Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Issue:	Cost of Service
Sponsoring Party:	Praxair, Inc.
Case No.	ER-2001-299

Before the Public Service Commission of the State of Missouri

In the Matter of The Empire District Electric Company's tariff sheets designed to implement a general rate increase for retail electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2001-299

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Missouri Public Service Commission

Rebuttal Testimony of

Maurice Brubaker

On behalf of

Praxair, Inc.

Project 7513
May 3, 2001

BRUBAKER & ASSOCIATES, INC.

ST. LOUIS, MO 63141-2000

Before the Public Service Commission
of the State of Missouri

In the Matter of The Empire District Electric Company's tariff sheets designed to implement a general rate increase for retail electric service provided to customers in the Missouri service area of the Company)	Case No. ER-2001-299

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Praxair, Inc. in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2001-299.

3. I hereby swear and affirm that the rebuttal testimony and schedules are true and correct and that they show the matters and things they purport to show.

Maurice Brubaker

Subscribed and sworn to before this 2nd day of May 2001.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2004

Carol Schulz
Notary Public

My Commission Expires February 26, 2004.

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In the Matter of The Empire District Electric Company's tariff sheets designed to implement a general rate increase for retail electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2001-299

Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q ARE YOU THE SAME MAURICE BRUBAKER WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A The purpose of my rebuttal testimony is to respond to the positions taken in the direct testimony of other parties on cost of service issues with which I disagree. In particular, I address the cost of service studies sponsored by the Staff of the Missouri Public Service Commission (Staff) and by the Office of Public Counsel (Public Counsel or OPC), which produced results that are quite different from conventional allocation studies. Even here, I will not attempt to respond to each point of difference – but instead will focus my attention on the area of greatest significance – which is the allocation of production and transmission system costs. I will first respond to the study offered by the OPC, and then will address the study sponsored by Staff.

Summary of Rebuttal Testimony

Q PLEASE SUMMARIZE THE PRINCIPAL POINTS AND CONCLUSIONS IN YOUR REBUTTAL TESTIMONY.

A My principal points and conclusions can be summarized as follows:

1. The allocation method employed by OPC gives far too little weight to demands occurring during the summer months, and far too much weight to demands occurring during non-summer periods as well as to annual energy consumption. Accordingly, OPC's cost of service study does not reflect cost causation for the Empire system and should be rejected.

2. The cost allocation model sponsored by the Commission Staff is fraught with problems and should be rejected. More particularly, it suffers from the following problems:

   a. The study merely scales up class allocation factors from Empire's last case, despite the fact that there are significant changes to Empire's generation system.

   b. All of the allocations of fuel and capacity cost to individual hours in Staff's model are derived from this hourly fuel cost model. The actual capacity cost of Empire's system is not derived from the model.

   c. The relationships produced by the model, between capacity cost and hours use of capacity are erratic and unstable, as shown by Schedules 1 and 2.

   d. The results produced by Staff's model are unrepresentative of the costs on the Empire system. For example, the capacity costs (before adjustment) produced by the model were less than 50% of Empire's actual generation capacity costs in the last case.

   e. Any relationship between the cost to serve Empire's customers and the results of Staff's model would be purely accidental.

   f. Staff's study treats interruptible customers inappropriately. The result is the estimated cost to serve the load on a firm basis, when, in fact, the load of Praxair is 95% interruptible.

3. The cost of service model produced by the Staff totally fails to address the cost of serving the lighting and furnace classes.

Response to Cost of Service Study Sponsored by Public Counsel

Q WHAT METHOD DOES PUBLIC COUNSEL USE FOR THE ALLOCATION OF GENERATION AND TRANSMISSION FIXED COSTS?

A According to the testimony of Public Counsel witness Hong Hu (Lines 5-18 on Page 4), the Public Counsel used what Ms. Hu describes as a 12-month non-coincident peak (NCP) "average and peak" allocation method.

Q WHAT IS THE BASIS FOR USE OF THIS METHOD?

A It is very difficult to tell from OPC's testimony and workpapers. All Ms. Hu says is that she believes this method would mimic the results of an undefined "time-of-use" method. This is the long and short of Public Counsel's support for its allocation methodology. No other part of Ms. Hu's testimony, and no part of the testimony of any other OPC witness, addresses the basis for selecting this allocation method.

Q DOES THIS METHOD MIRROR HOW UTILITIES INCUR COSTS?

A No. To answer this question fully, it is first necessary to understand the method which OPC used. There are two elements to OPC's customer class allocator. The first element is customer class annual energy use. This is simply total kilowatthours utilized by each customer class over the year. No distinction is made with respect to either the month in which kilowatthours are used, or the time of day when they are used. Annual customer class energy consumption receives a weighting of over 50% (56.16%) in OPC's allocator.

The second portion of the allocator (which has a weight of 43.84%) is based on a weighting of the monthly noncoincident demands of each customer class. The noncoincident peak demands are the highest demand of each customer class in each month. The time of occurrence of the peaks during each month is ignored for purposes of this portion of the allocation factor. Thus, a class demand occurring at 3 o'clock AM has the same weighting in the allocation as a class demand occurring coincident with the afternoon system peak demand–even though the implications for capacity additions are quite different. Loads imposed on the system during off-peak hours make essentially no contribution to the need to add transmission or generation capacity–while loads imposed at or near the system peak clearly do. Thus, this aspect of OPC's allocation factor is also inaccurate–in the sense that it does not use factors which determine how costs are caused on a utility system.

Continuing with this second portion of the allocation factor, the monthly non-coincident class demand percentage (each classes' noncoincident peak is divided by the sum of the noncoincident peaks of all classes in the same month to determine the percentage that each class is to the total), is then weighted by another percentage which is derived from an analysis of the level of utility system monthly peak demands. The result is that the two summer peak months (July and August), which have loads far in excess of loads in other months, receive a weighting of only about 32% under Public Counsel's method. Even adding the other two summer months (June and September) produces a weighting of these four summer months of only 50%. This means that the eight other months receive a weighting of 50%, even though the highest peak load in those other months is only 85% of the annual peak load, and the average of the loads in these other eight months is less than 66% of the annual system peak.

Considering the combined effect of the heavy weighting given to energy, and the heavy weighting given to loads in non-peak months, less than 15% of the value of the allocator is attributable to demands occurring in the two summer peak months, and less than 25% of the value of the allocator is driven by loads in the four summer peak months. As explained in detail in my direct testimony, the Empire system has a predominant summer peaking load characteristics. Allocation methods such as OPC has created, that give significant weight to loads occurring in off-peak hours and in off-peak months, have no claim to accuracy or the representation of cost causation because the summer peaks drive the need for capacity additions. Accordingly, OPC's study should be rejected.

Q HOW DOES THE "AVERAGE AND PEAK" METHOD ADVOCATED BY PUBLIC COUNSEL DIFFER FROM THE "AVERAGE AND EXCESS" METHOD WHICH YOU HAVE USED IN YOUR TESTIMONY?

A The difference is significant. The average and excess method considers the allocation in two steps as well, and the first step is average demand or energy consumption. However, the second step is not total peak demand, but is the difference between average demand and customer class peak demand. This gives appropriate weighting both to energy consumption and to peak loads. The average and excess method also is widely accepted in the industry. In fact, the average and excess demand allocation method and the coincident peak allocation method (both with their variations) are the two most widely used allocation methods in the electric utility industry.

Continuing with the contrast between average and excess and OPC's average and peak allocator, the average and peak allocator uses both average demand and customer maximum demand–not the difference between average demand and maximum demand. As a result, OPC's average and peak method double-counts average demand because average demand is a component of peak demand. Thus, average demand is counted twice – once in the first step of the development of the factor which uses average demand, then again in the second step when use is made of the total peak demand, rather than the difference between peak demand and average demand. This double-counting of average demand is wrong and substantially skews the results against high load factor customers–as is evident from the results produced by Public Counsel's study.

Response to Cost of Service Study Sponsored by the Staff of the Missouri PSC

Q AT PAGE 3, LINE 4 OF HIS DIRECT TESTIMONY, MR. WATKINS STATES THAT HE ALLOCATED PRODUCTION COSTS TO CUSTOMER CLASSES BY "THE" TIME-OF-USE METHOD. IS THERE A SINGLE TIME-OF-USE METHOD?

A No. Unlike the terms "average and excess" and "coincident peak," the term "time-of-use" does not define a particular method or approach for analyzing or allocating costs. The method which Mr. Watkins has used is, as far as I can tell, unique to the Missouri PSC Staff. **The method which Mr. Watkins used is not described in the NARUC cost allocation manual, nor have I seen this particular method used in any other jurisdiction.**

Q WHAT IS YOUR OVERALL ASSESSMENT OF THIS METHODOLOGY?

A In my opinion, it does not properly reflect cost causation. It allocates generation and transmission capacity costs across all hours of the year, even though many hours of the year are off-peak and loads are at such low levels that they would not cause the need for the addition of generation or transmission capacity.

Q AT PAGE 3 OF HIS TESTIMONY, MR. WATKINS GIVES AS A JUSTIFICATION FOR HIS ALLOCATION METHOD THE FACT THAT UTILITIES CAN CHOOSE

FROM DIFFERENT TYPES OF GENERATING UNITS THAT HAVE DIFFERENT COST CHARACTERISTICS. DOES THIS JUSTIFY HIS ALLOCATION APPROACH?

A No. Mr. Watkins references the fact that there are several available generation technologies, which he summarizes into the categories of base, intermediate and peaking. Clearly, these facilities have different capital costs and different fuel costs. But, he does not provide a justification which links his particular allocation method to these characteristics. Certainly, the fact that there are different technologies does not justify allocating capacity costs to every hour of the year.

Q PLEASE EXPLAIN.

A At the first level, it is true that utilities select the mix of generation facilities that they expect to be able to produce power at the lowest overall total cost, taking into account the combination of fixed costs and variable costs. Having made that decision, the amount of fixed costs on the system is set, and does not vary with kilowatthour output or the number of hours that the facility is operated. These are truly fixed costs, which traditional allocation methods would treat as demand-related costs and allocate to customer classes based on a method such as average and excess or coincident peak. The types of fuel used are defined by the specific technology employed, but the total fuel cost varies as a function of total kilowatthour output–and thus is treated as a variable cost. Typically, the variable costs are allocated on the basis of the total annual kilowatthours required by the various customer classes.

Q IS THIS TECHNOLOGY DISTINCTION IMPORTANT FOR PURPOSES OF PERFORMING CLASS COST ALLOCATION STUDIES?

A No, it is not. While it is recognized that the different technologies have different combinations of fixed and variable costs, any distinction that would attempt to more precisely articulate costs by customer class would require an analysis to determine the technology or technologies that would be installed if a utility served each customer class independently, at its lowest cost. The result would be that for high load factor customer classes relatively more base load plant would be installed, and relatively less peaking plant would be installed. The converse would be true for lower load factor customers. If this were done, then the high load factor class would be allocated more fixed costs, but less variable costs; and the low load factor customer class would be allocated less capital costs but more fuel costs.

This allocation would reflect the trade-off between capital costs and fuel costs inherent in Mr. Watkins statement on Page 3. If this specific analysis were done for each class on a stand-alone basis, then the results of this analysis would have to be analyzed to determine how to apply them to the actual fixed and variable costs which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its total load at the lowest total (fixed plus variable) cost. If the desire is to more specifically reflect these technology tradeoffs, then this type of analysis would be required. The type of analysis that Mr. Watkins performed has not appropriately captured these considerations.

Q HOW DO TRADITIONAL COST ALLOCATION STUDIES RECOGNIZE THIS MIX OF TECHNOLOGIES?

A Traditional cost allocation studies recognize that the mix or combination of plants is built to serve the overall or combined load characteristics of all customer classes – and not for the load characteristics of any particular customer class. They, therefore, allocate energy costs equally across all customer classes on an equal cents per kilowatthour basis, and allocate fixed costs equally across all customer classes on a uniform dollars per kilowatt of demand basis. This approach is reasonable, and avoids a lot of complexity and speculation that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q ARE THERE OTHER REASONS WHY IT IS INAPPROPRIATE TO INCLUDE CAPITAL COSTS IN ALL HOURS OF THE YEAR?

A Yes. In considering the different types of technologies available, the trade-off between variable costs and capital costs occurs at some specific number of hours of operation. Beyond the hours of operation where there is a "break-even" between the two different technologies, additional hours of operation of the more capital intensive plant does not change the decision of what type of technology to install. Thus, it is only hours up to that point which could even arguably make a difference in technology choices.

Q CAN YOU ILLUSTRATE?

A Yes. Assume Technology A has a capital cost of $500 per kilowatt, a heat rate of 7,000 Btu per kilowatthour, O&M expense of 0.3¢ per kilowatthour, and that it is fired with natural gas at a delivered cost of $4.00 per MMBtu. The total of fuel and O&M expenses would be 3.1¢ per kilowatthour.

Assume that a second technology has a capital cost of $300 per kilowatt, a heat rate of 12,000 Btu per kilowatthour and O&M expenses of 0.3¢ per kilowatthour. With the same fuel price, the total variable cost of this unit would be 5.1¢ per kilowatthour. The difference in variable cost is, therefore, 2.0¢ per kilowatthour (5.1¢ - 3.1¢). Assuming a carrying charge rate of 15%, the difference in capital cost is $30 per kW (the $200 per kW difference in capital cost times 15%). The break-even point (the hours of operation required for the lower fuel cost to out weigh the higher capital cost) is 1,500 hours ($30 ÷ $0.02). This illustrates that only slightly more than 15% of the hours in the year (1,500 out of 8,760) are arguably important in the technology choice question. Since the additional hours are not relevant in this decision – it is wrong to include loads in those additional hours in the cost allocation process – because those loads had nothing to do with the incurrence of the capital cost. The cost allocation methodology used by Mr. Watkins suffers heavily from this problem because he assigned capital costs to <u>all</u> hours of the year.

Q YOU HAVE ADDRESSED THE STAFF'S STUDY FROM A CONCEPTUAL POINT OF VIEW IN TERMS OF COST CAUSATION. ARE THERE SPECIFIC ELEMENTS OF THE STAFF COST OF SERVICE STUDY THAT YOU WOULD ALSO LIKE TO ADDRESS?

A Yes. Much of the following discussion is based on workpapers supplied by Staff in support of its cost of service study, as well as direct discussions with Mr. Watkins.

Q WHAT WAS THE STARTING POINT FOR STAFF'S DERIVATION OF ITS PRODUCTION ALLOCATION FACTORS?

A The starting point was a production cost simulation which was performed in Case No. ER97-81. (Staff did not perform a current analysis in this case, despite major changes in Empire's generation mix.) Based on information supplied by Mr. Watkins, it appears that a dispatch of Empire's capacity was performed against a system load curve with the objective of determining total fuel cost for each hour. In the model each hour was considered independent of each other hour – which means that whether or not a plant was running in the previous hour had nothing to do with whether or not it can be dispatched in the current hour, a significant departure from reality.

From this model output – which produced fuel costs by hour, Staff constructed an equation to make fuel cost a direct and increasing function of load level. When the hourly costs from the model were added up, the total of the hourly costs for all hours was approximately $58 million.

Q WHAT WAS THE NEXT STEP?

A The next step was to rank all hours in the year starting with the highest load, and continuing down to the lowest load. The fuel equation was applied to the loads to determine the predicted fuel cost in each hour. A calculation was then made to compare the predicted fuel cost in each hour with the predicted cost in the hour below it. This difference in cost was then divided by the difference in the loads between the two hours to create an "incremental" cost of fuel per megawatt of incremental load. Then, the difference in the incremental cost per megawatthour from one hour to the next was determined for each hour. This difference in incremental fuel cost was then multiplied by a "load duration." The load duration reflects the "count" or number of hours that the hour in question is below the peak hour. For example, the difference in incremental fuel cost between the first hour and the second hour was calculated by Mr. Watkins to be 3¢ per megawatthour. This was the second hour down from the top, so it was multiplied by two, producing 6¢ which Mr. Watkins represents as the "difference in dollar per MW capacity costs between load levels."

Q ARE THESE INCREMENTAL COSTS OF FUEL OR CAPACITY SMOOTH OR RELATIVELY UNIFORM FUNCTIONS?

A No. Schedule 1 is a graph of the difference in dollars per megawatthour fuel cost between load levels (on the vertical axis) versus megawatts of load (on the horizontal axis). Even though the hourly fuel cost dollars were produced from a mathematically smoothed curve that made the fuel cost a uniform, increasing, function of load, the incremental fuel cost numbers that Mr. Watkins derives from his analysis are quite erratic. For example, the value for the first hour is 3¢ per megawatthour. The cost of the next hour increases by a factor of four to 13¢ per megawatthour. Two hours later, it drops back to 3¢. A similar erratic pattern is exhibited by subsequent hours.

Schedule 2 is a similar graph of the difference in capacity cost between load levels as a function of the load duration. This is even more erratic than the incremental fuel cost function shown on Schedule 1.

The erratic nature of these results highlights the unrealistic nature of the approach Mr. Watkins has taken. In reality, costs do not vary in the manner indicated by this model. For example, capacity costs exist because there is physical plant. They do not exist on an hourly basis as the Watkins model suggests.

Q WHAT WAS THE NEXT STEP IN STAFF'S ALLOCATION?

A The next step was to develop an hourly array of "dollars per MW capacity cost at each load level." This is accomplished by a formula where the load in the highest hour has a value of $22,673, and the load in each successive hour is assigned a cost equal to the load in the prior hour plus the incremental capacity costs. These hourly values are then divided by the duration number which I described earlier. Then, "capacity costs" are totaled up starting with the lowest hour and moving up to the highest hour by adding, to the prior hour, the dollar per MW per hour capacity costs calculated for each load level times the product of the change in the megawatt load from hour to hour. The total of these hourly values is approximately $48 million, which is supposedly the amount of generation fixed costs in the Empire cost of service study at that time.

Q DO THESE NUMBERS ADD UP TO $48 MILLION?

A No. These numbers add up to that amount only because Mr. Watkins forced them to do so by plugging in the number of $22,763 not only in the first hour that I discussed earlier, but also in all other hours. If this "plug" number were not inserted, the capacity costs would only add up to approximately $28 million, less than one-half of their actual value! Thus, over 50% of the capacity cost from the model is the result of an "adjustment" that is required to fit the results of the theoretical analysis to the total actual capacity costs.

Q DOES THIS THEORETICAL MODEL HAVE ANY RELATIONSHIP TO THE ACTUAL COSTS OR CHARACTERISTICS OF THE EMPIRE SYSTEM?

A Obviously not. The only input data for this model (except the externally determined total capacity and energy costs for the Missouri jurisdiction–which were determined by a completely separate process) was the result of the hourly fuel cost model which I discussed at the outset. As noted, this is based on greatly simplified assumptions, and is therefore not representative of actual operations. The remainder of the analysis is based strictly on calculations using differences between incremental fuel costs and load levels. The capacity costs associated with Empire's generation capacity are not considered at all in this analysis!

This analysis hypothetically assumes some kind of optimality and a continuous trade-off between capital costs and fuel costs that does not exist in reality. Any relationship between the model results and the cost of serving customers on the Empire system would be purely accidental.

Q MOVING ON TO ANOTHER ASPECT OF THE STUDY, HOW ARE INTERRUPTIBLE LOADS TREATED?

A In Staff's study interruptible loads are treated the same as firm loads in the cost allocation. The sales to Praxair are re-priced at firm rates, and the additional revenues are then allocated across all customer classes. Staff's approach has the effect of charging back part of the cost of the interruptible credits to Praxair, which reduces the rate of return for Praxair. More fundamentally, Staff's approach determines the cost to serve interruptible customers as if they were firm – which they are not.

Q DID STAFF PERFORM A COST OF SERVICE STUDY FOR THE LIGHTING CLASS?

A No. Staff ignored the lighting class and essentially allocated the costs associated with serving the lighting class to other customer classes, and then allocated the lighting revenue back to those other customer classes. Accordingly, Staff's study does not reveal anything about the cost of serving the lighting customer class. Nor has the allocation of the costs which otherwise would go to the lighting class been explained or justified. The same treatment was applied to the power furnace class.

Q HOW DID STAFF ALLOCATE TRANSMISSION COSTS?

A These costs were allocated essentially in the same way as production-capacity costs, using the method which I previously described.

Q MR. WATKINS STATES ON PAGE 5 OF HIS TESTIMONY THAT TRANSMISSION PLANT IS GENERALLY CONSIDERED TO BE AN EXTENSION OF THE

PRODUCTION PLANT AND THEREFORE IT IS LOGICAL TO ALLOCATE THEM IN THE SAME MANNER. DO YOU AGREE?

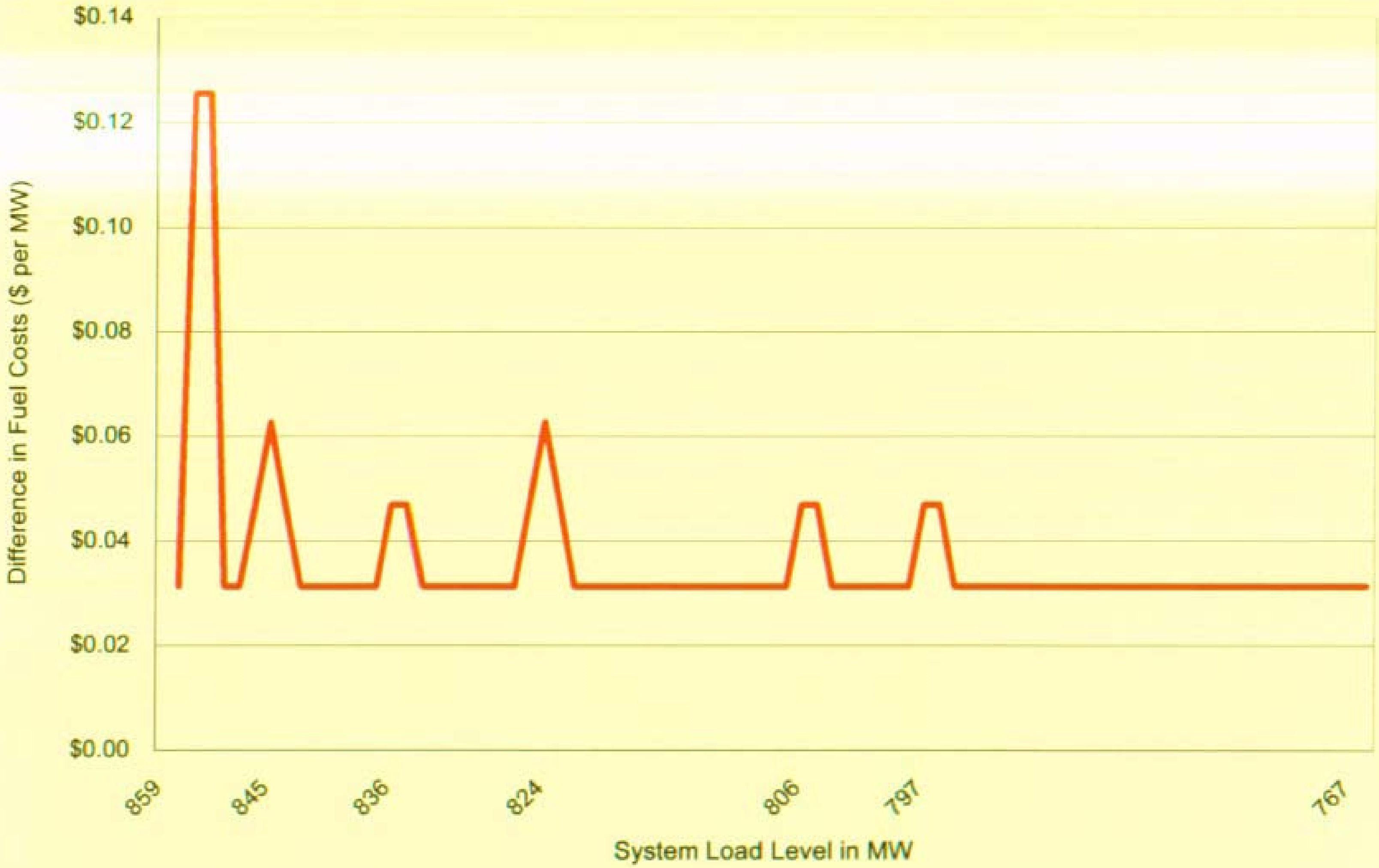
A No. In my view there should be an independent assessment of the cost causing features for both generation and transmission. It is not necessary that they be allocated in the same fashion. For example, the basic rationale for Staff's allocation of generation plant is the trade-off between fixed and variable costs that exists among generation technologies. This trade-off does not exist in the case of the transmission system. Transmission systems are sized with peak loading requirements as the primary factor. There are generally not choices between types of transmission lines or installations that contain the fixed/variable trade-offs that exist in the case of production plant. Thus, even if it were to be concluded that some form of energy-related allocation of production plant were appropriate, the same considerations do not apply to transmission facilities. Transmission investment should be allocated based on summer peak demands, regardless of how generation facilities may be allocated.

Q **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A Yes, it does.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Staff Allocation Model: Difference in Incremental Fuel Cost as a Function of Load Level



Schedule 1

THE EMPIRE DISTRICT ELECTRIC COMPANY

Staff Allocation Model:
Capacity Cost as a Function of Load Duration

THE EMPIRE DISTRICT ELECTRIC COMPANY

Staff Allocation Model:
Capacity Cost as a Function of Load Duration