IEc

BEFORE THE RÉGIE DE L'ÉNERGIE

IN THE MATTER OF:

Société en commandite Gaz Métro (Gaz Métro)

Demande relative au dossier générique portant sur l'allocation des coûts et la structure tarifaire de Gaz Métro

prepared on behalf of:

l'Association des Consommateurs Industriels de Gaz (ACIG)

DOSSIER R-3867-2013

prepared evidence of:

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1. INTRODUCTION

PLEASE STATE YOUR NAME AND BRIEFLY DESCRIBE YOUR BACKGROUND.

My name is Robert D. Knecht. I am a Principal of Industrial Economics Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I prepare analyses and expert evidence in the field of regulatory economics. In Canada, I have submitted expert evidence in regulatory proceedings in Québec, Ontario, Alberta, New Brunswick, Nova Scotia, Manitoba, and Prince Edward Island. In Québec, I have submitted evidence in proceedings involving Hydro Québec TransÉnergie, Hydro Québec Distribution, and Gaz Métro, in matters involving utility revenue requirements, cost allocation, cross-subsidization, rate design, and industry restructuring. My résumé and a listing of proceedings in which I have submitted expert testimony in the past five years is attached as Exhibit IEc-1.

WHAT IS THE PURPOSE OF THIS TESTIMONY?

As stated in its filing, Société en commandite Gaz Métro ("Gaz Métro" or "the Company") retained an external consultant and evaluated all aspects of its existing cost allocation methodology, pursuant to various decisions by the Régie.[1] In this proceeding, the Company proposes to make a variety of changes to that methodology. I have been asked by l'Association des Consommateurs Industriels de Gaz ("ACIG") to review the Company's proposals for its cost allocation methodology and evaluate whether they are reasonably consistent with sound economic and regulatory principles.

DO YOU HAVE ANY CAVEATS REGARDING THIS EVIDENCE?

I do. While the technical sessions in this proceeding provided some useful general information, it is difficult to assess the details of a cost allocation methodology without reviewing the actual data and calculations that go into the study. Summary descriptions of cost allocation methodologies can easily be mis-interpreted, unless accompanied by the specific data, equations and calculations. Much of the detailed discovery involving specific aspects of the calculations were not provided during the technical sessions, and were deferred to the interrogatory phase of this proceeding. Due to a relatively short time available between the responses to discovery and the filing date for this evidence (as exacerbated by my need for translation), my analysis is preliminary. While I have conducted certain analyses of the interrogatory responses, my analysis is ongoing. I will continue to analyze the evidence on the record and apprise parties of any changes in my findings at the earliest opportunity. Moreover, to the extent that I do not explicitly comment on a particular allocation method cannot be construed to imply that I agree with the Company's proposal.

WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARING THIS EVIDENCE?

The documents that I reviewed are listed in Exhibit IEc-2. In this evidence, I address a relatively wide array of cost allocation issues. In so doing, I relied on my experience and

[1] Gaz Métro retained the services of Dr. H. Edwin Overcast of Black & Veatch ("B&V") Company.

the documents listed in Exhibit IEc-2. Time and budget constraints precluded a detailed review of all Régie decisions relating to cost allocation issues over the years.

WHAT IS THE PURPOSE OF A COST ALLOCATION STUDY?

Of the established criteria for setting rates for regulated utilities, the principle of aligning rates with cost of service is generally the most important.[2,3] Utilities generally group customers into relatively homogeneous “rate classes,” and a cost allocation study assigns costs to each class. The cost allocation study therefore serves as a cost basis for the revenues to be recovered from each class. In addition, the cost allocation study often provides useful information for setting rates that apply to each rate class.

AT SECTION 3.2 OF GAZ MÉTRO - 1, DOCUMENT 2 (EXHIBIT C-ACIG-0008), THE COMPANY LAYS OUT A SET OF GUIDING ECONOMIC PRINCIPLES FOR COST ALLOCATION. DO YOU AGREE WITH THOSE PRINCIPLES?

I have no theoretical disagreement with the principles laid out in that document. However, let me highlight three practical implications of those principles for the Company’s filed cost allocation proposal in this proceeding.

First, it is long-established that “subsidy-free” pricing involves setting prices that exceed the incremental cost and fall below the stand-alone cost of providing service to a customer or group of customers.[4] However, from a practical perspective, these criteria do not provide a significant constraint to cost allocation for gas distribution utilities. As Dr. Overcast explains, there are significant economies of scale in gas distribution, such that the incremental cost of serving an additional customer or group of customers is typically much less than the standalone cost of providing service to that customer. As such, these basic economic constraints can encompass a large number of alternative cost allocation schemes.

Nevertheless, the standalone cost test can come into play for gas distribution cost allocation and rate design, particularly for large industrial customers. In some cases, large industrial customers are located in reasonably close proximity to gas transmission lines and require only a minimum of investment by the gas distributor. In those cases, the standalone cost of serving a large industrial customer can be less than the costs assigned to that customer using arbitrary cost allocation methods, resulting in an implicit violation of the standalone cost criterion.

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[2] For commonly cited rate design criteria, see Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, and Kamerschen, 1988, pages 383-384.

[3] For example, the Pennsylvania Commonwealth Court described cost of service as the “polestar” criterion for utility rates. Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[4] See, for example, See, for example, Transmission Pricing and Stranded Costs in the Electric Power Industry, Baumol, William J. and J. Gregory Sidak, The AEI Press, 1995, chapters 6 and 7.

In the U.S., this issue is often implicitly regulated through the threat of bypass, since large industrial customers are legally permitted to interconnect directly with the interstate pipelines. In those cases, gas distribution utilities adopt a variety of approaches, both in cost allocation and rate design, to ensure that large industrial customers do not pay more in rates than the standalone cost of service.

In Gaz Métro's case, it is my understanding that customers are not permitted to bypass the distributor and interconnect directly with the transmission system. Because the bypass threat does not exist, it becomes incumbent upon the regulator to enforce the standalone cost criterion for such customers. I therefore recommend that the Régie adopt a specific criterion that allocated costs not exceed the standalone costs for any customers.[5]

Second, Gaz Métro cites a "decomposition principle" as having merit, meaning that customers should not be required to contribute to portions of the system that they do not use. This is, of course, a logical, common-sense principle. However, gas distribution systems are designed to operate at different levels of pressure, ranging from the highest pressure lines attached to the transmission system, to the lower pressure lines serving the smallest customers.[6] The decomposition principle implies that customers who take service at parts of the system that operate at higher pressure be allocated costs only related to the higher pressure systems. Customers who take service at lower pressures would generally be allocated costs for both higher pressure and lower pressure systems, as they use both systems.

In this proceeding, however, Gaz Métro proposes to directionally move away from this principle, by aggregating its distribution and supply (alimentation) mains into a single cost pool, and allocating those costs among all customers, regardless of the operating pressure at which they take service.

Third, consistent with the decomposition principle, there is the general agreement among cost allocation analysts that it is preferable to directly assign costs than to allocate costs. Thus, when costs can be directly associated with a specific customer or customer class, those costs should be assigned to that customer or class. This policy is not explicitly included in the Company's discussion, but I recommend that the Régie include it in its general principles.

WHAT COSTS ARE ALLOCATED IN A COST ALLOCATION STUDY?

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[5] Gaz Métro includes this principle in its discussion, at Exhibit C-ACIG-0008, page 12, item 5 and page 13, item 2 (first occurrence).

[6] Gaz Métro has three generic categories of operating pressure, including transmission (4,400 to 9,928 kPa), supply or alimentation (1,000 to 2,900 kPa) and distribution (0 to 700 kPa). A significant majority of distribution mains operate at 400 kPa. See Exhibit C-ACIG-008 page 23 and B-0062.

Cost allocation studies come in two generic varieties: fully distributed cost (also known as "embedded" cost) allocation methods and marginal/incremental cost allocation studies. In a fully distributed cost allocation study, each component of a utility's test year revenue requirement is allocated amongst the various rate classes. In marginal cost allocation studies, the costs associated with an incremental unit of consumption are derived for each rate class. While marginal cost allocation studies have more theoretical appeal, the use of fully distributed cost methods is widespread for a variety of reasons. Relative to a marginal cost allocation analysis, fully distributed cost methods generally produce more stable results from rate case to rate case. In addition, fully distributed cost methods do not require a "true-up" mechanism that is necessary in marginal cost allocation studies, to reconcile the allocated marginal costs with the utility revenue requirement. Thus, many regulators and natural gas distribution companies ("NGDCs") rely on fully distributed cost methods.

In this proceeding, Gaz Métro proposes to continue to use a fully distributed cost method. I take no exception to this proposal.

WHAT ARE THE BASIC COMPONENTS OF A FULLY DISTRIBUTED COST ALLOCATION STUDY?

A fully distributed cost study traditionally consists of three general steps: functionalization, classification, and allocation.

The functionalization step splits costs among the various functions performed by the utility. For traditional integrated natural gas utilities, these functions generally include gas supply, transportation, load balancing, distribution and customer service. For the most part, costs are functionalized within the utility's accounting system, although certain overhead costs often need to be distributed among the various functions. However, as this is a distribution cost allocation proceeding, the vast majority of costs in question are distribution and customer service costs. However, some utilities "sub-functionalize" their mains costs at a more detailed level, such that costs are segregated by operating pressure or other characteristics. For example, Gaz Métro's current cost allocation study separately tracks distribution, supply and transmission mains.

The classification step splits the functionalized costs into groups based on cost causation factors. Costs which vary with the amount of gas delivered over an extended period of time are classified as "energy-related" or "commodity-related."[7] Costs which vary with peak usage levels are classified as "demand-related," and costs which vary with the number of customers are classified as "customer-related." Costs which vary with the

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[7] Note that "energy," "commodity," and "average demand" are generally arithmetically equivalent concepts for cost allocation, in that they all vary with periodic consumption.

difference between peak demand and average demand, such as gas load balancing costs, are classified as “excess” related.

The allocation step then distributes the classified costs to each customer class based on an allocation factor that reflects each class’ contribution to the cost causation factor. Energy-related costs are generally allocated using a measure of annual or seasonal consumption, demand related costs are allocated using some measure of class peak demand, customer costs are allocated using unweighted or weighted customer allocators, and excess demand costs are allocated using a measure of the difference between peak and average demands.

2. DISTRIBUTION MAINS CLASSIFICATION AND ALLOCATION

AT EXHIBIT B-0023 PAGE 6, THE COMPANY INDICATES THAT CLASSIFYING AND ALLOCATING MAINS COSTS IS THE MOST COMPLEX AND MOST CONTENTIOUS ASPECT OF NGDC COST ALLOCATION. DO YOU AGREE?

I do.

In traditional NGDC cost allocation studies, the primary debate applies to the issue of “classifying” mains costs into demand-related, customer-related and (sometimes) energy-related components. This debate arises for two basic reasons.

The first is that there is no obvious theoretically correct answer to the question. From an engineering perspective, each length of main must be sized to meet the maximum demand of all firm service customers downstream from that main (without an undue loss of pressure), and the total mains system must be extended to interconnect all customers. This leads to a common sense conclusion that mains costs are causally related to both design demand (size of pipe) and number of customers (length of pipe). However, mains costs are also affected by a variety of factors, including differences between urban and rural construction, soil conditions, road conditions, rights-of-way, etc., and it is unclear whether or how such factors can or should be reflected in a cost allocation study. Moreover, as Dr. Overcast correctly demonstrates, mains costs exhibit substantial economies of scale, and it is a matter of some debate about how those economies should be reflected in mains cost allocation.[8]

The second reason for the debate is that the choice of methodology has a large impact on the end result, as a result of three factors:

- Mains plant usually represents a large share of a utility’s rate base, and therefore accounts for a large share of the costs directly related to rate base, namely

[8] Exhibit B-0005, pages 10-11.

depreciation, return and income taxes. In Gaz Métro's case, mains plant represents over half of the Company's rate base.[9]

- Due to the nature of utility cost allocation studies, other costs are indirectly influenced by the allocation of mains costs, namely operating and maintenance ("O&M") costs related to mains, as well as general plant costs.
- The allocation factors are very different depending on whether mains costs are classified as demand-related or customer-related. Table IEc-1 below shows the difference in design demand and customer allocation factors for the aggregated Gaz Métro rate classes.

TABLE IEc-1
COMPARISON OF BASIC GAZ MÉTRO ALLOCATORS

Rate Class	Customer Percent	Energy Percent	Demand Percent
D1 < 36,500 m^3	93.94%	14.32%	15.26%
D1 > 36,500 m^3	5.17%	19.89%	22.08%
D1-RT	0.65%	9.17%	7.47%
D3	0.12%	3.20%	0.78%
D4	0.05%	41.36%	41.07%
D5	0.07%	12.06%	13.33%
Total	100.00%	100.00%	100.00%

Source: Exhibit B-0040; Factors FB08, FB01D, CA

WHAT IS THE COMPANY'S CURRENT METHOD FOR CLASSIFYING AND ALLOCATING DISTRIBUTION MAINS COSTS?

As I understand it, the current process is as follows:

- Mains costs are sub-functionalized into transmission, supply (alimentation) and distribution categories, based on operating pressure.
- Transmission and supply mains are classified as 100 percent demand-related and allocated using a hybrid design demand/commodity allocation factor (the "CAU" allocator).

[9] Illustrative costs and allocation factors in this evidence are based on Exhibit B-0040, the Company's proposed cost allocation study applied to the 2013/2014 budget year, unless otherwise specified.

- Distribution mains are segregated by region, classified using a regional zero-intercept methodology and aggregated to a weighted average system classification factor. According to Exhibit B-0039, the current methodology produces an average cost classification split of 29 percent demand-related, 71 percent customer-related for distribution plant.
- The classified mains costs are allocated by applying the CAU factor to demand-related costs and a customer count allocator to customer-related costs.

WHAT CHANGES DOES GAZ MÉTRO PROPOSE IN THIS PROCEEDING?

The following changes are proposed:

- Gaz Métro indicates that it has carefully reviewed its mains cost data and eliminated errors and outliers from the data sets used for cost allocation.
- Distribution and supply mains would be aggregated and allocated together.
- The regional aspect of the current classification method would be replaced with a "global" classification approach.
- Distribution/supply mains would be classified using a minimum system method, in which the minimum system is defined by the inflation-adjusted cost of a 60.6 mm (2-inch) plastic main.
- The inflation factor used to deflate historical mains costs would be modified from the current Québec consumer price index ("IPC") to the use of "Handy-Whitman" utility construction cost indices for the northeast United States.
- Demand-related costs would be allocated using a design demand allocation factor, except that no demand-related costs would be assigned to Rate D1 customers with annual consumption below 36,500 m^3.
- Design demand for interruptible customers would be included in the allocation factors for distribution and supply mains demand-related costs.
- Customer-related costs would be allocated based on number of service lines rather than customer count.

GAZ MÉTRO INDICATES THAT THE ZERO-INTERCEPT METHOD PROVIDES A THEORETICALLY MORE CORRECT ALLOCATION OF COSTS.[10] PLEASE COMMENT.

The zero-intercept method is one of the generally accepted methods for mains classification and is used by various utilities and regulators. However, from a strict theoretical standpoint, the zero-intercept method is at best a rough approximation to cost causation. The zero-intercept method relies on the assumption that the customer-related

[10] See, for example, Exhibit B-0023 page 22, Exhibit ACIG-C-0008 page 29.

portion of mains cost is equivalent to the cost of a replacing the existing distribution system with a theoretical system based on pipe with zero load-carrying capability.

However, this approach is not theoretically perfect. As I demonstrate algebraically in Exhibit IEc-3, the customer component as defined in zero-intercept method implicitly includes a demand-related component, and the demand component of costs implicitly includes a customer-related component. While these effects tend to directionally offset, there is no guarantee that the zero-intercept method produces an unbiased classification factor.

IS THE ZERO-INTERCEPT METHOD SUPERIOR TO THE MINIMUM SYSTEM METHOD?

In my view, the zero-intercept method is theoretically superior, although imperfect for the reasons discussed above.

The minimum system method has the same theoretical flaws as the zero-intercept method, but it has additional theoretical problems. The most common complaint against the minimum system method is that the minimum system itself has some load carrying capability. Thus, the minimum system method is often criticized as overstating the customer component of costs.

However, as the Company's evidence indicates, the minimum system approach is generally perceived as having the advantages of simplicity and stability. The zero-intercept method relies on a statistical estimation of the relationship between mains cost and mains size. This analysis requires analytical judgment regarding model specification, the data to be included in the analysis, and the data weighting methods that should be applied. This judgment leads to more uncertainty and more debate, complicating the process.

IN THE SPECIFIC CASE OF GAZ MÉTRO, DO THE REGIONAL ZERO-INTERCEPT REGRESSIONS PRODUCE UNREASONABLE RESULTS WHEN APPLIED TO THE COMPANY'S UPDATED MAINS DATA?

In its evidence, the Company cites statistical problems with the regression analyses that support the current methodology. At the global level, the Compay's concerns relate to statistical equations estimated using combined steel and plastic main datasets.[11] In my experience, zero-intercept analysis is usually conducted separately for steel mains and plastic mains, and the customer component of costs is derived as a weighted average of the two results. Based on my statistical analysis of the global datasets, I did not observe statistical problems when the regressions were separately estimated.

Nevertheless, when applied at a regional level, the regression analyses produce counter-intuitive results in a number of cases, notably for the steel regressions, but also for at least

[11] Exhibit C-ACIG-0008, page 34 (regional), Exhibit B-0023 page 30 (global).

one plastic mains regression. For example, a number of regressions produce negative intercept values, and some regression produce cost estimates implying that costs decline with pipe diameter.[12] Whether these statistical problems are related to the data issues discussed below, or whether they result from cost causation factors other than those modeled cannot be determined at this time. However, based on the available data, it appears that application of the zero-intercept model to individual regions is not producing reasonable results in several cases.

Thus, based on the information available at this time, if the zero-intercept method is retained, I recommend that it be calculated at the global level, and that the customer component represent a weighted average of the zero-intercept main cost from separately estimated steel and plastic main cost regressions.

DOES THE COMPANY PROPOSE TO MODIFY THE MINIMUM SYSTEM METHOD TO TRY TO ADJUST FOR THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM?

Yes. As noted above, Dr. Overcast proposes that no demand-related costs be assigned to Rate D1 customers with annual loads below 36,500 m^3.

DOES DR. OVERCAST'S ADJUSTMENT TO THE DEMAND ALLOCATION FACTOR RESOLVE THE THEORETICAL PROBLEMS WITH THE MINIMUM SYSTEM METHOD?

Directionally, Dr. Overcast's adjustment reduces the problems associated with the minimum system method. However, the proposed adjustment raises methodological concerns.

First, if Gaz Métro's entire distribution system were replaced with 2-inch plastic pipe, that system would presumably not have the capacity to serve all Rate D1 customers with less than 36,500 m^3 of annual load. Where 6-inch or 8-inch steel supply mains serve thousands of small customers, a single 2-inch plastic main would not have sufficient capacity to meet the needs of the downstream customers. From this perspective, Dr. Overcast's adjustment will tend to serve to understate the costs of serving smaller customers.

Second, even if Dr. Overcast's adjustment accurately reflected the load carrying capability of the minimum system, he proposes to apply it only to Rate D1 customers with less than 36,500 m3 of annual load. However, the minimum system serving all of the other rate classes should also meet some of those customers' demand requirements. Thus, under Dr. Overcast's rationale, all demand allocation factors should be adjusted for

[12] Exhibit B-0045, item 10.

the load carrying capability of the minimum system, since all customers could be partially served by the minimum system.[13]

IS THERE A COST ALLOCATION APPROACH THAT IS THEORETICALLY SUPERIOR TO THE MINIMUM SYSTEM AND ZERO-INTERCEPT METHODS?

I am not aware of a simple, practical, widely used approach that is superior to these established methods.

Ideally, mains costs would be allocated only to customers who use the mains. The only way to accomplish that objective in a way that reflects the specific configuration of a particular gas system would be to evaluate the distribution system at a very detailed level. It is simply not possible for a minimum system or zero intercept method to correctly assess whether mains footage is being driven primarily by the need to serve distributed residential customers, or it is being driven by the need to serve remote industrial customers.

In such an ideal detailed method, the cost for each segment of pipe would be allocated to customers downstream of that pipe segment, based on each customer's design demand served by that pipe segment. This type of approach would have the advantages that mains costs would be assigned only to customers who use the mains, the demand-related component of cost would be directly reflected in the allocation of each pipe segment, and the customer-related component of cost would be directly reflected in that the costs for many kilometres of small-diameter mains would only be assigned to the small customers served by those mains, while the larger customers who required extended mains would be allocated the appropriate costs. As such, this approach would be fully consistent with the "decomposition" principle identified by Gaz Métro.[14]

The obvious disadvantages to such an approach are the complexity and the detailed data requirements.[15] Such an approach could only be undertaken if (a) the Company has the necessary data and information systems, and (b) the Company sees value in undertaking such an approach. At present, it is my understanding that the Company does not have the requisite information to undertake such a detailed evaluation.[16] As the geographic

[13] Directionally, attempting to correct this bias in the adjustment would serve to benefit medium-sized customers, by reducing demand-related costs assigned to them, and increasing costs to the assigned to the smallest and largest customers. Unfortunately, there is no obviously correct method for making such an adjustment to all rate classes.

[14] Exhibit C-ACIG-0008, page 13.

[15] For example, even if the system mapping information was available to link each mains segment with downstream load, the analysis would need to be adjusted to exclude mains extensions paid-for by downstream customers through customer contributions.

[16] See, for example, Exhibit B-0058, item 33(b).

information software and system modeling tools improve, I would expect that such an approach would become increasingly possible.

HAVE YOU ENCOUNTERED EXAMPLES OF THIS TYPE OF APPROACH?

A few, but not many. For example, at Pennsylvania Public Utility Commission Docket No. Docket R-00953297, UGI Utilities, Inc. (Gas Division) put forward a Network Analysis cost allocation approach, in which costs for each main segment were allocated to downstream customers in proportion to customer design day demands. Second, Alberta electric utility Aquila Networks Canada put forward a distribution cost allocation proposal in which allocated costs were derived at a detailed level for a sample of electric distribution feeders, in which distribution costs were allocated only to the specific customers downstream of each asset in proportion to on-peak load.[17]

ARE UTILITIES ADOPTING METHODS THAT ARE DIRECTIONALLY CONSISTENT WITH THIS APPROACH?

Some utilities have adopted conceptually similar approaches for larger customers. For example, National Fuel Gas Distribution's Pennsylvania Division identifies the specific facilities used to serve large industrial customers in Rate LIS, and directly assigns those costs to that class, thereby avoiding arbitrary allocation methods for that class.[18]

In addition, in their recent base rates proceeding, the FirstEnergy electric distribution companies in Pennsylvania (Metropolitan Edison, Pennsylvania Electric, Penn Power and West Penn Power) identified the specific primary voltage system equipment used to serve customers who take service at primary distribution voltage, and assigned those costs directly to the primary voltage service classes. The balance of distribution service plant, including both the rest of the primary system and secondary system assets, were assigned to customers taking service at secondary voltage.

IS THE COMPANY'S PROPOSAL TO AGGREGATE SUPPLY AND DISTRIBUTION MAINS REASONABLE?

The answer to this question depends on the paradigm chosen by the utility for cost allocation. If the data permit the utility to segregate costs and customers by operating pressure, then a more detailed approach can be taken, and there is no need to further aggregate system costs. Larger customers who take service at higher operating pressure do not use the lower pressure systems, and should not be allocated costs associated with low pressure systems. This approach is common for cost allocation in electric distribution systems, where primary voltage system costs are allocated to both primary voltage and secondary voltage customers, and secondary system costs are allocated only to secondary voltage customers.

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[17] See Alberta Energy and Utilities Board (now Alberta Utilities Commission) Decision 2003-019.

[18] Pennsylvania Public Utility Commission Docket No. R-00061493.

However, to the extent that the Company is unable or unwilling to pursue a more disaggregate, detailed assignment of costs, it is logical to take the combined approach. The Company indicates that it manages its supply and distribution systems as an integrated whole.[19] As such, the Company's proposed approach to aggregate the systems is generally consistent with its overall philosophy for mains cost allocation, once it concludes that it does not have sufficient system detail for a more in-depth assessment.

ARE OTHER NGDCS SEGREGATING MAINS COSTS INTO NARROWER COST POOLS?

In my recent experience, there is anecdotal evidence that some utilities are moving in the direction of more detailed sub-functionalization of costs and more close matching of costs with system usage.

First, in its most recent base rates proceeding, Columbia Gas of Pennsylvania sub-functionalized its gas distribution mains system into transmission, regulated pressure and low pressure systems, and then allocated costs only to those customers who used each of those systems. Costs for transmission mains and regulated pressure mains serving all customers were allocated to all customers. Costs for regulated pressure mains that served only customers who took service at regulated pressure were allocated only to those customers. Costs for low pressure mains were assigned only to customers taking service at low pressure. Where it was applied, classification of mains between customer and demand categories was based on a minimum system method for both low pressure and regulated pressure mains.[20]

Second, in its most recent base rates proceeding, Peoples TWP Gas followed a similar procedure, and segregated its distribution system into transmission, regulated pressure and low pressure systems.[21] Transmission and regulated pressure costs were allocated to all customer classes, while low pressure system costs were allocated only to customers who took service at low pressure.

Third, in its most recent case, Enbridge Gas New Brunswick segregated its mains costs between steel pipes and plastic pipes. Steel pipes were classified as 100 percent demand-related, and were allocated to all customers. Plastic pipes were classified using a minimum system method, and allocated to all customer classes except the ICGS class, because those customers all took service directly from the steel main system.[22]

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[19] Exhibit ACIG-C-0008 pages 51-53 and Exhibit B-0023 page 49.

[20] See Pennsylvania Public Utility Commission Docket No. R-2014-2406274.

[21] Mr. Russell Feingold of Black & Veatch served as an expert witness for Peoples TWP in that proceeding. See Pennsylvania Public Utility Commission Docket No. R-2013-2355886.

[22] See New Brunswick Energy & Utilities Board Matter 253.

IS THE COMPANY'S PROPOSAL TO MOVE FROM A REGIONAL MAINS CLASSIFICATION METHOD TO A GLOBAL SYSTEM METHOD REASONABLE?

Conceptually, moving away from regional detail to system detail moves away from the principle of matching costs with the customers who use the system and toward a method that relies more heavily on arbitrary allocation.[23] However, in practice, the Company's current method does not really reflect regional differences in costs due to data limitations.[24] Thus, it does not appear that there is any material reduction in accuracy related to moving away from the existing method.

SHOULD DISTRIBUTION MAINS COSTS BE ASSIGNED TO THE THREE GAZ MÉTRO CUSTOMERS WHO ARE ATTACHED DIRECTLY TO THE COMPANY'S TRANSMISSION SYSTEM?

No. The cost causation and decomposition principles dictate that customers who do not use the supply and distribution systems should not be assigned costs for that system. To the extent that specific equipment costs are incurred in order to attach these customers, those costs should be assigned directly to the appropriate rate classes. The customer and demand allocation factors used for allocating distribution system costs should therefore exclude the effects of the customers attached directly to the transmission system.

OVERALL, WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S PROPOSAL TO MOVE FROM REGIONAL ZERO-INTERCEPT ANALYSIS WITH SEPARATE DISTRIBUTION AND SUPPLY MAINS ALLOCATION TO A GLOBAL MINIMUM SYSTEM APPROACH WITH DEMAND ALLOCATOR ADJUSTMENT?

Without a detailed assessment of specific aspects of the system, there is no perfect method for allocating mains costs. Directionally, I believe there would be value in attempting to identify the customers and loads served at supply pressure, and allocating only supply mains costs to these customers, while allocating both supply and distribution mains costs to customers served at lower operating pressures. However, the Company appears to have concluded that it does not have sufficient data to follow this approach.

In light of the data limitations, I conclude that the Company's proposal is not obviously outside the range of industry practice, and has certain directionally reasonable attributes. In general, I agree with the Company that, absent a detailed cost allocation analysis,

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[23] Note that the current rate policy for Québec is that of postage stamp rates, which necessarily implies that the lower-cost regions are "cross-subsidizing" the higher-cost regions. If cost allocation is evaluated in detail at a regional level, continuation of the postage stamp régime would imply that the regional cross-subsidization would all occur intra-class, such that residential customers in low-cost regions would cross-subsidize residential customers in high-cost regions, etc. As rate design issues are deferred to Phase II of this proceeding, it is not clear how the results of any regional cost analysis will be applied to rates.

[24] Exhibit C-ACIG-0008, pages 47-49. Despite the data concerns cited in this reference, the Company appears to be able to undertake an alternative approach to regional cost allocation. Exhibit B-0045, item 13.2.

mains costs should be classified into demand-related and customer-related components, reflecting cost causation factors. The minimum system method is one of the standard approaches for such classification, and Dr. Overcast's adjustment to the demand allocator at least directionally attempts to address the primary complaint regarding that methodology, namely the load-carrying capability of the minimum system.

Compared to the existing approach, the primary advantage of the Company's proposal is simplicity and stability. Detailed regional classification analysis is eliminated, as is the need to evaluate alternative functional forms and address other uncertainties in the zero-intercept analyses.

However, the disadvantages of the proposed approach are (a) it adopts a methodologically weaker approach, particularly in its use of an arbitrary adjustment to the demand allocation factor, (b) it moves no closer to a more detailed effort to better match costs with the customers and customer classes who cause those costs to be incurred, both by eliminating the regional detail and by not more accurately segregating costs and customers served by operating pressure.

TURNING TO MORE TECHNICAL ISSUES, WHY ARE HISTORICAL MAINS COSTS ADJUSTED FOR COST INFLATION IN MINIMUM SYSTEM AND ZERO-INTERCEPT ANALYSES?

In performing either zero-intercept or minimum system mains classification analyses, utilities must derive the average cost of mains by diameter and type of main. Since utilities incur mains capital costs over a long period of time, utilities need to rely on data from an extended period to develop reasonable cost estimates by size of pipe. Since cost inflation can have a significant effect on mains costs, it is necessary to "deflate" costs incurred in different years, so as to produce inflation-adjusted average costs for mains by pipe size.

In addition, by deflating mains costs, the classification factor applied to mains better reflects the replacement cost for mains assets, rather than the depreciated book cost. For example, on an inflation-adjusted basis, a utility like Gaz Métro has significant investment in older, larger-diameter and more expensive steel pipe that would be expensive to replace, but which has a relatively low value in its current rate base. By deflating costs in the classification analysis, Gaz Métro better recognizes the replacement cost of that steel pipe in its cost allocation.

WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE?

The Company currently uses a Québec consumer price index (IPC) for deflating construction costs, and it proposes to switch to the use of "Handy-Whitman" ("H-W") gas utility mains construction cost indices for the northeast U.S., which are segregated between costs for steel mains and plastic mains.[25]

DOES THE COMPANY DEFLATE ALL OF ITS COSTS BASED ON THE YEAR OF CONSTRUCTION?

Unfortunately, it does not. Steel mains installed before 1979 are all treated in the price deflation calculation as having been installed in 1979, despite the fact that they may have been installed much earlier.[26] Thus, the price deflator applied to those mains tends to understate the cost of those steel mains. Not surprisingly, the inflation-adjusted unit cost of the steel mains recorded in 1979 is far below the costs recorded for the early 1980s. I expect that the directional bias of this over-simplification is to *overstate* the minimum system value for the customer component of costs. Because steel mains are generally of larger diameter and higher cost than the minimum system mains, increasing the weighting toward steel mains should tend to reduce the relative value of a 2-inch plastic main. Moreover, this effect could arguably be deemed to be significant, as some 46 percent of steel mains are recorded as having been installed in 1979. Alternatively, a reasonable case can be made that mains installed before 1979 are almost fully depreciated at present, and thus their impact on the revenue requirement is relatively small.[27] As such, the best approach may be to simply exclude those mains from the classification analysis.

DOES THE COMPANY'S APPROACH REFLECT THE FACT THAT MUCH OF ITS STEEL MAINS PLANT WOULD BE REPLACED WITH LOWER-COST PLASTIC MAINS IF IT WERE TO BE BUILT TODAY?

No. Costs are simply deflated based on construction cost indices. In effect, the deflated costs show what reproducing the steel pipe would cost today. In reality, however, Gaz Métro would not replace much of the old steel main system with steel today, but would instead use plastic mains. If Gaz Métro were to explicitly recognize that much of its steel pipe would be replaced with plastic pipe, the customer proportion of cost would likely increase. Based on the estimates provided by the Company, I estimate that factoring

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[25] "The Handy-Whitman Index of Public Utility Construction Costs" presents a series of cost indices for various types of construction costs for electric, gas and water utilities (as well as the construction industry), currently published by Whitman, Requardt and Associates ("WRA"). These cost indices have generally been published since 1924, and reflect cost trends since 1912. The basic intent of the indices is to allow for the estimation of reproduction cost for certain utility assets, based on the original book cost of the asset. For the gas utility industry, cost indices are derived for six regions of the United States. Gaz Métro proposes to use the indices for the North Atlantic region, which consists of twelve states stretching from West Virginia to Maine. With respect to mains costs, separate indices are calculated for cast iron, steel and plastic mains.

[26] Exhibit B-0058, item 32(a).

[27] As I understand it, the system in place in 1979 consisted almost entirely of steel mains, and served only the Montréal area. A significant share of the mains footage was 2-inch pipe, virtually all of which would be replaced by plastic if installed today.

mains replacement into the minimum system calculation would increase the customer component for distribution mains (excluding supply mains) from 74.2 percent to 80.7 percent.[28] Similar results would result by reflecting replacement in the zero intercept calculations.[29]

IS THE COMPANY'S PROPOSAL TO REPLACE THE IPC WITH THE HANDY-WHITMAN ("H-W") INDEXES FOR COST DEFLATING REASONABLE?

It is common practice for utilities in the U.S to use the H-W indices for deflating costs. However, it is not clear that the indexes proposed by Gaz Métro are reasonable. By definition, these indexes do not apply to Québec costs denominated in Canadian dollars, as they were developed for the northeastern U.S. and are denominated in U.S. dollars.

It is important to recognize that this change in cost indexes has a surprisingly significant impact on allocated costs, under the Company's methodology. Based on Gaz Métro's simulator in Exhibit B-0041, simply switching from the IPC to the H-W indexes reduces mains costs assigned to D1 class by more than 10 percent, and increases costs assigned to the D4 and D5 classes by more than 60 percent. This occurs because the H-W index for steel pipes imply significantly more cost inflation than does the index currently used by Gaz Métro.

Second, the H-W indexes appear to overstate cost inflation, particularly for Gaz Métro's steel mains. To evaluate this, I compiled the cost information presented in Exhibit B-0033 and totaled mains costs and footage by type of main, diameter of main, and by year. I then adjusted the yearly average cost per meter of main by main type for each year using the H-W index proposed by the Company. (I also eliminated observations where less than 1,000 meters of a particular type and size main were constructed in a particular year, to reduce the impact of relatively small cost items.) I then reviewed the annual unit costs for each diameter and type of pipe for any observable trends. For both plastic and steel pipe, the inflation-adjusted mains costs generally decline over time, although the effect is much more pronounced for steel pipe. While there is considerable scatter in the results, the inflation-adjusted cost of steel pipe exhibits a noticeable and statistically significant downward trend for the major pipe diameter categories. A sample of the results is shown in Figure IEc-1 below, for the three major steel pipe diameter categories.

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[28] See Exhibit B-0058, item 31(a), for the Company's assessment of replacement mains.

[29] Note that this effect may be reduced if an alternative price deflator were applied, particularly to steel mains, as discussed below.

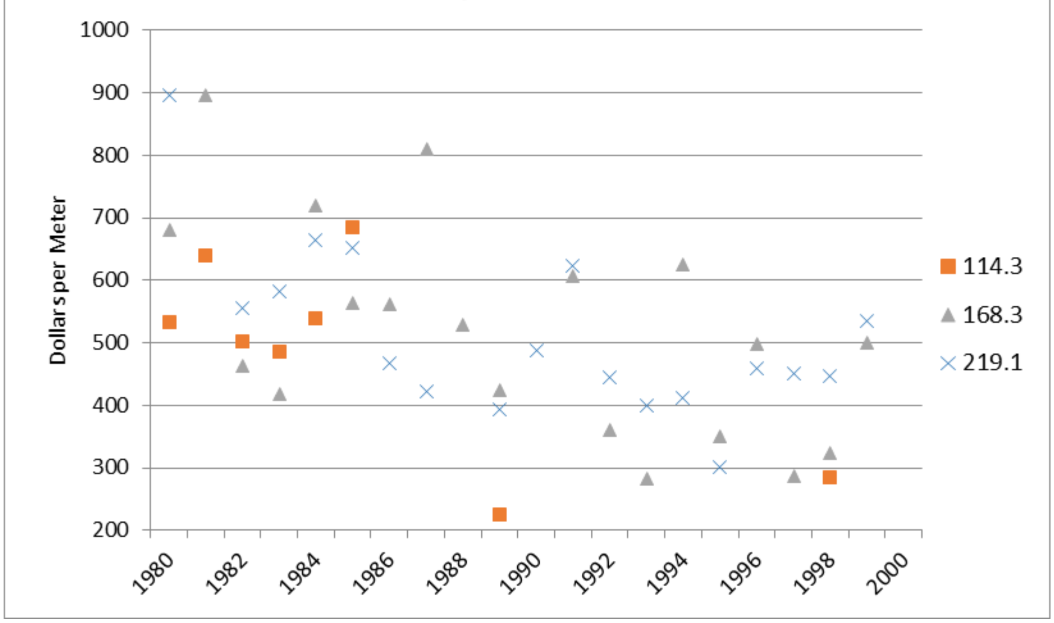

Figure IEc-1

H-W Inflation Adjusted Steel Mains Unit Cost

This pattern suggests that the H-W index overstates the effect of cost inflation when applied to the Gaz Métro construction costs. In light of the large impact this deflator has on allocated costs (using the Company's proposal), I recommend that the Company select a price deflation index that is consistent with its own construction cost experience.

IS THE CHOICE OF A PRICE DEFLATOR AS IMPORTANT IF THE ZERO-INTERCEPT METHOD IS RETAINED?

If a zero-intercept method is applied separately to steel mains and plastic mains as I indicated earlier, the choice of a price deflator has a much smaller impact than under Dr. Overcast's proposed approach. Based on my analysis of the "global" data (using separate regressions for steel and plastic pipe), the customer component of costs varies only slightly based on the choice of index, at 67.1 percent using the H-W index and 67.8 percent using the IPC. In contrast, the Company's proposal to base the minimum system value only on plastic pipe means that the customer component of cost is 59.8 percent if the H-W index is used but 74.6 percent if the IPC is retained. In effect, if the cost of the minimum system reflects both steel and plastic mains, the large differences between the H-W deflators for steel and plastic construction have a much smaller overall effect.

IN DEVELOPING ITS MINIMUM SYSTEM ESTIMATES, HOW DOES GAZ MÉTRO TREAT COSTS FOR PIPE INSERTS?

As I understand it, Gaz Métro includes the cost of plastic main inserts in the average costs for deriving the average cost of mains. Gaz Métro is unable to determine from its databases whether the original mains costs into which the new mains are inserted are or are not included in the dataset.[30]

IS THIS APPROACH REASONABLE?

As a theoretical matter, I do not believe that it is. The cost of the minimum system (or zero intercept pipe) should be based on the cost of installing new pipe. It should not reflect the incremental cost of inserting new pipe into existing pipe. By including the cost of pipe inserts in the average cost of plastic pipe, it would be reasonable to assume that the Company would be understating the replacement cost of plastic pipe, since one might expect the cost of inserts to be less than the cost of new construction. In general, this would likely serve to understate the minimum system, because a significant majority of the plastic inserts are 2-inch mains. However, based on the analysis that I have at this writing, the actual deflated costs of the plastic inserts are not substantially different from the costs of new construction, so modifying the minimum system to exclude plastic inserts would have little impact on the unit cost of the minimum system.

LET'S MOVE AWAY FROM MAINS COST CLASSIFICATION ISSUES AND ONTO ALLOCATION ISSUES. DO YOU AGREE WITH THE USE OF A DESIGN PEAK DEMAND ALLOCATOR FOR DISTRIBUTING DEMAND-RELATED COSTS AMONG THE VARIOUS RATE CLASSES?

I do. In this respect, I agree with the Company and Dr. Overcast, that it is more appropriate to allocate mains demand-related costs with a peak demand allocator than with the CAU hybrid allocator. As I noted earlier, the distribution system must be capable of meeting customer demand during extreme conditions and it is sized accordingly. Therefore, to the extent practicable, the design allocator for demand-related costs should reflect the maximum demands for which the system was designed.

DOES YOUR AGREEMENT EXTEND TO APPLYING THE DESIGN DEMANDS FOR INTERRUPTIBLE CUSTOMERS IN THE DISTRIBUTION DEMAND ALLOCATOR?

Yes, it does. Gaz Métro indicates that distribution mains are sized to meet the peak demands of interruptible customers. As such, distribution demands should be allocated to this class of customers.[31] I recognize, of course, that this change increases costs assigned to some ACIG members.

DO YOU HAVE ANY CONCERNS REGARDING GAZ MÉTRO'S DETERMINATION OF THE DESIGN DEMAND FACTORS USED IN THE COST ALLOCATION STUDY?

Gaz Metro's method for deriving design demands for cost allocation purposes is relatively simple, it has some inconsistencies between the classes, and it is not clear that it

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[30] Exhibit B-0058, item 24(c).

[31] Exhibit B-0023, page 29.

is consistent with system design criteria. I therefore have certain recommendations for additional analyses that Gaz Métro or the Régie may wish to pursue in this respect.

For the D1 and D3 rate classes, Gaz Métro calculates design day demand for cost allocation purposes using a linear regression analysis of monthly consumption data for one year.[32] This regression analysis determines a statistical relationship between monthly load and weather factors. Weather factors are evaluated using heating degree days, or heating degree days and average windspeed. (Including windspeed as an exogenous variable in the monthly regression analysis has virtually no effect on the calculated design day.) The fitted equation is then used to calculate design day demands by applying design temperature and windspeed parameters on a per-day basis.

There are a number of potential problems with this approach. First, Gaz Métro does not design its distribution to meet maximum daily demands but in fact designs it to meet maximum hourly demands.[33] As maximum hourly demands tend to be more extreme than maximum daily demands, the cost allocation parameters likely understate the actual design impact of weather factors. Also, because this estimate is based on class-wide monthly data, it is essentially an estimate of class coincident peak demand. While load diversity in the weather sensitive classes is not large, it is likely there is some regional diversity that must be reflected in the design of the system. Thus, the method tends to understate the demand requirements of the Rate D1 and D3 customers by using a coincident peak approach, as compared to the use of customer-specific non-coincident peak demands for Rates D4 and D5. In addition, the use of daily maximum demands is internally inconsistent with the apparent use of maximum hourly demands for D4/D5 customers.

Further, the use of monthly data may conceal problems in the estimation of design day demands. Unfortunately, Gaz Métro, like other NGDCs, concludes that its statistical analysis is valid because produces a good statistical "fit" based on the statistical metrics for the regression (notably the "R^2" term). However, the regression statistics provide a false sense of confidence due to the inclusion of summer loads in the statistical analysis. While including summer loads in the regression may make the statistician happier, it is unfortunately true that summer loads are irrelevant to cold weather demand levels. It is not unusual to observe different statistical relationships between load and temperature when the analysis is limited to cold weather periods, including both different weather

[32] At this writing, I am unable to reconcile the load data used in the regression analyses or the resulting DQMs (Exhibit B-0060) with the information presented in the cost allocation study (Exhibit B-0040). These inconsistencies result in some unusually high implied load factors in the cost allocation study for the D3 rate classes, especially D305 (an apparent 163 percent load factor).

[33] Exhibit B-0058, item 14(h).

coefficients and non-linear relationships between load and temperature. (Under very cold conditions, consumption may increase more than linearly with heating degree days.)

Gaz Métro responds to these concerns by observing that it does not have hourly or daily load data by rate class by which it could evaluate class-specific design conditions more carefully.[34] Nevertheless, as most D4 and D5 classes are hourly metered, Gaz Métro can presumably determine its actual total hourly load for the weather sensitive classes by deducting D4/D5 load from total sendout. At a minimum, Gaz Métro could then validate its design demand equations by comparing the actual weather sensitive load during extreme hours with the implied hourly demand from its equations for all of the temperature sensitive classes for those hours. To the extent that the equations substantially over- or under-predict weather sensitive hourly load under extreme conditions, it would be reasonable to develop an adjustment factor to "true-up" the estimated design demands to be consistent with the hourly demands used for system design.

For the D4/D5 classes, Gaz Métro generally relies on contract maximum hourly demands ("MHDs") for determining the demand allocator. In theory, this is a reasonable approach, if contract demands represent design conditions. However, it is not clear that this is the case. First, based on a comparison of contract demands and actual maximum hourly demands in Exhibit B-0061, it is apparent that there are a number of customers who have exceeded their contract demands over the past three years. The "excess" demand for these customers was some 5 to 9 percent above the contract demand, when summed across customers. As there is no current rate penalty for a customer exceeding contract demand, this pattern is not surprising. (At this writing, it is not clear to me whether such excess demand is interruptible.) In addition, roughly one-third of the D4/D5 customers had actual maximum hourly demands over a three-year period at less than 80 percent of contract maximum hourly demands, suggesting that some contract demands may be overstated. Thus, to the extent that contract MHDs are used for cost allocation, Gaz Métro should take steps to ensure that those MHDs are consistent with actual maximum demands.

3. TRANSMISSION COST ALLOCATION

PLEASE DESCRIBE THE COMPANY'S PROPOSED METHOD FOR ALLOCATING TRANSMISSION COSTS.

Gaz Métro proposes to classify transmission-related costs as 100 percent demand-related. While Dr. Overcast recommends that these be allocated based on design demand only to firm service customers, the Company proposes to retain the use of the CAU hybrid allocation factor and allocate transmission costs to both firm and interruptible customers on that basis. With the aggregation of supply and distribution mains, transmission mains

[34] Exhibit B-0058, item 14(f).

are limited to those mains operating at 4,400 kPa or higher, and represent only about $13 million of about $890 million in total net mains plant costs.

WHAT IS THE CAU ALLOCATION FACTOR?

The CAU factor is a peak demand allocation factor that is adjusted to ensure that the peak demand for each rate class is at least as high as the average demand. To derive the CAU allocator, first, all classes whose average demand exceeds their peak are assigned a CAU demand allocation factor equal to average demand. Second, the other rate classes whose peak demands exceed average demand are credited for these "excess" demands, in proportion to their respective differences between peak and average demands. Thus, in total, the CAU demand allocator has the same numerical total as the CA maximum day allocation factor, although the demands for the various classes are adjusted up and down.

Note that, if all rate classes have maximum day load factors below 100 percent (meaning peak demand exceeds average demand), the CAU allocator is equivalent to the CA maximum day allocation factor. In effect, the CAU allocator is a mechanism for increasing costs assigned to interruptible customers (or other customers with higher off-peak demands), and reducing costs assigned to firm, on-peak customers.

THE CAU FACTOR IS BASED ON A COMBINATION OF PEAK DEMAND AND THROUGHPUT (COMMODITY) ALLOCATION FACTORS. DOES IT PRODUCE RESULTS THAT LIE BETWEEN THESE TWO ALLOCATION FACTORS?

No, it does not. As such, it is fundamentally unlike the more common "peak and average" or "average and excess" allocation factors used in other jurisdictions. For example, the CAU allocator for the D409 sub-class is 8.69 percent, whereas the design allocation factor (excluding interruptible) is 9.06% and the throughput allocation factor is 9.84 percent.

DO YOU AGREE WITH THE USE OF THE CAU ALLOCATION FACTOR FOR ASSIGNING TRANSMISSION MAINS COSTS AMONG THE RATE CLASSES?

No. In this respect, I agree with Dr. Overcast. Like distribution mains, transmission mains must be sized to meet peak demands, and they must be extended to interconnect lower pressure supply and distribution systems. It is relatively common practice to allocate transmission costs entirely on the basis of a demand measure. Unlike Gaz Métro's upstream assets, Gaz Métro's transmission mains must provide annual transportation, seasonal transportation, and load balancing functions, because Gaz Métro does not have on-system storage by which it can levelize its use of transmission mains. Thus, transmission mains must be sized to meet peak demands of all downstream customers.

Further, I also agree with Dr. Overcast that demands from interruptible customers should be excluded from the peak demand allocator for the transmission system. As I understand it, Gaz Métro does not include interruptible customer demand in designing its transmission assets, and it may interrupt customers as a result of transmission constraints.[35] As such, interruptible customers do not cause Gaz Métro to incur any transmission costs.

SHOULD THE PRINCIPLE OF FAIRNESS BE APPLIED TO THE DEMAND ALLOCATOR FOR TRANSMISSION MAINS COST, SUCH THAT INTERRUPTIBLE CUSTOMERS WHO USE THOSE MAINS ARE ASSIGNED SOME MEASURE OF COSTS RELATED TO THOSE MAINS?

In my view, the principle of fairness is better applied at the rate design stage of the process. Interruptible customers do not cause Gaz Métro to incur transmission costs, and Gaz Métro appears to achieve some material savings in costs associated with not sizing transmission mains to meet interruptible demand.[36] Replacing the fundamental principle of cost causation in a cost allocation study with the fairness principle undermines the credibility of the cost allocation analysis. To the extent that the Régie determines that interruptible customers should pay a premium over the costs they cause in order to reflect this perceived idea of fairness, I recommend that it be implemented in the rate design process, rather than by polluting the cost allocation analysis.

4. METERS AND SERVICES COST ALLOCATION

HOW DOES GAZ MÉTRO PROPOSE TO ALLOCATE SERVICE LINE COSTS?

According to the text of Exhibit B-0024, the Company proposes to allocate services costs based on the historical average cost of a connection for each rate class as applied to the number of connections, plus a meter installation cost for each meter that is not associated with a connection. So, for example, a residential development with ten meters and one connection will be assigned services costs equal to the average residential connection cost for one customer plus nine times the average cost for the installation of a residential meter.

IS THIS A REASONABLE APPROACH?

Based on the information available to me at this writing, I believe this is a reasonable approach. Because Gaz Métro includes meter installation costs in its service line asset accounts, it is logical for the Company to estimate unit services cost based on number of connections (inclusive of the cost of installing one meter) and add in meter installation costs for each meter not counted with the service.[37] However, ACIG requested that Gaz Métro provide the details of this allocation in Exhibit B-0058 item 9(a), and the response refers to the electronic version of the proposed cost allocation study (Exhibit B-0040). Unfortunately, the electronic cost allocation study shows only the application of the cost

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[35] Exhibit B-0023, pages 59-61.

[36] Exhibit B-0058, item 38(b).

[37] Exhibit B-0058, item 9(i).

per connection to each class, and contains no information regarding the meter installation cost adjustment. As such, it is not clear at this writing that Gaz Métro is implementing the proposal as drafted.

HOW DOES GAZ MÉTRO PROPOSE TO ALLOCATE METERS COSTS?

My understanding of the methodology used for meters cost is based on the Company's presentation in the second technical session.[38] The language in Exhibit B-0024 does not appear to be fully consistent with that presentation.[39]

The Company calculates an average cost for each type of meter over the past three years. This cost is based on a weighted average of the cost of a new meter and a refurbished meter. This cost is then adjusted to reflect the expected life of the meter, by multiplying the average meter cost by the ratio of 20 (the expected life of an S20 meter) to the expected life of the meter. This adjusted meter cost value is then multiplied by the number of meters of each type in each rate class.

HAVE YOU BEEN ABLE TO REVIEW THE CALCULATIONS?

No. ACIG requested detailed workpapers for the development of the FS22 meters cost allocation factor in Exhibit B-0058, item 10(a). The Company's response pointed to the FS22 tab of the proposed cost allocation study (Exhibit B-0040). However, that electronic file contains only a simple average meter cost by class, and does not include the many details specified in the Company's methodology (e.g., meters costs, refurbishing costs, weighting factors, etc.). In addition, the description at Exhibit B-0058 indicates that a "metering equipment" cost item is added in the allocation factor, and that cost item is not shown in the cost allocation study.

AS A THEORETICAL MATTER, IS THE COMPANY'S APPROACH REASONABLE?

In general, the use of a historical average cost per meter is a common and reasonable approach. Moreover, the Company's desire to reflect the different lifespans of the meter, while uncommon, is certainly justified, given the very different expected lives of the different meter types (ranging from 5 to 20 years). However, the Company's adjustment mechanism to reflect differential meter lifespans does not appear to be reasonable.

The costs which are allocated using the FS22 allocator are meters plant and meters depreciation. The meters plant item is then used within the cost allocation study to determine the return and income tax costs associated with those assets.

In respect of depreciation costs, I believe that the Company's proposed adjustment mechanism is reasonable. If the typical meter for a D4 customer lasts only 5 years

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[38] Gaz Métro Presentation: Vision Tarifaire: Allocation des coûts – Séance de travail 1, 17 avril 2014.

[39] The formula shown in that tab does not explicitly recognize that historical costs are compiled by meter type, and then applied to number of meters of each type used within each rate class.

compared to a 20 year life for a typical residential meter, it is reasonable to adjust the unit meter depreciation cost for D4 customers by the ratio of 20:5. However, the same logic does not apply to return and taxes.

Table IEc-2 below presents a comparison of the regulatory costs associated with a $5000 meter with a 5-year useful life (Meter A) and a $5000 meter with a 20-year useful life (Meter B). For the purposes of this example, no inflation in meters cost is assumed, and a pre-tax weighted average cost of capital ("WACC") of 10 percent is applied. (Thus, the "return" value reflects both return and income taxes.) As shown, over the 20-year period, Meter A is purchased four times and Meter B is purchased once. Depreciation cost for Meter A is indeed four times that of Meter B. However, the return and income tax costs, measured by multiplying the pre-tax WACC by the prior year-end book value, are actually slightly lower for Meter A than for Meter B when measured on a levelized cost basis.

Table IEc-2: Regulatory Cost for Meters Investment

	Meter A: Five-Year Useful Life					Meter B: Twenty-Year Useful Life					Regulatory Cost Ratio	
Year	Capital	YE Book	Dep'n	Return (10%)	Rev. Req.	Capital	YE Book	Dep'n	Return (10%)	Rev. Req.	Dep'n	Return
0	5,000	5,000			11,229	5,000	5,000			5,000		
1		4,000	1,000	500	1,500		4,750	250	500	750	4.0	1.0
2		3,000	1,000	400	1,400		4,500	250	475	725	4.0	0.8
3		2,000	1,000	300	1,300		4,250	250	450	700	4.0	0.7
4		1,000	1,000	200	1,200		4,000	250	425	675	4.0	0.5
5	5,000	5,000	1,000	100	1,100		3,750	250	400	650	4.0	0.3
6		4,000	1,000	500	1,500		3,500	250	375	625	4.0	1.3
7		3,000	1,000	400	1,400		3,250	250	350	600	4.0	1.1
8		2,000	1,000	300	1,300		3,000	250	325	575	4.0	0.9
9		1,000	1,000	200	1,200		2,750	250	300	550	4.0	0.7
10	5,000	5,000	1,000	100	1,100		2,500	250	275	525	4.0	0.4
11		4,000	1,000	500	1,500		2,250	250	250	500	4.0	2.0
12		3,000	1,000	400	1,400		2,000	250	225	475	4.0	1.8
13		2,000	1,000	300	1,300		1,750	250	200	450	4.0	1.5
14		1,000	1,000	200	1,200		1,500	250	175	425	4.0	1.1
15	5,000	5,000	1,000	100	1,100		1,250	250	150	400	4.0	0.7
16		4,000	1,000	500	1,500		1,000	250	125	375	4.0	4.0
17		3,000	1,000	400	1,400		750	250	100	350	4.0	4.0
18		2,000	1,000	300	1,300		500	250	75	325	4.0	4.0
19		1,000	1,000	200	1,200		250	250	50	300	4.0	4.0
20		0	1,000	100	1,100		0	250	25	275	4.0	4.0
	Levelized Payment ==>		1,000	319	1,319	Levelized Payment ==>		250	337	587	4.0	1.2
		A:B Ratio ==>	4.00	0.95	2.25							

I therefore conclude that while the adjustment for the useful life of the meter is appropriate for allocating meter depreciation costs, it is not appropriate for meter plant costs. I suggest that, to accurately reflect differences in useful life, Gaz Métro apply different allocation factors for meter depreciation and meter plant.

5. MISCELLANEOUS ISSUES

PLEASE ADDRESS GAZ MÉTRO'S PROPOSAL FOR ALLOCATING WORKING CAPITAL.

Working capital costs generally represent the financing costs incurred by utilities related to the time delay between the time when the utility must make cash payments for the cost it incurs and the time when it receives cash payment from ratepayers. Gaz Métro's rate base includes some $25.8 million in working capital cost, primarily relating to cash and materials and income tax items. Gaz Métro, like other utilities, determines its working capital requirements based on "lead-lag" studies, wherein an average time lag between cash expenditure and cash receipt is calculated. In so doing, Gaz Métro includes an average bill payment lag for all customers on its system.[40]

Gaz Métro proposes to allocate its cash and materials working capital requirements based on overall O&M costs (EXPLOITD), and its income tax costs on the basis of overall rate base (BASETARD). In practice, however, it is often the case that the bill payment lag varies considerably among rate classes, such that some classes are disproportionately responsible for working capital costs. The simple aggregate EXPLOITD and BASETARD allocators do not reflect these differences.

I therefore suggest that Gaz Métro evaluate payment lag differences by rate class. To the extent these differences are material, I recommend that it develop weighting factors to apply to the working capital allocators to reflect differences in overall payment lag among the various rate classes.

PLEASE EXPLAIN HOW COSTS FOR GAZ MÉTRO'S ENERGY EFFICIENCY PLAN ARE ALLOCATED.

Gaz Métro incurs substantial costs associated with its energy efficiency plan (PGEÉ), including some $18.3 million in program costs and $4.3 million in program incentives costs. According to Exhibit B-0024, these costs are segregated into three categories: financial assistance costs, operating budget costs related to plan operations, and operating budget costs related to studies and administration. These costs are allocated as follows:

- The financial assistance costs, which represent that largest share of costs (82 percent of the PGEÉ allocator), are directly assigned to the rate classes to which the assistance applies.
- The operating costs are directly assigned by program into three customer groups (D1 residential, D1 non-residential/D3, and D4/D5) and then allocated within those groups based on a 50/50 weighting of total revenues and volumes.

[40] Exhibit B-0058, item 18.

- The studies/administrative costs are subjectively assigned to the three customer groups, and are then allocated within each rate class group based on a 50/50 weighting of total revenues and volumes.

IS THIS A REASONABLE APPROACH?

Based on the information available at this writing, I believe that the direct assignment of program costs is reasonable. Direct assignment of energy efficiency program costs is a reasonable approach, because the effects of those programs are reduced consumption and reduced peak loads. Reductions in overall load, as well as improvements in class load factor, serve to benefit rate classes in the cost allocation study in the form of reduced costs being allocated.

Regarding the allocation of program operating costs, although detailed workpapers were requested for the development of this allocation factor, the Company's response refers only to the proposed cost allocation study.[41] That study includes no workpapers, but simply reports volumes by class in each category.

By way of the values in the allocator, I note that the D4 class is responsible for 8.3 percent of the financial assistance costs, but is assigned 14.1 percent of the operating costs and 14.8 percent of the studies/administrative costs. While a discrepancy of this magnitude is a little surprising, Gaz Métro reports that the operating costs are directly assigned to the D4/D5 classes, so there is nothing obviously incorrect about the methodology. As long as Gaz Métro can demonstrate that the operating costs are, indeed, disproportionately incurred for the D4/D5 classes based on direct assignment of costs, the proposed approach is not unreasonable. However, if these costs are being subjectively allocated, a better approach may be to simply assign program operating and administrative costs in proportion the directly assigned financial assistance costs.

PLEASE COMMENT ON THE PROPOSED ALLOCATION METHOD FOR LOST AND UNACCOUNTED-FOR GAS.

Like many natural gas distribution utilities, the Company allocates lost and unaccounted for gas ("UFG") in proportion to annual throughput. However, some utilities conclude that larger users served at higher pressures have lower gas loss rates than customers served at lower pressure.[42] If Gaz Métro were moving the direction of sub-functionalizing its mains system and better matching costs with customers, it might be worth exploring more accurate methods for assigning UFG among the rate classes. In light of Gaz Métro's global approach to cost allocation philosophy, I conclude that Gaz Métro probably does not have sufficient data to accommodate such an effort at this time.

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[41] Exhibit B-0058, item 20(a).

[42] See, for example, Peoples TWP at Pennsylvania Public Utilities Commission Docket No. R-2014-2399598.

PLEASE ADDRESS THE COMPANY'S PROPOSAL FOR ALLOCATING INTERNAL SUPPORT SERVICES COSTS ON THE BASIS OF THE "EXPLOITD" FACTOR (O&M COSTS)?

This is a surprisingly large cost item, totaling some $55.7 million in costs, in effect representing a 43 percent markup on all other O&M costs. While the Company's proposal is not necessarily unreasonable, this cost category comprises a wide variety of costs, and some additional analysis of the specific costs included in this category and the factors causing those costs to be incurred would seem to be in order.

PLEASE ADDRESS THE COMPANY'S PROPOSAL WITH RESPECT TO THE ALLOCATION OF IT COSTS, INCLUDING THOSE RELATED TO THE SAP2B PROJECT.

For IT projects in general, the Company proposes to allocate costs to all classes in proportion to rate base (BASETARD). For the SAP2B project, in its discussion paper, the Company proposed to reflect the fact that much of the investment related to residential and commercial customer billing systems by allocating the costs 50 percent to all customers based on rate base (BASETARD) and 50 percent to residential and commercial customers only.[43] In response to discovery, the Company proposes to defer this issue to the rate design phase of the proceeding.[44] The filed cost allocation analyses continue to allocate the SAP2B costs using the rate base allocator. Based on the limited information available, I conclude that the Company's proposal in its discussion paper is directionally reasonable.

REGARDING REGULATORY AFFAIRS COSTS, DO YOU AGREE WITH THE COMPANY'S PROPOSED CHANGE IN ALLOCATION METHOD FROM "EXPLOITD" (O&M COSTS) TO THE "CA-CLIENT" FACTOR?

Regulatory affairs relate to all aspects of the cost of service. While the Company's proposal is not necessarily unreasonable, a better allocation factor would be total costs subject to regulation or total revenues subject to regulation.[45] There is no obvious causal relationship between regulatory affairs cost and a simple average of customer and commodity allocation factors.

PLEASE ADDRESS THE COMPANY'S PROPOSED ALLOCATION OF SALES AND ADVERTISING COSTS.

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[43] Exhibit C-ACIG-0008 pages 60-61.

[44] Exhibit B-0058, item 42.

[45] As a general rule, I favor a cost-based allocator over a revenue-based allocator, because revenue-based allocators tend to exacerbate revenue-cost differences that exist within a tariff structure. In essence, a class that is providing revenue in excess of allocated costs is implicitly punished for that excess, by being assigned higher costs. In this respect, I agree with the Company's response to the Régie in Exhibit B-0045 item 17.4.

Both sales costs and advertising costs consist of a portion of the costs that are directly assigned to rate class groups, and general expenses that must be allocated. Within each rate class group (e.g., Rates D4 and D5), the directly assigned costs are allocated based on a 50/50 weighting of number of customers and volumes.

Regarding sales costs, Gaz Métro incurs some $2.1 million in sales costs related to Rates D4 and D5. It is unclear what activities are included in these cost items, as only limited information was provided in response to ACIG's request, which indicates only that the vast majority of these costs are related to customer service - contracts. [46] As such, I cannot evaluate whether the direct assignment of costs to the D4/D5 classes is reasonable. Regarding advertising costs, only a minimum amount of about $0.05 million is directly assigned to the Rate D4/D5 group.

As to the allocation of general sales and advertising costs, Gaz Métro appears to assign excessive amounts to Rates D4 and D5. For the directly assigned costs, Rate D4/D5 customers are responsible for 14.2% of the costs (Factor FS27) and 2.5 percent of the directly assigned advertising costs (Factor FS28). In contrast, however, Gaz Métro proposes, however, to assign these classes 37.9 percent of both the general sales and general advertising expenses, using a total revenue allocator (Factor FB09-CL). A more logical approach would be to assign the general costs in each category in proportion to the directly assigned costs. In the case of sales costs, Gaz Métro indicates that the general costs are primarily related to other sales functions, and are therefore more logically allocated in proportion to those costs. For advertising, Gaz Métro reports that the general costs are related to "positioning campaigns, sponsorships, website redesign, etc."[47] Few, if any, of these costs are necessary to provide service to larger industrial customers, and there is therefore no basis to require large industrial customers to bear more than one-third of these costs as proposed by the Company. As such, allocating general advertising costs in proportion to the directly assigned advertising cost would be a more reasonable approach.

PLEASE COMMENT ON THE COMPANY'S PROPOSED ALLOCATION OF INTERVENOR EXPENSES.

In its description of the method used for allocating intervenor expenses (Factor FS31), Gaz Métro indicates that intervenor costs are directly assigned to the classes represented by specific intervenors, with public interest intervenor costs being allocated to all classes

[46] Exhibit B-0058, item 11(c).

[47] Exhibit B-0058, item 12(d).

based on an equal weighting of throughput (FB01D) and total revenues (FB09CL).[48] I have two concerns with this approach. First, regulatory expenses should be primarily focused on regulated services, namely transmission and distribution. There is therefore little reason to include volumes or gas supply revenues in the allocation of public interest costs. I suggest that the transportation/storage/distribution revenue allocator (FB10) be used for costs that are demonstrably related to the public interest. In addition, I note that some 44 percent of costs fall into an "other" category, which is not defined in the supporting materials.[49] This cost item is allocated using the FB10 allocator, which is reasonable to the extent that it applies to general regulatory expense.

PLEASE COMMENT ON THE PROPOSED ALLOCATION OF THE ENERGY EFFICIENCY FUND.

Exhibit Gaz Métro-2, Document 4 indicates that the FEÉ-FR Energy Efficiency Fund allocator is used to allocate costs between rates D1 and D3 based on distribution revenues (FB07D). The formulae shown in the cost allocation studies (Exhibits B-0039 and B-0040) indicate that this allocator includes revenues for D4 and D5 rate classes (although it is acknowledged that zero costs and rate base are allocated using this factor in that exhibit). This discrepancy should be clarified.

PLEASE ADDRESS THE COMPANY'S PROPOSED ALLOCATION METHOD FOR UTILITY NETWORK TAX.

Gaz Métro is subject to asset-based property taxes that apply to certain components of its distribution system, including distribution mains, service lines, city gate facilities, compressor stations facilities and LNG facilities.[50] Gaz Métro proposes to allocate its utility network tax on the basis of the CONDPRIN allocation factor, which is the allocator that reflects transmission plus distribution mains asset allocation. As the tax includes service line costs, and because these costs are material, a modified allocator should be developed which also includes service line costs.

PLEASE COMMENT ON THE COMPANY'S ALLOCATION OF LATE PAYMENT REVENUES.

The Company proposes to allocate some $2.8 million in late payment revenues (as an offset to allocated costs) in proportion to overall total revenues (FB09). However, the incidence of late payment charges varies from class to class. As the Company is presumably aware of which customers and which classes generate actual late payment

[48] In the MS Excel model, ACIG costs are assigned to the D4 and D5 classes, and allocated between classes based on transmission/storage/distribution revenues (FB10). The text of Gaz Métro-2, D4, page 19 does not appear to be consistent with the model, in that it states ACIG costs are allocated based on total revenues (FB09CL).

[49] These values may include costs incurred by the Régie for outside experts, per Exhibit B-0058, item 13(c).

[50] Exhibit B-058, item 23(a).

revenues, it should modify its method to base the allocation on the class-specific historical rates for late payment revenues.

6. SUMMARY OF CONCLUSIONS

MR. KNECHT, YOU'VE SPENT MANY PAGES DISAGREEING WITH OR EXPRESSING CONCERNS ABOUT A VARIETY OF THE COMPANY'S COST ALLOCATION PROPOSALS. ARE THERE ANY PROPOSED CHANGES WITH WHICH YOU AGREE?

In fact, I agree with a number of the Company's proposed changes, including the following:

- The Company reasonably proposes that the cost allocation study be (a) based on fully distributed costs, (b) ported to spreadsheet software, (c) performed annually, and (d) applied to future test year revenue requirements as an aid to revenue allocation and rate design.
- The Company's effort to conduct a detailed review of several of its data systems to compile a clean set of useful data is to be commended.
- The Company's proposal to allocate return and income tax on the basis of rate base is consistent with cost causation, and is a simple and straightforward approach.
- The Company's proposal to move away from the hybrid CAU allocation factor to alternative peak demand-based allocation methods is consistent with the principles of cost causation.

PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING CHANGES THAT SHOULD BE MADE (OR EVALUATED) TO THE COMPANY'S PROPOSED COST ALLOCATION APPROACH.

My conclusions and recommendations are as follows:

1. The Régie should adopt the principle that costs allocated to any individual customer or customer class should not exceed the standalone cost of service.
2. Regarding the classification of mains costs, Gaz Métro generally proposes to adopt a relatively simple, global, aggregate approach. Any effort to move toward a more detailed, focused approach that allocates system costs only to customers who use specific aspects of the system appears to be precluded by data constraints.
3. Given those constraints, the Company's options for classifying mains costs are limited to general cost classification approaches which are theoretically imperfect, but which are widely used. The Company's choice of the minimum system method, combined with a modified demand allocator, is generally within the range of methods currently in use, and is not necessarily unreasonable. The Company's proposal has advantages of simplicity and stability.

4. The zero-intercept method is also an accepted method for mains cost classification. Based on the information available at present, it does not appear that applying the zero-intercept method at a regional level produces sensible results. Thus, if the zero-intercept method is retained, I recommend that it be calculated at the global level, and that the customer component of cost be based on a weighted average of steel and plastic mains regression intercepts.

5. Given the Company's decision not to develop a more detailed allocation of supply mains costs, the Company's proposal to aggregate supply and distribution mains for cost classification and allocation purposes is reasonable and consistent with its overall mains cost allocation philosophy.

6. Distribution/supply mains costs should not be assigned to customers who take service directly from transmission lines.

7. The Company should identify and employ a price deflator for mains construction costs, particularly steel mains construction costs, that is consistent with its own construction cost experience. In addition, the Company should evaluate how best to treat mains installed before 1979 in its mains classification analysis, including potentially excluding those mains from the analysis. This task is particularly important if the minimum system is defined based only on the cost of plastic pipe.

8. In deriving system average classification factors, the cost weighting should be adjusted to reflect the fact that much of the existing steel mains system would be replaced with lower-cost plastic mains, particularly if a plastic-only minimum system approach is adopted..

9. Gaz Métro should review its design demand calculations for cost allocation purposes, and evaluate modifications to achieve the following:

    a. Ensure that design demands for cost allocation are reasonably consistent with design demands for system planning and operation;

    b. Ensure that design demands for each class are consistently estimated across classes, on a non-coincident peak demand and on an hourly basis;

    c. Ensure that the contract demands used for D4 and D5 customers reasonably reflect the design demands that Gaz Métro has an obligation to serve;

    d. Develop design demands for weather sensitive customers (net of daily metered customers) using daily or hourly sendout during cold weather periods. At a minimum, design demands for weather sensitive classes used in cost allocation should be validated against actual system sendout during extreme conditions.

10. Transmission costs should be allocated to firm service customers only, based on design demand levels.

11. The meters cost allocation method should be modified such that different allocators apply to depreciation (reflecting useful life) and rate base (reflecting unadjusted book value).

12. If bill payment lags vary materially by rate class, the allocation of working capital should be adjusted to reflect each class' relative contribution to the net payment lag.

13. Gaz Métro should continue its efforts to find more accurate approaches to allocating the large "support services" cost item.

14. The Régie and Gaz Métro should consider the other cost allocation recommendations detailed in this evidence, and adopt them as appropriate.

EXHIBIT IEc-1

CURRICULUM VITAE AND

EXPERT TESTIMONY SCHEDULE

OF

ROBERT D. KNECHT

R O B E R T D . K N E C H T

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than thirty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. Mr. Knecht also served as Treasurer of IEc from 1996 through 2010, and was responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans, during that period.

Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- For the New Brunswick Public Intervenor, Mr. Knecht has prepared expert testimony regarding electric and gas utilities, on various regulatory issues, including revenue requirements, amortization methods, system expansion economics, cost allocation, and rate design
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- As a participant on various international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency and other private and public entities.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates
Matter 225	New Brunswick Energy & Utilities Board	Energy Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories (“gas-on-gas”).
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program (“GET Gas”)
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.
R-2013-2341604	Pennsylvania Public Utility Commission	Peoples TWP	March 2013	Pennsylvania Office of Small Business Advocate	Retainage rates, design day demand forecast, allocation of demand costs, recovery of other gas costs
R-2013-2341534	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2013	Pennsylvania Office of Small Business Advocate	Unaccounted for gas, retainage.
R-2012-2333993	Pennsylvania Public Utility Commission	Philadelphia Gas Works	February 2013	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, uncollectible cost unbundling

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2012-2321748	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	January 2013	Pennsylvania Office of Small Business Advocate	Cost of capital, cost allocation, revenue allocation, gas procurement cost unbundling, rate design
R-2012-2327529	Pennsylvania Public Utility Commission	Peoples TWP	December 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, price to compare
R-2012-2314235 R-2012-2314224 R-2012-2314247	Pennsylvania Public Utility Commission	UGI Utilities Gas Division UGI Penn Natural Gas UGI Central Penn Gas	October 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, reconciliation, migration rider
P-2012-2302074	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design, reconciliation, working capital cost treatment.
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates
P-2011-2256365	Pennsylvania Public Utility Commission	PPL Electric Utilities	November 2011	Pennsylvania Office of Small Business Advocate	Default service reconciliation
Matter No. 132	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	October 2011	New Brunswick Public Intervenor	Revenue requirement, cost forecasting, system expansion economic test, regulatory deferral test, filing requirements.
R-2010-2161694 on Remand	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2011	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2011-2238943, R-2011-2238943, R-2011-2238949,	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2011	Pennsylvania Office of Small Business Advocate	Design day demand, mandatory capacity assignment, sharing mechanisms
C-2011-2245906, M-2011-2243137	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2011	Pennsylvania Office of Small Business Advocate	Reconciliation of default service costs and revenues
P-2011-2218683, P-2011-2224781	Pennsylvania Public Utility Commission	West Penn Power Company	April, May 2011	Pennsylvania Office of Small Business Advocate	Critical peak pricing, time-of-use pricing

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2010-2214415	Pennsylvania Public Utility Commission	UGI Central Penn Gas	April 2011	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, revenue allocation, non-residential rate design, EE&C cross-subsidies and cost recovery, natural gas vehicle subsidies
R-2010-2215623, R-2010-2201974	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	April 2011	Pennsylvania Office of Small Business Advocate	Cost of equity capital, cost allocation, revenue allocation, BTU adjustment mechanism, rate design, DSIC
NBEUB 2010-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	April 2011	New Brunswick Public Intervenor	Cost- and market-based ratemaking, transition mechanism
M-2010-2210316	Pennsylvania Public Utility Commission	UGI Utilities, Electric Division	March 2011	Pennsylvania Office of Small Business Advocate	Energy efficiency plan cost recovery, conservation development rider
A-2010-2213893, et al.	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	February 2011	Pennsylvania Office of Small Business Advocate	Asset valuation, reasonableness of proposed affiliate transaction
M-2009-2123944	Pennsylvania Public Utility Commission	PECO	January 2011	Pennsylvania Office of Small Business Advocate	Dynamic pricing cost allocation and rate design
NBEUB 2010-007	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	December 2010	New Brunswick Public Intervenor	Allowable costs, O&M capitalization policy, expansion cost effectiveness, incentive mechanisms
R-3740-2010	Régie de l'énergie, Québec	Hydro Québec Distribution	December 2010	AQCIE/CIFQ	Pension cost reconciliation, cross-subsidies, rate design
P-2010-2158084	Pennsylvania Public Utility Commission	West Penn Power Company	November 2010	Pennsylvania Office of Small Business Advocate	Transmission service charge, reconciliation timing
P-2010-2194652	Pennsylvania Public Utility Commission	Pike County Light & Power	November 2010	Pennsylvania Office of Small Business Advocate	Electric default service procurement, customer education

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
A-2010-2176520, A-2010-2176732	Pennsylvania Public Utility Commission	Allegheny Power/FirstEnergy Corporation	September 2010	Pennsylvania Office of Small Business Advocate	Implications of proposed merger for default service
App. No. 1605961, Proceeding ID 530	Alberta Utilities Commission	Alberta Electric System Operator	August 2010	BC Hydro	Transmission rate design
R-2010-2167797	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	July 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables, rate of return
R-2010-2172933, R-2010-2172922, R-2010-2172928	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
NBEUB 2010-002	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	June 2010	New Brunswick Public Intervenor	Cost allocation, rate design, deferral costs
R-2010-2161694	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2010-2161920	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, retainage rates, gas price forecasting
R-2009-2149262	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, rate of return
P-2009-2145498	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division)	April 2010	Pennsylvania Office of Small Business Advocate	Merchant function charge, purchase of receivables
R-2010-2157062	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
NBEUB 2009-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	March 2010	New Brunswick Public Intervenor	Cost allocation, deferral costs

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2009-2139884	Pennsylvania Public Utility Commission	Philadelphia Gas Works	March 2010	Pennsylvania Office of Small Business Advocate	Revenue requirement, cost allocation, rate design, DSM program
R-2010-2150861	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
R-2009-2145441	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
P-2010-2099333	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	February 2010	Pennsylvania Office of Small Business Advocate	Purchase of receivables
R-3708-2009	Régie de l'énergie, Québec	Hydro Québec Distribution	November 2009	AQCIE/CIFQ	Post-patrimonial generation cost allocation, revenue allocation
M-2009-2123944, 2123948, 2123950, 2123951	Pennsylvania Public Utility Commission	PECO, Duquesne Light, Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	October, November 2009	Pennsylvania Office of Small Business Advocate	Smart Meter Cost Allocation and Rate Design
NBEUB 2009-006	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2009	New Brunswick Public Intervenor	Development Period Criteria
M-2009-2092222, 2121952, 2112956, 2093218, 2093217, 2093215	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power, Duquesne Light, PPL Electric	August 2009	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation programs, cost allocation, rate design
1604944; ID# 184	Alberta Utilities Commission	ATCO Gas	July 2009	Rate 13 Group	Cost allocation, rate design
R-2009-2105904, 909, 911	Pennsylvania Public Utility Commission	UGI Penn Natural Gas, UGI Central Penn Gas, UGI Utilities Inc. Gas Division	July 2009	Pennsylvania Office of Small Business Advocate	Gas supply procurement hedging, unaccounted-for gas, revenue sharing mechanisms

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2009 TO 2014

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2009-2093219	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2009	Pennsylvania Office of Small Business Advocate	Revenue sharing mechanisms, retainage rate, gas procurement
R-2008-2079660	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2079675	Pennsylvania Public Utility Commission	UGI Central Penn Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2075250	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil	April 2009	Pennsylvania Office of Small Business Advocate	Retainage rates
R-2009-2088076	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2009	Pennsylvania Office of Small Business Advocate	Gas procurement
R-2009-2083181	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2009	Pennsylvania Office of Small Business Advocate	Retainage rates, gas procurement

Note: Dates shown reflect submission date for direct testimony.

Exhibit IEc-2

Documents Reviewed

Exhibit IEc-2

Documents Reviewed

1. Gaz Métro-1, Document 1: Review of Gaz Metro's Cost of Service and Rate Design (Black & Veatch) (B-0005)
2. Gaz Métro-1, Document 2: Discussion Paper on Gaz Métro's Cost of Service (English, C-ACIG-008)
3. Gaz Métro-2, Document 1: Gaz Métro Cost of Service Allocation (English, B-0023)
4. Gaz Métro-2, Document 2: Impact des Changements Proposés sur l'allocation des coûts (B-0017)
5. Gaz Métro-2, Document 3: Sommaire des Changements Proposés à l'allocation des coûts de Distribution (B-0018)
6. Gaz Métro-2, Document 4: Index of Distribution Cost Allocation Factors (English, B-0024)
7. Gaz Métro-2, Document 6: Allocation of Gaz Métro's Cost of Service Additional Evidence, Revised 22 December 2014 (English, C-ACIG-0023)
8. Gaz Métro-2, Document 7: Current cost allocation study, revised 22 December 2014 (MS Excel, English, C-ROEÉ-0029)
9. Gaz Métro-2, Document 8: Proposed cost allocation study, revised 22 December 2014 (MS Excel, English, C-ROEÉ-0030)
10. Gaz Métro-2, Document 9: Base de données comptables (MS Excel, B-0033)
11. Gaz Métro-2, Document 10: Base de données d'ingénierie (MS Excel, B-0034)
12. Gaz Métro-2, Document 11: How to Use the Supply and Distribution Mains Cost Allocation Simulation (English, C-ACIG-0024)
13. Gaz Métro-2, Document 12: Simulator (English, C-ROEÉ-0031)
14. Gaz Métro-3, Document 1: Response to Régie DDRs Set I (text and associated maps (B-0045 (translated), B-0048 to B-0055), regional and global classification analysis, Annexe 2 (B-0047))
15. Gaz Métro-3, Document 8: Response to Régie DDRs Set II (B-0072 (translated))
16. Gaz Métro-3, Document 10: Response to Mr. Chernick's DDRs Sets I and II (C-ROEÉ-0035, C-ROEÉ-0036, C-ROEÉ-0037)
17. Gaz Métro-3, Document 2: Responses to ACIG DDRs and certain appendices (B-0058 (translated), B-0060, B-0062,)
18. Gaz Métro-3, Document 2, Annexe 7: Evidence of Sharon L. Chown, R-3323-95, 30 April 1997 (B-0058)
19. Gaz Métro-3, Document 2, Annexe 8: Pre-filed Direct Testimony of H.J. Vander Veen, R-3313-94, R-3323-95, 15 December 1995. (B-0058)

20. Vision Tarifaire: Allocation des coûts – Séance de travail 1, 3 avril 2014
21. Vision Tarifaire: Allocation des coûts – Séance de travail 2, 17 avril 2014
22. Vision Tarifaire: Allocation des coûts – Séance de travail 3, 7 mai 2014
23. Information Complémentaires, undated document distributed by Gaz Métro on 6 May 2014 in response to questions raised during technical sessions (French only)
24. Conditions of Service and Tariff, December 11, 2013 (www.gazmetro.com/conditionsandtariff)

EXHIBIT IEc-3

ALGEBRAIC REVIEW OF GAS MAINS COST CLASSIFICATION METHODOLOGIES

Exhibit IEc-3

Algebraic Review of Gas Mains Classification Methods

The standard methods for classifying mains costs into demand-related and customer-related component include the “zero-intercept” method and the “minimum system” method. Both methods rely on a conceptual framework in which the customer-related cost is the cost of the utility’s gas distribution system if it were entirely composed of mains with minimal load carrying capability. In the case of the minimum system method, the theoretical system is based on the average per-foot cost of the smallest main that is commonly used on the system. In the case of the zero-intercept method, the theoretical system is based on a statistically-estimated cost of a zero-diameter main. The zero-intercept method is generally considered to be more theoretically correct, because the zero-intercept system has no load carrying capability.[51] (The minimum system method has significant practical advantages over the zero-intercept method, most notably with respect to avoiding both the need and the uncertainty surrounding the statistical analysis.) Therefore, this theoretical review evaluates the zero-intercept framework. The theoretical problems with the zero-intercept method are compounded by additional theoretical problems with the minimum system method, generally relating to the load carrying capability of the minimum system.

Consider first the simplest basic framework for the zero-intercept method:

$$\frac{Ci}{F_i} = a + b * K_i$$

$$CC_T = a * F_T$$

$$DC_T = C_T - CC_T = \sum^{i} (b * K_i * F_i)$$

where:

C, CC, DC = cost, customer cost, demand cost

F = mains footage[52]

K = mains carrying capacity, comparable to downstream customer demand

i = main diameter size

T = total system

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[51] Gaz Métro considers the zero-intercept method to be more theoretically correct. See, for example, Exhibit B-0023 page 22, Exhibit ACIG-C-0008 page 29.

[52] This exhibit uses feet as the assumed measure for mains length, in order to avoid confusion with the use of metric units wherein the term “cost per meter” may incorrectly be interpreted as a cost per measuring device rather than a cost per unit of length.

a, b = statistically estimated terms

In the simplest interpretation, this model splits costs into "fixed" and "variable" components, in which the "variable" costs related to the capacity of the mains are deemed to be demand-related and the "fixed" costs (as represented by the a * F_T term) are assumed to be related to number of customers. In this framework, the classification of the $\sum^{i} b * K_i * F_i$ term as demand-related is theoretically sound, as these costs are clearly proportional to demand. (Since main carrying capacity must be sufficient to meet peak demand, customer demand and main carrying capacity are equivalent.)

However, the obvious difficulty with this framework is that fixed costs are fixed, and there is not a strong theoretical basis for allocating those costs based on number of customers, peak demand, commodity throughput, or any other arbitrary factor. While there may be *rate design* advantages to recovering fixed costs with a customer charge, there is no cost causation reason for allocating truly fixed costs based on number of customers. This basic argument is often advanced by cost allocation practitioners who oppose zero-intercept or minimum system methods.

Moving on to a slightly more complicated interpretation of the zero-intercept model, it is often argued that mains footage is causally related to the number of customers on the system. So, in its simplest format, we add the equation that assumes system footage is linearly proportional to number of customers. The resulting equations then become:

$$F_i = \alpha_i * N$$

$$\sum^{i} \alpha_i = \alpha_T$$

$$CC_T = a * \alpha_T * N$$

$$DC_T = C_T - CC_T = \sum^{i} (b * K_i * \alpha_i * N)$$

where:

N = number of customers

In this model, we now have a rational basis for concluding that there is a causal relationship between mains costs and number of customers. Unfortunately, the model does not produce an accurate split between customer-related and demand-related cost. In this model, the costs that are deemed to be customer-related (CC_T) are, in fact, proportional to the number of customers. (See shaded "N" in DC formula.) However, the costs that are deemed to be demand-related are, in this model, causally related both to the capacity of mains and the number of customers. Thus, in this framework, the zero-intercept method will tend to *understate* the customer component of costs, because the costs that are deemed to be demand-related are proportional to both carrying capacity and number of customers.

We now move on to an additional layer of complexity. It may be credibly argued that the mains footage requirement for larger customers is higher than that for smaller customers.[53] This would imply that mains footage is causally related to both number of customers and customer demand. Dr. Overcast's cross-sectional statistical analysis is generally consistent with this hypothesis. While mains footage is substantially determined by number of customers, there is a modest observed effect of system demand on mains footage.[54] Adding this consideration into the model, the equations then become:

$$F_i = \alpha_i * N + \beta_i * D$$

$$\sum^{i} \beta_i = \beta_T$$

$$CC_T = a * \alpha_T * N + a * \beta_T * D$$

$$DC_T = C_T - CC_T = \sum^{i} ((b * K_i) * (\alpha_i * N + \beta_i * D))$$

where:

D = system demand

In this framework, we now see that the zero-intercept model has biases in two directions. First, the customer cost component as calculated by the zero-intercept method is causally related to both number of customers and system demand. (See shaded "D" in the CC formula.) Second, the demand-related component is also causally related to both number of customers and system demand. (See shaded "N" in the DC formula.)

Thus, even with some simple assumptions, the theoretical underpinning of the zero-intercept model breaks down pretty quickly. While the biases in this third incarnation of the model are in opposite directions, there is no reason to believe they exactly offset. Thus, the zero-intercept method can only reasonably be interpreted as an approximation. Without a detailed analysis of how mains footage per customer varies by different sizes of customer for each particular utility, there is no way to determine either the magnitude or direction of the bias in the zero-intercept method.

Thus, without a detailed assessment of the particular gas system to which it is applied, the zero-intercept model should be accepted for what it is – a rough approximation to cost causation.

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[53] In practice, the world is not so simple. Common sense may suggest that large customers are more spread out than smaller customers, but these customers may also locate closer to high pressure transmission lines. Medium-sized business customers may be concentrated in commercial areas, such that customer density is actually higher for larger customers than it is for smaller customers, implying a negative relationship between footage and demand. These complexities explain why simple factors cannot fully reflect the real world details of how costs are incurred.

[54] Exhibit B-0005, pages 14-15. Note Dr. Overcast uses throughput as a proxy for demand, based on data limitations.