 NRRI Biennial Regulatory Information Conference. The basic idea of this method is to identify the portion of capacity that corresponds to each month's demand, and allocate the cost that corresponds to that capacity to customers who use gas in the month that this portion of the system is used. For example, if 50% of capacity is used in 12 months of the year and 55% of capacity is used in 11 months, the extra 5% of capacity is not utilized in one month, say, July. This method allocates the cost corresponding to 50% of capacity to every month, and customers who use gas in every month would receive a share of the costs that is corresponding to the 50% capacity. Further, customers who use gas in every month but July will also receive a share of the cost that is corresponding to the additional 5% capacity.

Q. PLEASE EXPLAIN THE MODIFICATIONS YOU HAVE MADE TO THE RSUM METHOD AND WHY SUCH MODIFICAITONS ARE NECESSARY.

A. An important characteristics of mains cost is the presence of economies of scale. According to various flow formulas, a 4" pipe has a flow capacity of about 6 times that of a 2" pipe. On the other hand, the per foot cost to install the 4" pipe may be less than 2 times of the cost to install the 2" pipe. This means that the cost of the incremental capacity needed to serve the peak is less than the average cost of capacity. For reference, I have attached a table that OPC former engineer, Barry Hall, presented in a previous gas rate case. This table shows the comparison of available flow capacity for some common sizes of mains based on the flow capacity of a 2" main being equal to one.

Table 1. Relative Flow Capacity vs. Main Diameter[1]

Main Diameter	Relative Flow Capacity (2" Dia. Main = 1.0)
2"	1.0
4"	6.3
6"	18.6
8"	40.0
12"	117.5
24"	742.4

In order to capture this nonlinear relationship between the capacity (demand) and cost, I have employed an economies of scale factor, ***r***. This factor converts the share of peak day demand to the share of total capacity costs by raising the capacity percentages to the ***r***th power. The factor ***r*** is a measurement of the degree of the economies of scale. There will be no economies of scale if ***r*** equals 1. Previously Mr. Hall had studied several gas and electric companies and found an appropriate quantification for the factor ***r*** to be 0.3. Utilizing this factor, if the capacity ratio of a 4" pipe and a 2" pipe is 6:1, the corresponding cost ratio is determined to be $(6^{0.3}/1^{0.3}) = 1.71$.

[1] Barry F. Hall, Direct Testimony, Case No. GR-97-393, page 7.

Q. PLEASE PROVIDE A STEP BY STEP DESCRIPTION OF THE MODIFIED RELATIVE SYSTEM UTILIZATION METHOD.

A. Please refer to Schedule DIR HH-1.1. The second column of this schedule contains the sum of weather-normalized non-coincident monthly peak day demands for all customer classes sorted in descending order. This information was provided by Staff witness Dan Beck.

In the next column (Months % of Annual Peak) the peak day demands are converted to percentages of the maximum monthly peak day demand. For instance, the month having the second highest peak day demand has a peak that is 92.67% of the maximum peak day demand. Another way of stating this is that there is an 7.33% increment of demand separating the two months.

In the fourth column, the percentages of monthly peak day demand are converted to percentages of total capacity costs by raising the capacity percentages to the *r*th power. Considering the third and the fourth columns it is easy to state what is indicated by the mathematical relationship here. The first 11.23% of capacity requires an expenditure of more than 51% of the costs of the system, i.e. there are substantial fixed costs involved. Likewise, 50.83% or approximately half of the capacity requires over 81% of the total costs to supply. Conversely, adding roughly the <u>last</u> 50% of the capacity accounts for less than 20% of the costs.

The fifth column simply calculates successive differences in percentages of costs from the fourth column. The top figure is the difference in percentage costs incurred to supply the additional capacity in moving from the second highest monthly peak to the maximum monthly peak day demand. The second figure in this column is the same difference, only moving from the third highest monthly peak to the second highest monthly peak.

The adjacent column depicts the number of months over which that cost increment should be spread. The first (highest or top increment) cost increment, occurring only on the peak day of one month is only spread to that month. The next increment of cost/capacity is utilized for two months. The last or base increment is utilized in all the months. Each cost increment is divided by the number of months in which the corresponding capacity increment is utilized.

In the last column partial sums are formed for the cost increments utilized in each month. For instance, the peak month sums all the increments of costs in the previous column, since all increments of capacity are used in that month. The next partial sum for the next lowest month omits the top cost increment in its sum and so on. The result is the percentage of capacity costs attributable to each month.

Refer to Schedule DIR HH–1.2. The top block of numbers is the class peak day demands by month that Mr. Beck provided. The next block of numbers simply repeated the same information only rearranged by sorting according to the peak day demands. In the block below, class peaks have been converted to percentages of the sum of peak day demands for all the classes each month.

Summing the product of the class share of monthly peaks on Schedule DIR HH–1.2 and the portion of total capacity costs in each month in the last column on Schedule DIR HH–1.1 gives the RSUM allocators at the bottom of Schedule DIR HH–1.2. These are RSUM allocators that are applicable to the Company's transmission mains system. Schedule DIR HH–1.3 shows the development of the distribution mains allocators that is based on the RSUM allocators and a direct assignment of 27% of cost to the residential class and the commercial & industrial gerneral service class.

II. CLASS COST OF SERVICE STUDY RESULTS AND RATE DESIGN ANALYSIS

Q. PLEASE DESCRIBE THE RESULTS OF OPC'S CCOS STUDY.

A. OPC's CCOS study was performed by James Busch. The result of OPC's CCOS study indicates that the margin rate level for the Residential class and the Firm Transportation class are currently producing returns that exceed the total company return. Conversely, the Commercial and Industrial GS, Large Volume, Interruptible, and Basic Transportation classes are currently producing a return below the level of the total company return. The results that the study shows for LP and UMGL classes should be interpreted with caution since this class is very small and certain cost information was not available in the study. I have omitted these two classes in any further rate design analysis. The class rate of return information is summarized below in Table 2.

Table 2 – COS Indicated Customer Class Returns

	Residential	Com. & Ind.	Large Volume	Inter-ruptible	Firm	Basic	LP	UMGL
Returns	9.81%	3.74%	2.33%	5.69%	11.97%	6.20%	13.85%	79.53%

In Table 3, I have also summarized the class revenue shift indicated by OPC's CCOS study in order to equalize class rates of return if the Company's total revenue remains at the current level.

Table 3 – CCOS Indicated Revenue Neutral Class Revenue Shifts (thousand dollars)

	Residential	Com. & Ind.	Large Volume	Inter-ruptible	Firm	Basic
Class Shifts	(6,372)	5,657	616	45	(409)	463
% Change	-3.67%	15.02%	22.82%	9.44%	-9.79%	7.23%

Q. WHAT IS THE RELATIVE IMPORTANCE OF CLASS COS STUDY RESULTS IN RATE DESIGN?

A. A number of factors must be considered when determining the just and reasonable rate for a service. The factors include cost of service, the value of service, affordability, rate impact, and rate continuity. A CCOS study provides the Commission with a general guide as to the cost aspect of the just and reasonable rates. The manner in which the cost factor and all the other factors are balanced by the Commission in setting the rates can only be determined on a case-by-case basis.

Q. WHAT RATE DESIGN PRINCIPLE IS OPC PROPOSING BASED ON THE REVENUE SHIFTS NEEDED TO EQUALIZE CLASS RATES OF RETURN INDICATED IN TABLE 2 FOR THIS CASE?

A. OPC recommends that the Commission adopt a rate design that balances movement towards cost of service with rate impact and affordability considerations. To reach this balance, OPC believes that the Commission should impose, at a maximum, revenue shifts equal to one half of the revenue neutral shifts indicated by OPC's CCOS study. In addition, if the Commission determines that an increase in the total company revenue requirement is necessary, then no customer class should receive a net decrease as the combined result of the revenue neutral shift that is applied to that class and the share of the total revenue increase that is applied to that class.

Q. YOU JUST NOTED THAT RATE IMPACT AND EQUITY CONSIDERATIONS SHOULD BE TAKEN INTO ACCOUNT IN DETERMINING ANY APPROPRIATE INTERCLASS REVENUE SHIFTS THAT WOULD BE PART OF THE RATE DESIGN RESULTING FROM THIS CASE. PLEASE EXPLAIN HOW THIS CONSIDERATION SHOULD BE APPLIED.

A. As I pointed out earlier in this testimony, OPC's CCOS study in this docket demonstrates that there are some significant interclass subsides incorporated in the Company's rate design. In other words, the class revenues that are being collected from each of the classes as a result of the currently tariffed margin rates are causing certain classes to make payments for service that greatly exceed the cost of the service that is being provided to them. For the most part, OPC's results are not showing anything significantly different than OPC's CCOS study showed in the most recent Laclede rate case, GR-99-315. While in the previous case very modest changes in the Company's rates were accomplished through negotiated settlement, those changes were less than the changes needed to bring the rates closer to costs.

OPC has recommended that the Commission adopt a rate design that only goes, at most, half-way towards our study results, due to rate impact, equity, and affordability considerations. The Commission could reasonably determine that even going half-way towards OPC's study results is too big of a jump to make in one step due to these same considerations.

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN SCHEDULE DIR HH-2 AND EXPLAIN HOW IT WAS CALCULATED.

A. Schedule DIR HH-2 shows how OPC's rate design principle can be applied assuming the Commission approved total company revenue increase is at $1 million, $12 million and $40 million. The same series of calculations can be repeated for any revenue requirement increase or decrease that is determined by the Commission. The schedule illustrates the combined impact of spreading three potential revenue requirement increase amounts to customer classes and the revenue neutral class revenue shifts recommended by OPC.

For example, line 15 of this Schedule shows how the $1 million revenue requirement increase has been spread to the various customer classes. Then line 20 shows the combined impact of the $1 million revenue increase and revenue neutral shift for each class was derived by adding each classes' share of the $1 million revenue requirement increase to the revenue neutral shifts that OPC has recommended for each class. For example, in line 15, we see that $758,000 is allocated to the residential class as a result of spreading a revenue requirement increase of $1 million. This $758,000 amount is then added to the negative $3,186,000 revenue neutral shift amount for the residential class that appears in line 10. The sum of these two amounts, negative $2,429,000, appears in line 20 under the residential column and represents OPC's recommendation for the combined impact of revenue neutral shifts and share of overall revenue requirement increase that should be reflected in rates resulting from this case if the overall revenue requirement is increased by $1 million.

Q. PLEASE EXPLAIN HOW THE ADJUSTED COMBINED IMPACT AMOUNTS THAT APPEAR IN LINES 24 THROUGH 27 OF SCHEDULE DIR HH-2 WERE CALCULATED.

A. Based on rate impact and equity considerations, OPC believes that no customer class should receive a net class rate revenue increase when there is an overall revenue requirement reduction and no customer class should receive a net class revenue decrease when there is an overall revenue requirement increase. The combined impact of revenue increase and OPC's revenue neutral shift numbers are thus adjusted further to reflect this consideration. For example, for the case of a $1 million increase, line 15 of Schedule DIR HH-2 shows that the spread of the overall revenue increase to the residential class and the firm transportation class are too small to offset their respective revenue neutral shifts. This causes these two classes to end up with a net decrease (shown in line 20). In fact, if the final commission approved total company revenue increase amount is less than 12 million, moving half-way to OPC's CCOS study result would mean that the residential class and/or the firm transportation class may receive a net decrease. In this case the following steps should be followed to get our recommended result: (1) keeping the current residential and/or firm class rate revenue requirement unchanged; (2) giving each of the other classes the share of the increase shown in lines 20; and (3) reducing the increase in other class revenue requirements by an amount equals to the sum of the residential and/or firm transportation net decreases that were eliminated. Line 25 and line 30 respectively show the final OPC recommended class revenue shifts, and the class revenue percentage results from this series of allocations of the total company revenue requirement to each class at the $1 million level.

Q. PLEASE SUMMARIZE OPC'S RATE DESIGN RECOMMENDATION FOR THE CLASS REVENUE REQUIREMENTS THAT SHOULD RESULT FROM ANY INCREASE OR REDUCTION IN OVERALL REVENUE REQUIREMENT THAT THE COMMISSION DETERMINES TO BE REASONABLE IN THIS CASE.

A. In this testimony, OPC has proposed and illustrated the application of a method for increasing **class** revenue requirements to go along with any increase in the **overall** revenue requirement. This method could be utilized to calculate class revenue requirements for any level of overall revenue requirement increase or reduction that is ultimately decided in this case. Schedule DIR HH-2 shows the result of applying OPC's recommended method for determining class revenue requirements to potential revenue requirement increase levels of $1 million, $12 million or $40 million. OPC could supply similar calculations to the Commission for any other amounts of change in the overall revenue requirement if requested to do so.

Q. DID YOU PERFORM ANY ANALYSIS REGARDING LACLEDE'S RESIDENTIAL CUSTOMER CHARGE?

A. Yes, OPC's CCOS study showed that the customer-related cost, which is one of the factors considered in the determination of a customer charge level, is $10.83. The customer-related cost calculation was based on the assumption that Laclede's costs are accurately reflected in the accounting schedules contained in the Staff's direct testimony filing. The costs that are included in the customer charge calculation are the costs that are related to services, meters, regulators, and customer accounts expenses. The costs associated with services, meters, and regulators include the return on rate base for the relevant plant accounts, distribution operation and maintenance expenses associated with services, meters, and regulators, plus the depreciation expense associated with services, meters, and regulators.

Q. WHAT IS OPC'S PROPOSAL FOR THE CUSTOMER CHARGE FOR RESIDENTIAL CUSTOMERS?

A. OPC recommends decreasing the residential customer charge from its current level of $12.00 to $11.00. Reducing Laclede's residential customer charge to this level would put this charge more in line with the residential customer charges of other Missouri LDCs. Laclede's residential customer charge is currently the highest for any Missouri LDC. The rest of residential class rate revenue requirement should be recovered from the commodity charge. We are not making any recommendations at this time regarding rate components for the other customer classes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Calculation of RSUM Allocators

Economy of Scale Factor[1]
r = **0.3**

Month	Montly Sums of Class Peaks	Monthly % of Annual Peak	% of Cost to Satisfy Capacity	% Cost Increment in Month Over Previous Month	No. Months with Increment	Increment /Months Occuring	Sum of Cost Increments Occuring Each Month
Jan	9,192,862	100.00%	100.00%	2.26%	1	2.26%	14.86%
Feb	8,519,212	92.67%	97.74%	1.44%	2	0.72%	12.60%
Dec	8,106,832	88.19%	96.30%	6.93%	3	2.31%	11.88%
Mar	6,319,791	68.75%	89.37%	0.65%	4	0.16%	9.57%
Nov	6,167,671	67.09%	88.72%	7.09%	5	1.42%	9.41%
Apr	4,672,948	50.83%	81.63%	2.58%	6	0.43%	7.99%
Oct	4,199,156	45.68%	79.05%	8.44%	7	1.21%	7.56%
May	2,882,297	31.35%	70.61%	2.12%	8	0.27%	6.35%
Sep	2,603,419	28.32%	68.49%	10.36%	9	1.15%	6.09%
Jun	1,507,204	16.40%	58.13%	5.09%	10	0.51%	4.94%
Aug	1,110,544	12.08%	53.04%	1.14%	11	0.10%	4.43%
Jul	1,032,683	11.23%	51.90%	51.90%	12	4.32%	4.32%

Notes:
1 Each months percentage of annual peak is raised to the *rth* power to convert succesive monthly increments of capacity to increments of costs.

Calculation of RSUM Allocators (Cont.)

	Residential (therms/day)	General C&I (therms/day)	Large Volume (therms/day)	Interruptible (therms/day)	Firm Trans (therms/day)	Basic Trans (therms/day)	System Total
Jan	5,626,691	2,290,031	177,098	31,086	349,777	718,178	9,192,862
Feb	5,203,253	2,110,950	165,365	28,942	332,147	678,555	8,519,212
Mar	3,814,971	1,527,678	127,480	23,814	275,224	550,624	6,319,791
Apr	2,767,793	1,093,211	99,887	20,846	233,764	457,446	4,672,948
May	1,627,636	621,138	70,010	18,087	188,872	356,554	2,882,297
Jun	746,937	259,162	47,408	18,557	154,912	280,230	1,507,204
Jul	441,525	137,663	40,288	12,808	144,214	256,186	1,032,683
Aug	490,682	158,268	41,618	13,082	146,213	260,680	1,110,544
Sep	1,441,195	551,337	66,439	16,447	183,507	344,495	2,603,419
Oct	2,460,091	971,648	92,812	17,920	223,133	433,553	4,199,156
Nov	3,712,173	1,489,875	125,506	23,903	272,257	543,957	6,167,671
Dec	4,942,774	2,001,972	158,311	27,489	321,549	654,737	8,106,832

	Residential (therms/day)	General C&I (therms/day)	Large Volume (therms/day)	Interruptible (therms/day)	Firm Trans (therms/day)	Basic Trans (therms/day)	System Total
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Jun	746,937	259,162	47,408	18,557	154,912	280,230	1,507,204
Aug	490,682	158,268	41,618	13,082	146,213	260,680	1,110,544
Jul	441,525	137,663	40,288	12,808	144,214	256,186	1,032,683

Percentage of System Total for Each Month

Jan	61.21%	24.91%	1.93%	0.34%	3.80%	7.81%	100.00%
Feb	61.08%	24.78%	1.94%	0.34%	3.90%	7.96%	100.00%
Dec	60.97%	24.69%	1.95%	0.34%	3.97%	8.08%	100.00%
Mar	60.37%	24.17%	2.02%	0.38%	4.35%	8.71%	100.00%
Nov	60.19%	24.16%	2.03%	0.39%	4.41%	8.82%	100.00%
Apr	59.23%	23.39%	2.14%	0.45%	5.00%	9.79%	100.00%
Oct	58.59%	23.14%	2.21%	0.43%	5.31%	10.32%	100.00%
May	56.47%	21.55%	2.43%	0.63%	6.55%	12.37%	100.00%
Sep	55.36%	21.18%	2.55%	0.63%	7.05%	13.23%	100.00%
Jun	49.56%	17.19%	3.15%	1.23%	10.28%	18.59%	100.00%
Aug	44.18%	14.25%	3.75%	1.18%	13.17%	23.47%	100.00%
Jul	42.76%	13.33%	3.90%	1.24%	13.96%	24.81%	100.00%

RSUM	Residential	General C&I	Large Volume	Interruptible	Firm Trans	Basic Trans	System
Allocators	**57.85%**	**22.68%**	**2.28%**	**0.52%**	**5.70%**	**10.97%**	**100.00%**

COST ALLOCATION OF TRANSMISSION MAINS AND DISTRIBUTION MAINS

Main Diameter	Trended Costs		
1	$1,132,399	*Lower Usage Customers*	27.35%
2	$292,051,465		
3	$12,658,477		
4	$149,670,636		
5	$677,506		
6	$183,460,977		
8	$111,203,417		
10	$20,141,949	*Common System*	72.65%
12	$79,288,752		
13	$1,074,615		
14	$12,080		
16	$60,742,330		
18	$639,098		
20	$53,295,276		
22	$11,077,286		
24	$64,293,784		
26	$8,235,984		
30	$22,213,196		
	$1,071,869,226		

		Residential	General C&I	Large Volume	Interruptible	Firm Trans	Basic Trans
RSUM Allocators (Transmission Mains)		**57.85 %**	**22.68 %**	**2.28 %**	**0.52 %**	**5.70 %**	**10.97 %**
"Direct Assign"	27.35%	19.65%	7.70%				
Common System	72.65%	42.02%	16.47%	1.66%	0.38%	4.14%	7.97%
Sum	100.00%	61.67%	24.18%	1.66%	0.38%	4.14%	7.97%
Composite Allocator (Distribution Mains)		**61.67 %**	**24.18 %**	**1.66 %**	**0.38 %**	**4.14 %**	**7.97 %**

LACLEDE GAS COMPANY
Rate Design Methodology

Rate Design Analysis (000)	TOTAL	GS RESIDENTIAL	GS COM. & INDUSTRIAL	LARGE VOLUME	INTER-RUPTIBLE	FIRM	BASIC
Current Revenue	225,272	173,857	37,654	2,700	481	4,176	6,403
OPC CCOS %	99.98%	74.33%	19.22%	1.47%	0.23%	1.67%	3.05%
	100.00%	74.35%	19.23%	1.47%	0.23%	1.67%	3.05%
1 Revenue Neutral Shifts (RNS) to Equalize Class							
2 Rates of Return (ROR)	(0)	(6,372)	5,657	616	45	(409)	463
3							
4 Percentage Revenue Change to Equalize Class ROR	0.00%	-3.67%	15.02%	22.82%	9.44%	-9.79%	7.23%
5							
6 Current Class Revenue Percentages	100.00%	77.18%	16.72%	1.20%	0.21%	1.85%	2.84%
7							
8 COS Indicated Class Revenue Percentages	100.00%	74.35%	19.23%	1.47%	0.23%	1.67%	3.05%
9							
10 **OPC's Recommended Revenue Neutral Shifts (RNS)**	$ (0)	$ (3,186)	$ 2,828	$ 308	$ 23	$ (205)	$ 232
11							
12 OPC's Recommended Revenue Percentages	0.00%	75.76%	17.97%	1.34%	0.22%	1.76%	2.94%
13							
14 **Spread of Proposed Revenue Requirement Increases**							
15 $1 Million Revenue Requirement Increase	1,000	758	180	13	2	18	29
16 $12 Million Revenue Requirement Increase	12,000	9,091	2,156	160	27	212	353
17 $40 Million Revenue Requirement Increase	40,000	30,305	7,188	534	89	705	1,178
18							
19 **Combined Impact of Revenue Increase and OPC's RNS**							
20 Combined Impact $1 Increase and OPC Shifts	1,000	(2,429)	3,008	322	25	(187)	261
21 Combined Impact $12 Million Increase and OPC Shifts	12,000	5,905	4,985	468	50	7	585
22 Combined Impact $40 Million Increase and OPC Shifts	40,000	27,119	10,017	842	112	501	1,410
23							
24 **Adjusted Impact of Revenue Increases and OPC's RNS**							
25 Combined Impact $1 Increase and OPC Shifts	1,000	-	832	89	7	-	72
26 Combined Impact $12 Million Increase and OPC Shifts	12,000	5,905	4,985	468	50	7	585
27 Combined Impact $40 Million Increase and OPC Shifts	40,000	27,119	10,017	842	112	501	1,410
28							
29 **ADJUSTED REVENUE PERCENTAGE**							
30 Combined Impact $1 Increase and OPC Shifts	100.00%	76.84%	17.01%	1.23%	0.22%	1.85%	2.86%
31 Combined Impact $12 Million Increase and OPC Shifts	100.00%	75.76%	17.97%	1.34%	0.22%	1.76%	2.94%
32 Combined Impact $40 Million Increase and OPC Shifts	100.00%	75.76%	17.97%	1.34%	0.22%	1.76%	2.94%