STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Keyspan Gas East Corporation for Gas Service.	Case 16-G-0058
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the Brooklyn Union Gas Company for Gas Service.	Case 16-G-0059

REBUTTAL TESTIMONY

OF

UIU RATE PANEL

Dated: June 10, 2016
Albany, New York

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I. INTRODUCTION AND OVERVIEW

Q. Would the Utility Intervention Unit ("UIU") Rate Panel please state their names and business address?

A. **(Johnson)** My name is Ben Johnson, and my business address is 5600 Pimlico Drive, Tallahassee, FL 32309.

(Panko) My name is Danielle M. Panko and my business address is 99 Washington Avenue, Suite 640, Albany, NY 12231.

Q. Are you the same panel members that filed direct testimony on May 20, 2016?

A. Yes, we are.

Q. Have you prepared any exhibits to be filed with your rebuttal testimony?

A. Yes, Exhibit ___ (URP–4) and Exhibit ___ (URP–5) accompany our rebuttal testimony.

Q. Please describe your Exhibits.

A. Exhibit ___ (URP–4) contains information pertaining to Keyspan Gas East Corporation ("KEDLI") and Exhibit ___ (URP–5) contains analogous information relating to Brooklyn Union Gas Company ("KEDNY") (together, the "Companies"). Schedule 1 of Exhibit ___ (URP–4) compares the revenue allocation proposed by the Company to that proposed by the Department of

Public Service ("DPS") Staff Gas Rates Panel in their direct testimony. Schedule 1 also illustrates the revenue allocation we recommend using in this proceeding. Schedule 2 provides a summary comparison of the ECOS results and effective rate per therm for various KEDLI customer classes. It also provides a summary rate comparison of the firm and non-firm classes. Schedule 3 compares the rates proposed by KEDLI with the rates proposed by the Staff Gas Rates Panel, and rates we developed to illustrate the effect of our revenue allocation and rate design recommendations. Finally, Schedules 4 – 6 provide similar comparisons in the context of typical bills – showing the amount that would be paid each month by typical customers – thereby providing further insight into the impact of the positions taken by KEDLI, the Staff Gas Rates Panel and UIU with respect to various ECOS, revenue allocation and rate design alternatives.

Exhibit ___ (URP-5) contains schedules that are similar to Exhibit ___ (URP-4), except they contain information related to KEDNY's gas delivery service, and Schedule 1 of Exhibit ___ (URP–5) includes an additional page that shows the revenue allocation proposed by the City of New York ("City").

Q. What is the scope of this testimony?

A. We are providing UIU's response to the direct testimony of the Staff Gas Rates Panel, Mr. Richard Baudino on behalf of the City, Mr. John Dowling on behalf of Consumer Power Advocates ("CPA") and Spring Creek Towers, and Ms. Barbara Tillman on behalf of Spring Creek Towers. In the event that we do not respond to specific issues raised, or statements made, by these witnesses (or others), that should not be construed as agreement with those statements.

II. EMBEDDED COST OF SERVICE

Q. A significant portion of your direct testimony concerned the Companies' ECOS studies. Did other witnesses also discuss these studies?

A. Yes. Mr. Baudino, who testified on behalf of the City, offered the most extensive testimony. He endorsed the Companies’ approach to classifying and allocating distribution gas mains (which we disputed) and concluded that:

> The Companies' ECOSS provides a reasonable basis for cost and revenue allocation in this proceeding and is consistent with prior Commission decisions that adopted an allocation of distribution mains on a demand and customer basis.
>
> (Direct Testimony of Richard Baudino, p. 10.)

None of the other witnesses testified extensively concerning the cost studies. The DPS Staff witnesses briefly described the studies filed by the Companies and indicated they “do not necessarily agree” with the method used to classify and allocate distribution gas mains, which we extensively criticized in our direct testimony. However, they go on to say that:

> Based on our revenue allocation and rate design recommendations, however, we do not take issue with the studies’ results.
>
> (Direct Testimony of Staff Gas Rates Panel, p. 43.)

The witnesses testifying on behalf of CPA and Spring Creek offered even less detail in their comments concerning the Companies' ECOS studies.

Q. Your direct testimony included an extensive discussion of the costs which are sometimes associated with the concept of a hypothetical "minimum system." Did Mr. Baudino discuss this?

A. Yes. He endorsed the Companies' classification and allocation of distribution gas mains, noting with approval the Companies' claim that "distribution mains are installed to connect customers to the distribution system and to provide capacity to meet the winter peak". He said the Companies "appropriately utilized a minimum size system study to estimate which portions of distribution mains are demand related and customer related". (Direct Testimony of Richard Baudino, p. 10.)

Q. Did Mr. Baudino provide detailed evidence or reasoning to support his position?

A. He did not provide a detailed rationale. He based his conclusion on three arguments:

(1) Some of the costs of distribution gas mains are incurred to connect customers to the distribution system.

(2) The Companies' ECOS study used a minimum size system study to estimate which portion of the costs of distribution gas mains are customer related.

(3) The Commission has previously adopted an allocation of distribution gas mains on a demand and customer basis.

Q. Do you agree with these three arguments?

A. No. While some aspects of these arguments might be correct, they do not provide a valid basis for concluding that the Companies' treatment of distribution gas mains is appropriate or superior to the alternatives we set forth in our direct testimony.

Mains Do Not Connect Directly to Customers

Q. Can you please respond in detail to the first of Mr. Baudino's arguments?

A. Yes. The first (and pivotal) argument is factually incorrect, or at least misleadingly worded. Distribution gas mains are not physically or economically distinct from the distribution system. One therefore cannot accurately say distribution mains "connect customers to the distribution system" in any meaningful sense, at least when speaking about ordinary customers who are connected under normal circumstances. To the contrary, as the name implies, distribution gas mains are themselves an integral part of the distribution system. In fact, the investment in mains represents a large fraction of the overall investment in the distribution system.

The caveat concerning "ordinary customers" was mentioned because there can be special circumstances where a new main is installed in order to reach a specific customer (typically a very large customer), but when this occurs, the customer will typically be required to make a special contribution toward the cost of the main, or provide adequate assurances that it will purchase enough gas to justify the added investment. Under ordinary circumstances, distribution gas mains are installed along streets to ensure that gas is available to anyone located along that street that might choose to become a customer in the future.

In normal circumstances, the cost of a distribution gas main is not dependent upon who may or may not become a customer, or how many businesses and households will become customers after the main is installed. To the extent there is a causal relationship between customers and mains, the relationship runs in the opposite direction: businesses and households decide to become customers because a main is installed near them, making it cost-effective for them to choose gas for some of their energy needs. Furthermore, the cost of a main is not dependent upon how many customers are expected to use the main, but rather it is dependent upon how much gas is expected to be delivered through the main (particularly during peak times).

In general, the most important factors that determine the cost of any one distribution gas main are (1) how long it is (the length of the pipe) and (2) how much gas it needs to accommodate under peak loads (the diameter of the pipe). Because of the latter factor, it is fair to say that distribution gas mains are designed and engineered to accommodate anticipated peak gas flows. On this basis, it is common practice to use a peak demand factor to allocate the costs of distribution gas mains on the basis of peak usage. This is similar to how other parts of the classification and allocation process are handled, where a factor of particular importance is selected and used to classify and allocate costs, despite the fact that the factor in question is not the only one that influences the costs in question.

Fixed Costs Are Not Necessarily Customer-Related

Q. Can you please explain your reaction to the second of Mr. Baudino's arguments?

A. Yes. We do not agree with Mr. Baudino's characterization of the Companies' minimum size system study, because that study does not actually provide an estimate of costs that are a function of, or primarily related to, the number of customers. Rather, it provides an estimate of what portion of the costs of the Companies' distribution gas mains is fixed and what portion is variable (i.e., the portion that is not attributable to the diameter of the pipes). While the costs in question can conceptually be separated into fixed and variable portions, the fixed portion is independent of the number of customers, as well as of the customers' size.

The mere fact that a cost can be disaggregated into fixed and variable portions does not imply that the fixed portion is customer-related, or that the fixed portion is causally determined by, or a function of, the number of customers. Nor does the mere fact that a particular cost is fixed provide a logical basis for concluding that the cost should be classified as customer-related, or recovered on a uniform per-customer basis. At least in the case of distribution gas mains, the fixed costs in question are incurred for the purpose of ensuring that gas is available to all locations along a particular street, or throughout a particular geographic area, independent of the number of customers or potential customers that are located along any given street, or the number of customers or potential customers located within any given geographic area.

A substantial investment is required to open a trench and install a main. That investment is primarily a function of the length of the main – how many feet of trenches that must be dug and how many feet of pipe that must be installed. (Another consideration is the nature of the difficulties that will be encountered along the route – electric lines, water and sewer lines and other obstacles that must be dealt with while installing the main.) By comparing the cost of different diameter pipes, the Companies have attempted to distinguish between fixed costs, which are independent of the diameter of the mains, and variable costs, which vary with the diameter of the mains. However, these fixed costs are not only independent of peak load carrying capacity – they are also independent of the number of customers that will be served by the main, the types of customers, or the size of those customers.

By labeling this fixed cost as “customer-related,” Mr. Baudino implies it is appropriate to classify and allocate these costs in proportion to the number of customers in each class, but he does not offer any supporting evidence or logic. Placing this “customer-related” label onto the minimum system does not change the fact that these are actually fixed costs that are <u>not</u> related to the number of customers. In fact, these fixed costs do not vary with, and are actually independent of, the number of customers. The cost of the minimum system is a function of the size of the system (miles of pipe) and the difficulties encountered in installing the pipe (installation cost per foot). It is independent of the number of customer locations along the route, or even the potential number of customers who could conceivably connect to the system in the future. Mr. Baudino's argument for using a minimum system analysis collapses under close scrutiny, because the costs in question do not vary as a function of the number of customers, and so there is no basis for concluding that they should be classified and allocated on the basis of the number of customers.

<u>Uniform Per-Customer Fixed Cost Recovery is Inequitable</u>

Q. Are you saying that recovering the minimum distribution system costs on a uniform per-customer basis would be inequitable?

A. Yes. Treating the fixed portion of these costs as customer-related and recovering them on a uniform per-customer basis would place an excessive and undue burden on individual residential and small commercial customers. This burden would be unjust and inequitable, as well as being inconsistent with the manner in which these types of costs are typically recovered in most unregulated markets (as discussed in our direct testimony). By comparison, recovering the cost of distribution gas mains through volumetric rates is a reasonable methodology that does not place an excessive share of the fixed costs on any particular class or category of customers.

Q. Can you please explain why you believe a uniform per-customer approach is inequitable?

A. Yes. To understand the problem, consider a simple hypothetical example, comparing a small business owner who operates a 1,000 square foot retail store in the “downtown” area of a large town on Long Island. In this example, the small retailer competes with several other retailers, including a 100,000 square foot “Big Box” retailer (like Home Depot or Wal-Mart), located a few miles out of town. The “Big Box” retailer enjoys many advantages, including a streamlined supply chain that enables it to sell at lower prices. But the small retailer also enjoys some competitive advantages, including a more personalized service and a wider variety of merchandise (within its particular area of specialization).

In this example, the “Big Box” retailer uses about 100 times more natural gas to heat its store (compared to the small retailer), but its peak demand is only 80 times as large. This translates into a moderate cost-advantage for the “Big Box” retailer, when comparisons are made on an apples-to-apples, per-square foot basis – a pattern that applies to most of the items included in their respective utility bills. This holds true for fixed costs when they are allocated using the demand-based methodology – the “Big Box” retailer is allocated a larger share of the distribution gas mains, in proportion to its larger peak demand, which works out to net 20% cost savings on a per-square foot basis.

In contrast, under the uniform per-customer method advocated by the City, the “Big Box” retailer would be allocated the same dollar share of these fixed costs as the small retailer, despite using 100 times more energy and having a peak demand that is 80 times larger. If this uniform per-customer methodology were accepted by the Commission and flowed through to bills, both stores would end up contributing the same exact dollar amount per month for this portion of their utility bill. This would clearly be inequitable, since one store is 100 times larger than the other, and it receives 100 times as much natural gas from the system. The inequitable nature of this cost allocation methodology becomes even clearer when their respective shares of the fixed costs are compared on an apples-to-apples basis: the “Big Box” retailer would pay 99% less per square foot than its smaller competitor.

Q. Your hypothetical example applies to KEDLI's service area. Does a similar concern apply to KEDNY's service area?

A. Yes. Very similar points could be made using the example of small retailer in Brooklyn who competes with a large department store down the street. It is fundamentally inequitable to expect the smaller store to contribute the same amount (in dollars) as its much larger competitor, merely because each store represents a single customer account on the utility's system, while ignoring the vast difference in size and the extent to which they use the system.

Considering that we are dealing with fixed overhead costs of the system that cannot be directly attributed to, and are not caused by, either store, an extreme disparity in cost burden would clearly be unfair and inequitable. To consider a simple analogy, it is hard to imagine anyone trying to argue that the smaller store should pay the same dollar amount of property taxes as the “Big Box” retailer. But, if someone did try this argument, the fact that the smaller retailer would be required to pay 100 times more per square foot than its larger competitor would surely dissuade the taxing authorities from accepting the argument. In reality, of course, the tax burden is spread much more equitably, because virtually all local, state and federal taxes are calculated as a function of property value, sales volume, income, or some other appropriate factor that varies with the size of the taxpayer – thereby ensuring that the tax burden is equitably spread across small and large firms.

Q. Does the same concern apply to residential customers?

A. Yes. If the minimum system approach were fully implemented in practice, KEDNY would collect the same amount for its fixed (“minimum system”) costs from a 400 square foot studio apartment constructed in Brooklyn shortly after World War I as it would collect from a brand-new 3,500 square foot luxury apartment overlooking the East River – notwithstanding the fact that the latter apartment uses more than five times as much gas, and the City collects ten times more property taxes from the latter apartment to help cover the City's analogous fixed infrastructure costs.

The anomalies and inequities associated with the minimum system approach endorsed by the City's witness do not stop there. Under the minimum system approach, the amount of fixed costs recovered from a 10-unit apartment building could end up being <u>more</u> than the amount recovered from a much larger 100-unit apartment building down the street. This would occur where the landlord of the larger building obtains gas for all of its tenants through a single meter so each tenant counts as only 1/100th of a “customer,” while the owner of the smaller building installs separate meters for each unit, so that each apartment in the smaller building is billed as a separate individual customer. From these examples, it is clear that equitable treatment cannot be achieved if the fixed costs are allocated and recovered on an equal per-customer basis, without any consideration of how large or how small different customers are, or how much or how little they use the system.

<u>Prior Commission Decisions</u>

Q. Let's turn to Mr. Baudino's third argument. Is it true that this Commission has previously accepted an allocation of distribution gas mains based on both demand and customers?

A. Yes; however, those earlier cases need not and should not control the outcome of these cases. Where an issue is in controversy, as in this situation, we would ask the Commission to weigh the evidence provided by the parties in order to determine which approach is most appropriate and consistent with the public interest, based on the evidence before it in that proceeding. That is especially true in a situation like this, where facts and evidence are being brought to the Commission's attention which may not have been available, or as fully explained, in those earlier proceedings.

While the Commission has, on occasion, accepted proposals to classify distribution gas main costs partly as demand-related and partly as customer-related, it has also accepted proposals to classify distribution gas main costs as entirely demand-related. Putting the fixed portion of the cost of distribution gas mains into the customer classification has been a controversial practice since at least the 1980's, and it remains a controversial practice to this day, as we will discuss later in our testimony. While we realize the Commission has sometimes accepted this approach, we do not believe those past decisions should preclude consideration of the many problems that exist with the minimum system approach.

In fact, looking at the decision in the 2008 Central Hudson rate proceeding (Cases 08-E-0887 et al.) that was cited by Mr. Baudino, we see that the decision was based upon the evidence that was brought forward in that particular case, and the Commission did not attempt to resolve the issue in a definitive manner that would control all future cases. To the contrary, the controversy in that case was largely resolved on the basis of the Commission's preference for rate continuity and the desire to avoid potential customer impacts that might result if it were to change allocation methods from what was historically the practice of that utility. The Commission explained its reasoning as follows:

> Staff proposed to reclassify gas distribution main costs for purposes of the pro forma embedded cost of service study by assigning them entirely to the demand component of rates. [This] reclassification results in a very large shift in cost responsibility from residential customers to large gas users. The RD noted that both the existing and proposed methodologies are deemed acceptable by NARUC with no indication that one or the other is superior. It concluded that such a large shift in cost responsibility should not be adopted without compelling evidence that it is necessary to rectify some serious inequity.
>
> (Order Adopting Recommended Decision With Modifications, pages 46-47.)

Given the totality of the circumstances here, it is more appropriate to classify distribution gas mains as entirely demand-related, and to recover these costs through the per-therm rates. This will thereby ensure that larger customers contribute a larger share of the costs of the system, consistent with the fact that they use the system more intensely and get more benefit from the system than small customers.

<u>Decisions in Other Jurisdictions</u>

Q. Has the Minimum System approach been universally accepted in other jurisdictions?

A. No. This costing approach has been under debate for more than 30 years, and the results of such debate have varied widely. The debate has been carried out sporadically across multiple jurisdictions and many years. In many cases the issue was not debated, and thus it is not readily apparent whether the approach was used, or how it would have been dealt with if the issue had come to the forefront.

Overall, it is fair to say that the Minimum System Approach is not universally accepted by either utilities or regulators. Where it has been discussed, it has often been very controversial. Even when it has been accepted, it had not necessarily been fully relied upon. Some utilities may analyze their costs based upon a hypothetical Minimum Distribution System ("MDS") or a statistically-based variant of the concept called the zero-intercept ("ZI") method, but they do not fully implement the concept in developing their actual revenue allocation and rate design proposals. Other utilities choose not to prepare this type of analysis, and instead classify and allocate all of the distribution accounts in question based 100% on demand, as we are recommending in these cases.

Similarly, some state regulatory commissions may accept filings that include a minimum system analysis, but may not necessarily accept or reject the results, or may ignore or give little weight to the results when developing the actual revenue allocation and rate design they ultimately approve. In fact, the same jurisdiction may resolve the issue one way in one case, and another way in another case – depending upon the circumstances in each case, including how the issue was presented to it, and what evidence was available. Similarly, the issue might be resolved one way in the context of class allocations, and another way in the context of rate design. Examples of such state regulatory commission decisions are presented later in our testimony.

This diversity of results can be gleaned to a degree from a careful reading of the May 28, 2015 report by the American Gas Association ("AGA"), which we cited in our direct testimony. That report includes distribution gas mains in its list of "fixed" costs, but it goes on to note that many utilities recover only "a portion of these costs through a fixed charge on the customer's bill. This is most often called the 'customer charge,' but it is also called minimum bill. . . ." (AGA Energy Analysis Report, page 1.) The report explains that cost recovery policies vary widely across utilities and jurisdictions, and concludes that, on average "[t]he customer charge . . . typically recovers only 46 percent of a utility's actual fixed costs. . . ." (AGA Energy Analysis Report, page 2.)

The data provided in Appendix 1 to the AGA report shows that as of 2015, customer charges spanned a wide range both across jurisdictions and within jurisdictions. The report includes many examples from around the country where gas utilities have much lower customer charges or minimum bills than KEDNY and KEDLI, including: AGL – Florida City Gas in Florida ($8.00), Alliant –

Interstate P&L in Minnesota ($5.00), Avista Corp in Idaho ($8.00), Avista Corp in Oregon ($4.25), Centerpoint Arkla in Arkansas ($9.75), Chesapeake Utility Corp in Maryland ($8.75), Coserv Gas in Texas ($7.00), Dominion – Hope Natural Gas in West Virginia ($8.99), Integrys – Wisconsin Public Service Corp in Michigan ($5.00), Liberty Utilities in Iowa ($7.95), Liberty Utilities in Illinois ($9.90), Middle Tennessee Natural Gas Utility District ($7.00), Montana-Dakota Utilities in North Dakota ($3.50), Montana-Dakota Utilities in South Dakota ($8.40), Northwestern Energy in Montana ($7.30), Northwestern Energy in Nebraska ($8.00), Piedmont Natural Gas in North Carolina ($10.00), Public Service Electric and Gas in New Jersey ($5.46), Questar Gas in Utah ($6.75), Sempra – Southern California Gas in California ($4.90), UGI Penn Gas in Pennsylvania ($2.19), Washington Gas Light in the District of Columbia ($9.90), Wisconsin Power & Light ($1.51), and many others. Given monthly rates like these, it is clear that many regulators are either rejecting the Minimum System concept, or they are largely ignoring it when deciding what actual rates to charge customers.

Q. Are you aware of any cases in New York where the utility did not use the Minimum System approach?

A. Yes. In Case 01-G-1668, New York State Electric and Gas Corporation (“NYSEG”) classified and allocated 100% of the cost of distribution gas mains based upon demand (0% weight was given to the number of customers). Similarly, there is evidence that Rochester Gas and Electric Corporation

("RG&E") have been using 100% weight to demand in analyzing distribution gas mains for several years. More recently, these utilities proposed 100% weight to demand in 2009 in Cases 09-G-0716 and 09-G-0718, and again in 2015 in Cases 15-G-0284 and 15-G-0286.

Q. Are you aware of any cases in New York where the Minimum System approach was not accepted by DPS Staff?

A. Yes. In Case 06-G-1185 and Case 06-G-1185, involving KEDNY and KEDLI, DPS Staff recommended giving 100% weight to demand, despite the fact that the utility had developed a Minimum System Analysis. DPS Staff's stated rationale was to "more closely identify the minimum customer costs for each service class". (Direct Testimony of Aric Rider, page 15.) More recently, in Case 14-G-0494, a 2014 proceeding involving Orange and Rockland Utilities, the DPS Staff Gas Rates Panel recommended "allocating the costs of the distribution gas mains system on a 100% demand and 0% customer basis" despite the fact that the utility had developed a Minimum System Analysis. (Staff Gas Rates Panel, p. 23.) DPS Staff's position in the Orange and Rockland gas case was ultimately adopted by the Commission.

Q. Can you provide a few examples of cases where the Minimum System approach was rejected in other states?

A. Yes. One example is from Massachusetts, where the concept was advocated by an intervenor but rejected by the Massachusetts Department of Public Utilities:

> The Consortium contests the Company's classification of distribution mains as entirely capacity-related (id., p. 10). The Consortium presented Alan Rosenberg, a consultant with Drazen-Brubaker Associates, Inc., to support its capacity classification and allocation arguments . . . .
>
> The Consortium proposed that the Company conduct a study to identify and classify a minimum portion of distribution mains as customer-related . . . The Department has reviewed and rejected a similar argument in Colonial Gas Company, D.P.U. 84-94, pages 73 and 77-78 (1984) (“Colonial”).
>
> In Colonial, the Department . . . found that the size of a distribution main is determined by the amount of gas that would be sent through a particular main during the peak time period. Id., p. 77. The Department found that distribution mains are capacity related . . . Moreover, the Department has previously found that the costs of distribution mains do not vary with the loss or the addition of a single customer. Western Massachusetts Electric Company, D.P.U. 20110-A, p. 13 (1982).
>
> The Department notes that a strong correlation between two variables does not necessarily indicate cost causation. Specifically, the fact that number of customers and length of mains are strongly correlated does not establish that number of customers is a significant factor relative to other factors in causing the Company to incur distribution mains costs. In this instance, the Department will not rely on a statistical measure without a demonstration that the hypothesis being examined is based on sound reasoning.
>
> The Department reaffirms its past findings and concludes that there is a cost causative relationship between loads and distribution mains. The Department finds that there is no need for the Company to conduct a study to identify

> and classify a portion of distribution mains as customer-related.
>
> (Order Dated October 31, 1991, DPU Case 91-60 (1991 WL 531844).)

Another example is this case in Illinois:

> The arguments of IIEC and Wal-Mart do not persuade the Commission to deviate from its past decisions and now embrace the MDS. The MDS method fails to properly emphasize the purpose of the distribution system — that being to satisfy a customer's daily demand for electricity. Ameren's method, on the other hand, does not suffer from this weakness. The Commission also continues to believe that distinguishing the cost of connecting customers to the distribution system and the cost of serving its demand remains problematic. Moreover, the Commission is hesitant to rely on the 1992 NARUC manual cited by IIEC and Wal-Mart because of its age and the changes in the electric industry. Accordingly, the Commission will not adopt the MDS in this proceeding. The Commission also declines to adopt IIEC's suggestion that Ameren be required to present a COSS in its next rate case incorporating the MDS approach. In the Commission's view, it would be unreasonable to require Ameren to perform a COSS that incorporates a method repeatedly rejected by the Commission.
>
> (Order dated November 21, 2006 (Ill. C.C.) (2006 WL 3863623).)

The Michigan Public Service Commission rejected the Minimum System concept in a 1989 case involving Consumers Power Company, choosing instead to use an allocation factor based upon average and peak (“A&P”) demand:

> Consumers and ABATE each proposed that a portion of Consumers' distribution mains — the minimum system — is customer related and should be allocated on a

> customer basis . . . The Staff proposed that all distribution mains be allocated pursuant to the A&P methodology.
>
> The ALJ determined that the Staff's allocation of distribution mains was reasonable and recommended its adoption by the Commission. In so doing, he noted the Commission's preference for the A&P allocation methodology and its recent rejection of the minimum system concept in Case Nos. U-8635, U-8812, and U-8854.
>
> . . . .
>
> The Commission finds the arguments raised by ABATE and Consumers are not persuasive. Any allocation methodology utilized by the Commission is, to some extent, arbitrary. Ideally, no customer should be assessed more than the exact cost of serving that customer. However, attaining this ideal standard would require a separate rate computation for each customer.
>
> In the final judgment, the question is not whether a more exact methodology can be constructed; rather the question is whether the method and result are reasonable. The Commission finds the method proposed by the Staff, which has been repeatedly utilized by the Commission in other cases, is an accepted and reasonable way to distribute the cost of Consumers' distribution mains. Accordingly, the exceptions filed by ABATE and Consumers are rejected.
>
> (Order dated December 7, 1989 in Case Nos. U-8678 et al. (1989 WL 418755).)

Another example involved Mountaineer Gas Company, where the West Virginia Public Service Commission weighed extensive arguments back and forth before ultimately rejecting the Minimum System approach:

> Staff takes issue with the Company's use of the minimum system approach for allocating distribution plant . . . Staff

> recommends using class peaks as a better method of allocation of the distribution mains.
>
> Mountaineer maintains that the minimum system methodology presented in its class cost of service study is the better method because: 1) it is consistent with good allocation principles; 2) it is recognized by NARUC and approved by several state Commissions . . . .
>
> Mountaineer disagrees with Staff and CAD's allegations that: 1) the minimum system is not based on cost causation; 2) that the minimum system places to much emphasis on number of customers; and, 3) that Mountaineer should allocate more of its cost based on through-put . . . .
>
> Similar to the return on equity and rate of return issue, the Commission is faced with the testimony and exhibits of well qualified experts on rate design and three separate class cost of service studies. In the final analysis, the adoption of any of the parties' recommendations is a matter of judgment. The Commission is persuaded by the CAD's arguments regarding the *Seaboard* formula of allocating distribution system cost. The Commission is further persuaded by Staff and CAD's arguments that Mountaineer's class cost of service study places undue emphasis on allocating costs on the basis of the number of customers, which tends to unfairly allocate more costs to the residential customer.
>
> (Order dated October 29, 1993 in Case No. 93-0005-G-42T (1993 WL 494175).)

Q. The Zero Intercept approach is sometimes offered as a compromise – a less objectionable alternative to a traditional Minimum System analysis. Can you describe the Zero Intercept Approach and provide some examples where this option was discussed?

A. Yes. One way of understanding the Zero Intercept Approach is to think of it as a variation of the Minimum System Approach, which focuses on an even more extreme hypothetical concept: a system consisting of mains with an interior diameter of 0 inches. These pipes are still very costly to purchase and install, but they cannot carry any actual gas. In practice, the Zero Intercept approach is developed by applying statistical techniques to the historical cost data, in an effort to distinguish between the fixed and variable components of the installed cost of mains. While it might be offered as a compromise or less objectionable approach, it is still controversial, and depending on the adequacy of the data and the specific statistical technique applied, it can result in cost estimates that are actually larger than the standard Minimum System Approach.

In a 2002 case involving Gulf Power Company, the Florida Public Service Commission rejected both versions, explaining their reasoning as follows:

> The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load. There is no real equipment that equates to the costs identified by the ZI methodology. We have rejected MDS in the past for this very reason.
>
> (Order No. PSC-02-0787-FOF-EI dated June 10, 2002 in Docket No. 010949-EI (2002 WL 1349501).)

That decision referred to the Florida Public Service Commission's history of rejecting the method, citing an example from more than 20 years earlier, where it had explained its fundamental discomfort with the concept:

> The Company and staff have proposed the use of a theoretical minimum distribution cost . . . we do not agree that a theoretical cost of a minimum distribution system is appropriate . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. Reliance on such a mechanism is speculative at best.
>
> (Order 9599, issued October 17, 1980 in Docket No. 800011-EU.)

A similar decision was made in a 1984 case involving Puget Sound Power & Light, where the Washington Utilities and Transportation Commission rejected both options:

> The Commission rejects the company's use of the zero-intercept method. The minimum system method, of which the zero intercept method is a variant, is also rejected. Both methods are likely to lead to the double allocation of costs to residential customers and over allocation of costs to low use customers.
>
> (Order dated January 19, 1984 in Case No. U-83-26 (1984 WL 1022551).)

Q. Can you provide an example of a case where the Minimum System approach was accepted, yet the regulatory commission expressed reservations about the concept?

A. Yes. In a 1984 case involving Enstar Natural Gas, the Alaska Public Utilities Commission stated:

> Although the Commission finds the overall methodology used in the COS study to apportion distribution costs results in a fair allocation among the classes, the

> Commission believes that future use of a minimum distribution study . . . may unfairly burden the residential class. From an optimal ratemaking perspective, there should be a direct cause and effect relationship between any cost and the object to which that cost is being allocated. While COS studies give the impression that the above relationship is quite precise, this is seldom the case, particularly when attempting to apportion the distribution expenses of an integrated natural gas utility. Distribution costs in general do not always have a strong positive correlation, nor do they necessarily vary directly with the number of customers, the type of class, the demand, or the consumption of gas. In sum, distribution costs are joint-use expenses not subject to precise allocation. In the final analysis, the decision to allocate distribution expenses must be resolved by rather subjective policy decisions; the decision becomes a value judgment based on concepts of fairness, reasonableness, optimum pricing, etc., and not objectively measurable allocation criteria.
>
> For these reasons, the Commission is not persuaded that a major portion of distribution expenses, “justified” via a hypothetically derived minimum distribution study, should continue to be automatically assigned to the residential class via a customer component allocator . . . .
>
> (Order No. 6 in Case U-83-38, dated February 14, 1984.)

Q. Can you provide an example where a regulatory commission more firmly expressed its objections to the Minimum System approach?

A. Yes. About a decade after the Puget Sound case mentioned earlier, the Washington Utilities and Transportation Commission went even further in rejected it:

> The company proposed to classify distribution costs using the Basic Customer method, which treats substations, poles, towers, fixtures, conduit, and transformers as

> demand-related. Service drops and meters are classified as customer-related . . . .
>
> WICFUR and SWAP recommended use of the Minimum System approach. This would classify most distribution-related costs according to the relative number of customers in a class. WICFUR argued that this method better reflects the fact that a multitude of small customers requires a more extensive distribution system as compared to large customers with the same total energy requirements.
>
> The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.
>
> (Order dated August 16, 1993 in Docket No. UE-921262 et al (1993 WL 13812140).)

Q. Can you provide an example where the utility was actually required to perform a Minimum System analysis, yet the results were ultimately rejected?

A. Yes. This occurred in a 2009 electric case involving Public Service Company of Oklahoma:

> Pursuant to the Commission's Order in PSO's last rate case, Cause No. PUD 200600285, PSO performed and filed a minimum system study that allocated a portion of the distribution costs in Accounts 364-368 on the basis of number of customers, instead of allocating those costs based upon demand. . . . Although PSO performed the minimum-system study as required, PSO did not utilize

> the minimum-system study in its cost-of-service study and advocated the continued allocation of the distribution costs in Accounts 364-368 on a demand-only basis, as has been approved by the Commission for PSO since the 1980s . . . .
>
> PSO explained that it used a demand-only allocator for distribution costs in Accounts 364-368 because the distribution system poles, wires, and conduit contained in those accounts are sized to meet the maximum load demand imposed on the system and the cost of those facilities does not vary directly with the number of customers . . . .
>
> The Commission finds that PSO's demand-only methodology for classifying distribution system costs in Accounts 364-368 is reasonable and finds that PSO's retail cost-of-service study should be accepted.
>
> (Order No. 564437 dated January 14, 2009 (2009 WL 512577).)

Q. If a regulatory commission has not explicitly rejected the Minimum System approach, does this necessarily mean it has accepted the approach?

A. No. For example, we did not find any orders in which the Idaho Public Utilities Commission made a decision to either accept or reject the Minimum System approach. Nevertheless, upon further investigation, we found testimony filed by Avista Utilities in a recent case (IPUC Case No. AVU-G-15-01), which explains that the utility allocated distribution mains using the same methodology it used in numerous past cases. While the witness does not explicitly mention the Minimum System approach, his exhibit describing the cost of service study shows that distribution mains were allocated 100% on demand, using a combination of Average Peak demand (annual throughput) and Coincident Peak demand.

Q. To wrap up this discussion, can you briefly explain what conclusion you reached from your review of cases in other states?

A. While the City's witness is correct in noting that the Minimum System approach has been used by New York utilities and accepted in other cases, this does not mean the concept is universally accepted, nor does it provide a valid reason for relying on a Minimum System analysis to establish rates in these cases. The concept is fundamentally unsound, and we recommend that cost results based upon this methodology not be given any significant weight in these cases.

III. REVENUE ALLOCATION

Q. How did other witnesses deal with revenue allocation in their direct testimony?

A. Witnesses for the DPS Staff and the City proposed increasing the firm rates for various classes largely on an across-the-board basis, with somewhat different percentage increases applied to certain selected classes. Methodologically, the revenue allocation approach DPS Staff and the City used is similar to what the Companies proposed, with the exception of how they each handled certain classes.

The Staff Gas Rates Panel explained its recommendation as follows:

> Due to the magnitude of the rate increases, we recommend that all firm services classes receive the same percentage increase. At this time, we do not believe it is appropriate to move service class rates of return closer to the system average because of the projected bill impacts.

(Direct Testimony of Staff Gas Rates Panel, p. 43.)

Mr. Baudino, testifying on behalf of the City, expressed a similar concern, but he placed more emphasis on the results of KEDNY's ECOS study, with particular regard to the temperature controlled ("TC") and interruptible ("IT") classes. He agreed with the KEDNY's proposal to include these classes in the ECOS study and to begin basing their rates on the ECOS results, rather than continuing with market-based or value-based rates:

> The TC service classes and SC-18 are significantly overearning, which means that the rates these classes are currently paying are significantly greater than the cost based rates that they should be paying.
>
> . . . the Company's proposed class-specific increases/decreases are nowhere near what is needed to eliminate the interclass subsidies that the ECOSS reveals.
>
> Given the very large delivery service rate increase the Company seeks in this case, I appreciate that the Company is constrained in reallocating revenue responsibility so that the service classes that are below their cost to serve do not experience rate shock. However, customers paying 10-40 times their cost of service should not be increased. Therefore, I recommend that KEDNY's revenue allocation proposal be modified so that the TC classes do not receive any increases in current delivery revenues. I recommend that, as is proposed for SC-18-

> 5A, the TC classes should have rates designed so that the current level of revenues forecasted by KEDNY remain constant. I also recommend that the SC-4 classes receive no increase, given their excessive current revenue levels.
>
> (Direct Testimony of Richard Baudino, p. 10.)

Q. Have you compared the Companies' revenue allocation proposals to those of the DPS Staff and the City?

A. Yes. The Companies, the Staff Rates Panel, and Mr. Baudino all use very similar approaches to allocating the revenue increase to the various classes. They each select certain classes for special treatment, and then apply a uniform across-the-board percentage increase to all of the remaining classes. Not only are the Companies' and the City's general approaches similar, they tended to select the same classes for special treatment – primarily the TC and IT classes. While there are noticeable differences in the percentage increases included in their respective proposals, those differences can largely be traced to differences in how they handled the classes that were selected for special treatment.

Q. Putting aside for a moment classes that are selected for special treatment, what is your response to this modified across-the-board approach?

A. As we explained in our direct testimony, we see merit to some aspects of this approach. Of course, we also expressed some reservations – particularly with respect to the treatment of TC and IT customers, and with respect to which

ECOS results are relied upon in developing the revenue allocation. To be clear this modified across-the-board approach does not force a specific amount of movement toward the goal of eliminating the deficiencies or surpluses that are reflected in the ECOS results (nor does it use a traditional tolerance band around the system average). Instead, it focuses on achieving reasonable, consistent percentage increases for each class, while selecting some classes for special treatment, in recognition of the ECOS results, or for some other specific purpose. We see some benefits to this approach, compared to a more mechanical approach tied to tolerance bands, which can be particularly problematic when the Companies' underlying ECOS studies are flawed.

Especially given the large degree of convergence that exists amongst other witnesses supporting this methodology, we have no objection to using it in these cases to resolve the revenue allocation issue. However, we do have some concerns about which classes are selected for special treatment, and the manner in which these classes are handled.

Q. Have you developed alternative revenue allocation recommendations also using a modified across-the-board approach?

A. Yes. Our recommendations are illustrated on Page 5 of Schedule 1 of Exhibit __ (URP-4) and of Exhibit __ (URP-5). In each Exhibit our approach is the same, but the specific recommendations reflect differences in the ECOS results and existing rate levels between Companies. These differences translate into differences in the overall percentage rate increase or decrease for specific classes.

Q. Can you please briefly explain how and why your revenue allocation and rate recommendations differ from those of the other witnesses?

A. Yes. Page 1 of Schedule 1 of Exhibit __ (URP-4) provides a simplified side-by-side comparison for KEDLI, while page 1 of Schedule 1 of Exhibit __ (URP-5) provides the analogous side-by-side comparison for KEDNY. Additional details are provided on subsequent pages of each schedule.

The Exhibits illustrate the revenue allocation proposals of the City and the Companies using the revenue requirements and projected billing units proposed by the Companies, while the DPS Staff proposals are illustrated using the DPS Staff's recommended revenue requirements and projected billing units. We have also illustrated the UIU recommendations using DPS Staff's billing units and revenue requirements. To be clear, however, we have not studied DPS Staff's revenue requirement calculations in detail, and we do not here take a position concerning the appropriate revenue requirement or any of the issues which contribute to differences between DPS Staff's numbers and those of the Companies.

Under each recommendation, rates for most classes will increase by a uniform percentage that is similar to the overall percentage increase. The main exceptions are the interruptible and TC classes, which we discuss in the next section of our testimony. Another exception is KEDNY's SC-1A Residential Non-Heat class, which we recommend be increased by less than the overall average. The SC-1A class is generating a high rate of return under both of the ECOS studies we prepared, and customers are currently paying an effective rate of nearly $1.72 per therm (which helps explain why they are overearning according to our ECOS study), as shown on Page 1 of Schedule 3 of Exhibit __ (URP-2) accompanying our direct testimony. Moreover, giving this class a somewhat lower percentage increase reduces the impact on customers that would otherwise result from our recommendations concerning the customer charge and volumetric rates, as discussed later in our testimony.

IV. INTERRUPTIBLE AND TEMPERATURE CONTROLLED RATES

Q. What did the Staff Gas Rates Panel testify concerning the Companies' proposal to switch to cost-based pricing for non-firm service?

A. The Staff Gas Rates Panel acknowledged these rates are currently market-based and reflect value-of service pricing principles, but it did not say much about the Companies' proposal to include these non-firm rates in the ECOS studies, or to begin a transition toward cost-based pricing. Moreover, these classes are not shown in Staff's exhibit SGRP-9, so we are not certain precisely what they are intending to do about these classes. As we discussed in our direct testimony, since most ECOS methodologies rely heavily on peak usage data (and non-firm customer classes are often excluded from the peak allocation factors even if they were not interrupted during the peak), the allocation results will not necessarily be meaningful or reliable for non-firm classes. With very little investment allocated to these classes, extremely high rates of return can be computed, but the results are not necessarily meaningful or reliable – just as dividing by zero does not produce a meaningful number in math.

Q. Some of the other witnesses are suggesting that IT rates should be cost-based. Can you please briefly explain why you disagree?

A. Yes. Natural gas transmission and local distribution companies both benefit from pervasive economies of scale and scope. When many different types of customers receive energy through a single integrated system, enormous cost savings are achieved, due to economies of scale and scope that benefit all types of customers. Additional savings can be achieved when a system is designed to handle the peak volumes of only some customers (opting for firm service), while allowing other customers to “rent” available capacity on the system during off-peak times at a discounted price. This makes it feasible to handle a larger volume of gas at lower cost than if every customer received firm service.

A purely cost-based approach to pricing of interruptible service could lead to a highly inequitable result, in which the IT customers gain enormous benefit from using the system without bearing any significant share of its costs. The simplest solution to this problem is to continue to use value-of-service pricing principles to ensure that both IT and firm customers share in the benefits that are achieved by having IT customers on the system.

In contrast, a purely cost-based approach (particularly one that is tied to a peak demand-based cost allocation methodology) could give IT customers a virtually “free ride” on the system. This would be both deeply unfair and economically irrational. IT customers would be contributing little or nothing toward the fixed costs of the distribution system, yet they would gain nearly as much benefit from using the system as firm customers of equivalent size. The firm customers would bear the entire burden of paying the fixed costs of the system, while the non-firm customers would not bear any of that burden.

We would also note that we have included the TC and IT classes in Schedules 1 and 2 of Exhibit ___ (URP–4) and Exhibit ___ (URP–5) to provide more direct comparability with the Companies' proposals. As mentioned above, and explained in our direct testimony, we do not think the TC and IT customers belong in any of the ECOS studies, and we don't think the calculated rates of return for these classes are meaningful, nor do we think any weight should be given to the allocated cost results for these classes. Instead, rates for these classes should continue to be based upon value of service and market forces.

Q. What did the Staff Gas Rates Panel testify concerning how non-firm rates should be set?

A. The Staff Gas Rates Panel focused on the relationship between firm and non-firm rates. Among other things, it expressed concern that the Companies have not maintained a consistent discount from equivalent firm rates sufficient to compensate for the added costs incurred by non-firm customers in order to maintain dual fuel capability. The Staff Gas Rates Panel explained its concerns as follows:

> Due to issues with the oil industry's ability to provide reliable service during the polar vortex, historic alternative fuel prices, the City of New York's requirements that certain alternative fuels be phased out, the Companies practice of pricing non-firm service up to firm rates have resulted in non-firm customers converting to firm service.
>
> (Direct Testimony of Staff Gas Rates Panel, p. 34.)

In response to this situation, the Panel recommended that non-firm rates be capped at a level that is below the otherwise applicable fully bundled firm service:

> IT rates should be set at a point between rates that are low enough to make it economically beneficial for customers to choose IT service over firm service, and rates that are high enough to ensure that firm customers are maximizing the financial benefit that IT customers provide.
>
> (Direct Testimony of Staff Gas Rates Panel, p. 35.)

Q. What is your response?

A. Because the non-firm rates have been market-based, rather than directly regulated by the Commission, and because in recent years the cost of alternative fuels has been high relative to the price of natural gas, the Companies have not needed to keep non-firm delivery rates below the level of firm delivery rates. However, if this situation continues, it will eventually encourage non-firm customers to convert to firm service (to the extent they are able to do so). While an optimal long-term pricing strategy for non-firm service would not necessarily avert any and all movement from non-firm to firm service, neither would such a strategy entirely eliminate the long-term economic viability of non-firm service. If non-firm service is priced above the firm rate for extended periods of time, customers will be discouraged from using non-firm service, and the potential economic benefits of interruptible service will ultimately be lost. In other words, even if market conditions temporarily allow non-firm rates to be priced higher than firm rates, this would not be an optimal long-term pricing policy because it would eventually lead to most customers abandoning non-firm service, which would reduce system utilization and drive up unit costs. Instead, a balance should be struck between non-firm and firm rates to achieve an equitable and efficient overall result. In essence, the goal is to provide an economic incentive for at least some customers to choose non-firm service, while also ensuring that those customers do not get a nearly "free ride" and ensuring that the firm customers also benefit from the decision of other customers to opt for non-firm service.

Q. Did the Staff Gas Rates Panel offer more specific recommendations concerning the size of the discount that should be offered for non-firm service?

A. Yes. The Panel proposed setting TC prices 20% below the analogous firm rate, and setting IT prices 30% below the analogous firm rate. The Panel explain its reasoning as follows:

> It is not possible to calculate the exact costs non-firm customers incur to take non-firm service. It is, therefore, difficult to determine the exact discount that should be established off of firm service. That being said, we recommend a 20 percent discount off of the applicable firm rate for TC customers and a 30 percent discount for IT customers.
>
> Establishing the cap allows the Companies the ability to match the rates it charges to non-firm customers with the value that the competitive market conditions allow. However, setting the cap without a discount, or up to the firm rate, as was done historically, does not guarantee non-firm customers a discount compared to rates for firm service, nor does it recognize the benefits they provide the gas system.
>
> (Direct Testimony of Staff Gas Rates Panel, p. 35.)

Q. Do you agree with this proposal?

A. We see some merit to this general approach, but we are not convinced these are the correct percentage discounts to offer at this time.

We see merit to moving toward a more transparent and consistent policy, in which the Commission examines the relationship between firm and non-firm rates to ensure that both firm and non-firm customers benefit. We also agree with the idea of using the analogous firm rates as a benchmark; this can be a useful tool in achieving greater consistency and transparency. We also agree that an optimal long-term non-firm pricing strategy should provide a reasonable discount for non-firm service, relative to the benchmark firm rate. However, we are not convinced that a discount as large as 20% to 30% is necessary or appropriate under current market conditions, particularly in cases where a smaller discount has been accepted or negotiated by the non-firm customers, and the non-firm rate is still lower than the cost of alternative fuels.

We also disagree with DPS Staff's argument that IT service should be given a deeper 30% discount than the 20% discount that it proposes for TC service, in order to persuade customers to switch from TC to IT service. For one thing, the Staff hasn't offered a convincing argument for moving customers of TC service. To the extent the current TC tariffs are flawed, it would be preferable to implement narrowly targeted solutions to specific problems, rather than pushing customers off the service. Furthermore, from a rate design perspective, it seems illogical to give a deeper discount to IT customers, since the TC customers are actually interrupted more frequently, and are sometimes required to remain without gas for longer periods than IT customers. Given the resulting difference in the value of TC and IT service, from a rate design perspective, it would seem more logical to offer a lower discount to IT customers, rather than vice versa. Finally, we would point out that other differences can exist including differences in TC and IT customer load characteristics and ability to bypass, which should be considered before concluding how large a discount is optimal for the two categories.

We are also concerned about the need to maintain a reasonable degree of rate continuity. If the Commission decides to move toward a policy in which non-firm rates are offered a specific percentage discount off the firm rate, movement to this approach should probably be phased in over a period of years, both to avoid rate shock (if the non-firm rates currently provide a much larger discount) and to provide fairness for firm customers (if the non-firm rates currently have a much lower discount than is proposed).

Finally, the Staff has not offered a persuasive argument to support its proposal to retain the imputation and 90/10 sharing mechanisms. Both of those mechanisms seem to be logically linked to the assumption that negotiated, market-based pricing will be used for non-firm service. If rates are not constrained by market forces, but instead are going to be determined by their relationship to firm rates, then why does the Company need to receive a 10% share as an incentive?

Given current market conditions, there is little risk of customers switching from natural gas to an alternative fuel, so there does not seem to be much need to provide the Companies with the flexibility to negotiate different prices for individual customers. Only in the context of individual customer negotiations does the 90/10 sharing mechanism seem to offer much benefit, since it provides the Companies with a stronger incentive to negotiate aggressively for the benefit of the firm customers. In sum, we are not convinced these mechanisms are needed, particularly if the Commission moves away from individually-negotiated prices toward a policy of uniform discounts off the comparable firm rate.

Q. You indicated that you are not convinced a 20% to 30% discount is necessary under current market conditions. How do these proposed discounts compare to the existing rates?

A. Assuming we have correctly interpreted the data provided by DPS Staff in its workpapers, most of the non-firm customers appear to be receiving a smaller discount, while a few seem to be receiving a much larger discount. The far right column in Schedule 2 of Exhibit __ (URP-4) shows the relationship between the comparable firm rate and the current non-firm rate, as developed by DPS Staff in its workpapers. Schedule 2 of Exhibit __ (URP-5) provides the analogous comparison for KEDNY. If we have interpreted the data in DPS Staff's workpapers correctly, the IT customers in KEDNY's On System Large Volume Sales category (SC-18-5A) are the only non-firm customers receive a discount of 30% or more (and they appear to be getting a discount of approximately 80% off the firm rate). Other customers are currently receiving smaller discounts. The group that currently comes the closest to DPS Staff's proposed 30% discount level is KEDLI's SC-4 IT class, which is apparently paying 72.3% of the analogous firm rate, for an effective discount of about 28%. Another group that seems to be getting a similar discount to what DPS Staff proposes is KEDNY's SC-6C class, which is apparently paying 78.9% of the analogous firm rate, for an effective discount of about 21% – close to the 20% discount proposed by DPS Staff for TC customers. However, other classes appear to be currently receiving much smaller discounts than DPS Staff proposes.

If we have understood DPS Staff's workpapers correctly, it would appear that the proposed 20% and 30% discount rates would deviate significantly from existing rate relationships in at least some cases.

Q. Do you have any response to the testimony of other witnesses concerning the TC and IT rates?

A. Yes. We sympathize with many of the concerns expressed by Mr. John Dowling on behalf of Consumer Power Advocates ("CPA") and Ms. Barbara Tillman on behalf of Spring Creek Towers, particularly with regard to situations where the non-firm rates currently exceed, or are nearly equal to, the corresponding firm rate. As we mentioned above, we do not think it makes sense to switch to cost-based rates for non-firm rate classes, and it is not necessarily surprising that some market-based rates are close to firm rates, given the current state of energy markets, since natural gas prices are very low compared to alternative fuels.

While we think the Commission should take steps to ensure that a reasonable relationship is maintained between firm and non-firm rates over the long term, there is no need to implement a drastic realignment away from the existing market-based prices in this proceeding. Nor do we think a reasonable discount would necessarily be as large as DPS Staff suggests (20-30%). Yet, Mr. Dowling on behalf of CPA appears to propose an even more drastic realignment of rates in his testimony:

> In the absence of any relevant cost studies prepared by KEDNY, I recommend that all interruptible rates be limited to the delivery component of SC4 (A) High Load Factor Firm service. SC4 (A) is the lowest firm rate that reflects the value that high load factor customers provide to the system. Interruptible customers also add value by improving the system load factor, and thus it is appropriate to limit interruptible rates to the SC4 (A) rates, regardless that the otherwise applicable firm rate may be higher.
>
> (Direct Testimony of John Dowling, p. 11.)

As shown on Schedule 3 of Exhibit ___ (URP-2) accompanying our direct testimony (the same information is reported in Schedule 2 of Exhibit ___ (URP-5) for convenience), the SC-4A rate is very low compared to the rates charged most other customer classes. If Mr. Dowling's proposal were accepted, the TC customers could see their rates reduced by as much as 50%, as indicated by a comparison of the effective rates paid by SC-4 customers (around $0.16 per therm) and the effective rates paid by SC-6 customers (around $0.35 per therm) as shown on Schedule 2 of URP-5. We do not see any merit to using the SC-4A rate as a benchmark in this context, and we certainly do not see any merit to lowering the temperature-controlled rates at a time when firm customers will be asked to pay higher rates. If the Commission moves away from market-based pricing for non-firm service, we recommend instead using the closest analogous firm rate as the benchmark, and phasing in the change.

V. RATE DESIGN

Q. Can you briefly respond to the testimony of DPS Staff with respect to the rate design applicable to Residential and Small Commercial Customers?

A. Yes. We were pleased to see that the Staff Gas Rates Panel agreed with the Companies' proposals to maintain most of their customer charges at the current level. We view this as a significant movement in the right direction.

However, we would have preferred seeing more of an effort to avoid increasing the customer charges in the SC-1A non-heating classes. As we explained in our direct testimony, the existing customer charge for these classes exceeds their customer costs. As our illustrative rates demonstrate, it is feasible to maintain this rate element at the existing level, assuming a more reasonable share of the revenue requirement is allocated to the Companies' SC-1A non-heating classes.

Q. Have you developed exhibits that can help clarify your rate design recommendations as compared to the rates proposed by Companies and DPS Staff?

A. Yes. Schedule 3 of Exhibit ___ (URP-4) illustrates our rate design recommendations for KEDLI, under the assumption that DPS Staff's revenue requirements will be adopted by the Commission. Schedule 3 of Exhibit ___ (URP-5) illustrates our rate design recommendations for KEDNY, under similar assumptions. Our recommended rates can therefore be compared directly to the rates proposed by the Staff Gas Rates Panel.

Our rate design recommendations are illustrated in the far right column of each page. Our illustrative delivery rates can be compared to the Companies' existing and proposed delivery rates (shown in the first and second columns) and the delivery rates developed by the DPS Staff witnesses (shown in the third column). For convenience, we also show the extent to which each illustrative rate element reflects an increase relative to the current approved tariff, stated in percentage terms.

Q. Have you developed exhibits that illustrate the impact of your recommended rate design on typical customer bills?

A. Yes. Schedules 4 – 6 of Exhibit ___ (URP-4), and Schedules 4 – 6 of Exhibit ___ (URP-5), illustrate the impact of our rate design recommendations on typical bills for residential and small commercial customers on KEDLI's system, and KEDNY's system, respectively. We present bill impacts that are specifically focused on the portion of the delivery charges that we discussed in our direct testimony. This provides a better representation of the true impact of the different rate designs presented by the Company, DPS Staff, and UIU. These comparisons include the majority of the delivery portion of the bill, and exclude portions of the bill that recover commodity costs, gross receipt taxes, and some other miscellaneous items that are not the primary focus of our testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.