In the Matter of
Centra Gas Manitoba
Cost of Service Methodology Review

Pre-Filed Testimony of
Patrick Bowman

Submitted to: Manitoba Public Utilities Board

On behalf of: Industrial Gas Users of Manitoba

Prepared by: Patrick Bowman

June 9, 2022

InterGroup CONSULTANTS

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APPENDICES

1.0 INTRODUCTION

This testimony has been prepared for the Industrial Gas Users ("IGU") of Centra Gas Manitoba ("CGM") by Patrick Bowman.[1] This testimony reviews the CGM Cost of Service ("COS") Methodology Review submission, filed with the Manitoba Public Utilities Board ("PUB" or "Board") on June 15, 2021 and related materials.

With respect to the testimony contained herein, Mr. Bowman notes the following:

- Mr. Bowman is an independent witness and his Resume is provided in Appendix A.
- Mr. Bowman's scope on this assignment was to review the Application taking into account normal regulatory principles for gas utility cost of service and relevance to eventual rate setting. The scope of review focuses particularly on matters of interest to large industrial gas users in Manitoba.
- Mr. Bowman acknowledges his role is to provide opinion evidence to the Board that is fair, objective and non-partisan.
- Mr. Bowman has endeavoured to ensure all factual assumptions and specific information relied upon are expressly cited in the testimony that follows.

This is the first CGM proceeding in which Mr. Bowman has participated. In the 2019/20 CGM General Rate Application ("GRA"), IGU submitted expert evidence from Mr. Andrew McLaren, which included brief comments on COS related to the scope today. Mr. Bowman has reviewed those comments and takes no issue with the submissions of Mr. McLaren. However, it is noted that the 2019/20 GRA specifically excluded consideration of COS methodologies, and as such Mr. Bowman recognizes Mr. McLaren's COS related comments are preliminary and general in nature.

This pre-filed testimony reviews the CGM submission, focused primarily on the work of Atrium Economics, LLC ("Atrium")[2], the independent expert retained by CGM to review CGM's COS methodology. Conclusions on the Atrium recommendations are provided in Section 2.

Beyond the Atrium recommendations, a series of additional comments are provided in Section 3 regarding further refinements and corrections that appear to be required in CGM's COS analysis.

[1] Services provided by Bowman Economic Consulting Inc.
[2] Application, Appendix 1

1.1 SUMMARY OF RECOMMENDATIONS

Based on the analysis summarized in this report, the following revisions to CGM's COS methodology are recommended:

Recommendation 1: Accept Atrium's recommendation to adopt a Coincident Peak allocation method.

Recommendation 2: Accept Atrium's recommendation to use design parameters for measuring coincident peak, rather than actual or historical average usage. The design parameters used should substantively reconcile to the design hour peak.

Recommendation 3: Accept Atrium's recommendation that the special contract customer be directly assigned only those assets directly linked to the service provided.

Recommendation 4: CGM should complete a Minimum System Study for the next GRA.

Recommendation 5: Allocation of contracted pipeline and storage capacity resources should be confirmed to follow one of two approaches, either the stack-based approach or the winter excess approach. The final determination of the approach to be used should be made at CGM's next GRA based on a comparison of whether the stack-based approach yields notably more refined cost allocation outcomes than the more simplified approach based on winter excess demand.

Recommendation 6: Atrium's principle that storage resources should be allocated based on winter usage has not been properly applied to TCPL-STS tolls, or to the Gas in Storage Rate Base working capital. These cost items should be corrected to be functionalized to STOR, classified to DEMAND, and allocated based on WINTEXC.

Recommendation 7: CGM should be directed to update the Transmission functionalization for assets and costs related to regulating, metering, communications and related services, to ensure those which function with a low side pressure below 1900 kPa (i.e., below Transmission pressures) are not functionalized to the Transmission function and not allocated to Mainline customers.

Recommendation 8: Distribution assets and related expenses tied to providing service to the distribution system (<1900 kPA) should not be allocated to the Mainline class of customers, who do not use this system, except through direct assignment if certain limited assets are dedicated to serving Mainline customers.

Recommendation 9: CGM's 2004 Unaccounted For Gas ("UFG") study requires updating to reflect current system UFG performance and loads. If UFG allocations are not provided specifically for each of the customer classes, the allocations must identify the vast majority of UFG which likely occurs on the distribution system, and ensure these costs are not recovered from transmission customers.

2.0 CENTRA GAS MANITOBA COS FILING

This section reviews the background on the CGM COS review and the Atrium report.

The CGM COS review is an outcome of the 2019/20 CGM GRA, Order 98/19, which stated that "all Cost of Service methodology and allocation issues"[3] be included in a generic Cost of Service proceeding.

In order to initiate the review, CGM retained independent expert advice, including a report, from Atrium Economics, LLC ("Atrium")[4].

This section reviews the CGM application and Atrium report recommendations, following a brief overview of key cost of service principles.

2.1 OVERVIEW OF RELEVANT COST OF SERVICE PRINCIPLES

Utility COS is a well-developed field with significant accepted principles and precedent. In general, the broad methodologies to be applied in COS analysis are not controversial, though specifics related to weighting different factual inputs and to implementation of methods can lead to differing conclusions.

It is important within a review of any utility's cost allocation methods to consider factual background of relevance to help determine appropriate methods and cost considerations. This can include but is not limited to general engineering and economic characteristics, framework for regulating the utility in terms of past practice, overall policy, materiality, and future planning and considerations as appropriate.

In general, it should be noted that the priorities for cost allocation in Manitoba have been recently established in the Manitoba Hydro COS review (2016) and the specific finding by the Board that:

> The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount.
>
> …Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the current use. [5]

This is consistent with the NARUC Gas Distribution Rate Design Manual, which provides that:

> Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs.[6]

In this regard, the "incurrence" of the costs would be read synonymous with cost causation.

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[3] Board Order 98/19 Revised, page 9.
[4] CGM Application, Appendix 1.
[5] Board Order 164-16, pages 27-28.
[6] National Association of Regulatory Utility Commissioners, Gas Distribution Rate Design Manual, page 20.

In regard to incurrence or causation, the principle to be applied is that customers should be allocated costs which they (or their class of customers) use, in proportion to the extent to which their use drives the cost in question, or drives the investment or spending that may become needed. Among the highest and best approaches to attributing costs to a customer or class of customers is direct measurement of costs incurred largely or solely for that customer or class of customers. As noted in the NARUC manual:

> All items that can be directly attributed to a particular service (such as revenues from a specific service or the cost of a high pressure main constructed for a particular customer or group of customers) should be segregated and directly assigned to the appropriate customers.[7]

Only for costs where causation or responsibility is shared do methods of allocation become necessary.

COS methods are also intended to be applied consistently over a period of time, until a change in method is justified. As such, methods adopted today could become a part of measuring each class' COS for years to come. This underlines a final relevant principle for adoption of COS methods for CGM in particular, which is the ability to understand and test the method despite CGM's preponderance of claims to confidentiality and commercially sensitive data. For most utilities, very little information is considered to be confidential or commercially sensitive in a valid regulatory proceeding, and of the information that is so declared, the vast majority is able to be shared with independent experts assisting affected customers. Proceedings involving CGM, however, do not share this degree of transparency. For this reason, COS methods and allocators should to the largest extent possible be based on clear and understandable methods that can either be confirmed and assessed without the use of confidential information, or can be generally tested by parties who are not privy to confidential information, with reliance on the Board and its advisors for the most limited set of cross-checks that can be accommodated. This approach will help mitigate the adverse impacts of CGM's propensity to avoid disclosure and oversight.

2.2 ATRIUM REPORT

The Request for Proposals that ultimately retained Atrium noted that the CGM "…objectives are to have Hydro retain an independent expert to assist in a review of Centra's Cost of Service Study Methodology, including the specific cost allocation concerns raised at the last GRA, outline alternative cost of service study options, recommend improvements and for the Consultant to assist throughout the Regulatory review to enable all necessary achievement of approvals."[8]

The Atrium report repeats these objectives at page 3 of their report, including:

> Specifically, the key objectives for Atrium are:
>
> A. Review of Centra's current COSS methodology, regulations, key issues of concern raised by participants in Centra's last general rate application.

[7] National Association of Regulatory Utility Commissioners, Gas Distribution Rate Design Manual, page 20.
[8] PUB MFR-1 pdf page 4.

Immediate concerns arise with this scoping of the Atrium assignment. First, the participants in CGM's last GRA were precluded from raising COS issues at the oral proceeding or argument phase by Order 98/19. As such, it is not apparent that the last GRA proceeding is a full and complete scoping of issues to be considered of importance to intervenors.

Second, the Atrium report was prepared with no consultation or involvement of interested customer groups. There are numerous examples of utilities who make significant use of customer consultation in scoping and/or resolving significant methodological issues as part of studies and cooperative or joint research occurring before a regulatory filing[9]. By failing to adopt this measure, it is not clear CGM has provided Atrium with appropriate and fulsome scoping.

Outside of issues with scoping, a review of the Atrium report indicates that on the matters Atrium did address, Atrium has provided a number of substantive and well-reasoned recommendations that are well-founded on industry practice.

The main Atrium recommendations are as follows:

1) Allocate Transmission and Distribution Plant Using a Coincident Peak Day Allocation Method
2) Demand Allocation Factors Should Use Design Day Peak
3) Directly Assign High Pressure Transmission to Customers
4) Refresh the Development of the Customer Component of Distribution Mains
5) Consider a Seasonal Resource Stack-Based Analysis for Allocation of Upstream Capacity Resources – Alternatively Use Winter Season Demand in Excess of Summer Season Demand.

This submission addresses each of the above recommendations.

2.2.1 Allocate Transmission and Distribution Plant Using a Coincident Peak Day Allocation Method

In respect of the first item, the use of a peak-related allocation method rather than the existing Peak and Average approach, this is a sound and well-reasoned approach reflecting cost causation. As a key example, it is noted that for capital-related cost drivers, the Winnipeg North West Project was among the largest capital additions in the previous decade (and by far the largest transmission mains plant addition, by a factor of 10[10]). This project was justified on the following basis:

> For the Phase I project: "the risk of not proceeding with this upgrade is a loss of reliable gas supply to our natural gas customers on the Winnipeg NW MP network under peak flow conditions during cold weather."[11]
>
> For the Phase 2 project: "the extension of an existing natural gas pipeline from the Rosser Station (GS-031) in Winnipeg to the City of Selkirk (GS-004) is necessary

[9] For example, see BC Hydro 2015 Rate Design Application, Chapter 3 Cost of Service Methodology, and Appendix C Consultation. British Columbia Utilities Commission Project 3698781
[10] IGU\Centra I-5b from the 2019/20 GRA.
[11] PUB/Centra I-73 Attachment from the 2019/20 GRA, page 36 of 370

> to provide additional capacity to the areas northwest of Winnipeg and to provide a redundant gas source to meet reliability and operational requirements in the Winnipeg natural gas transmission network" and "The requirement to correct high velocities in the Stonewall transmission branch and provide capacity in the area northwest of Winnipeg require modifications to the transmission system to provide new supply while maintaining system reliability."[12]

The project description is consistent with the primary project driver for cost causation purposes being the capacity and reliability of the system focused on times of peak usage. The example underlines the reason transmission capacity is well-suited to a peak demand allocation.

It is also important to note that the existing Peak and Average approach is, on occasion, used in the allocation of gas utility costs, where facts differ from CGM's. In particular, the situations in which it is used are typically different than the gas distribution nature of CGM's operation. Atrium gives one such example in response to CAC/Atrium I-2f, where a gas utility is described as having multiple trading points, and costs that must be allocated between both sales and transportation customers (a feature that CGM does not have). Atrium indicates the system in question has seven interconnected interstate pipelines which do not have points of delivery sized in relation to the utility peak day. In short, it would appear that Atrium relies at least in part on the fact that the system is not designed and/or sized primarily for reliable service during a winter peak, unlike CGM. For this reason, it appears no direct comparison is possible between that case and CGM.

CGM has also previously suggested that the Peak and Average approach is necessary due to the interruptible class, which would not necessarily be allocated any costs under a peak day approach based on usage. However, this is no longer an issue, as described by CGM at page 30 of the Application, and is particularly not an issue under the peak design day approach. It is also important to note that the relevance of CGM's interruptible class as a driver for cost allocation is of diminished importance as the class declines in size[13], and in recognition that the class has not actually been interrupted for downstream-related reasons for over 20 years[14]. As such, these loads can readily be incorporated into cost allocation based on a coincident peak methodology.

Finally, it is noted that the response to PUB/Centra I-9(c) highlights the specific situation of off-season loads (such as grain dryers) and how these loads would play into calculations of coincident peak demand levels. The response indicates that "to the extent that seasonal loads do not contribute to the historical coincident peak demand of the class, their loads is effectively not included in the determination of their class coincident peak demand."[15] This response does not fully explore the extant issue. There is no class in the COS study specifically for grain dryers or other off-peak loads. These loads are part of a class for which there is variability and diversity, and they would pay rates consistent with the class. The loads in question would not receive no allocation of peak demand costs – they would receive the same allocation of peak demand costs shared among their class. This is no different than residential customers which snowbird for the

[12] PUB/Centra I-73 Attachment from the 2019/20 GRA, page 56-60 of 370
[13] For example, see CAC/Centra I-24(b) from the 2019/20 GRA.
[14] PUB/Centra I-10(b).
[15] PUB/Centra I-9(c)

winter, as an example. Every utility, gas or electric, which uses classes for cost allocation will have similar load diversity among each class, be it daily peaks (e.g., for people who work nights) or seasonal (such as the seasonal businesses described). The appropriate way to deal with this unavoidable form of load diversity within a class is through rate design, not through changing COS methods which are otherwise founded in cost causation. Consider the case of Manitoba Hydro. For off-peak and low load factor users there is a rate offering which provides a more appropriate rate known as the Limited Use of Billing Demand ("LUBD") option. The existence of this rate is of no consequence when designing classes for the purposes of COS analysis, much less when choosing the appropriate cost allocation approach.

For all of the above reasons, it appears Atrium's recommendation to use a Coincident Peak allocator is well-founded and appropriate, and should be adopted by the Board.

> **Recommendation 1: Accept Atrium's recommendation to adopt a Coincident Peak allocation method.**

2.2.2 Demand Allocation Factors Should Use Design Day Peak

In regard to Atrium's second recommendation (use of a design day measure rather than a usage-based measure of the peak), this is consistent with the principles of COS being tied to the reasons the costs were incurred. CGM's planning is based on a peak design hour[16], used in hydraulic modelling. This type of design criteria emphasizes that capital investments are driven by the intended design capacity of the system, not just the particular usage in a given year (or series of years) which could reflect anomalous weather or other usage patterns.

CGM indicates that it intends to develop a design day allocator to determine class contributions under a weather normalized model[17]. This is an appropriate first step in implementing the Atrium recommendation and moving to recognition of design-related cost drivers.

However, CGM's description of the development of the allocator indicates that it will "be developed in conjunction with the approved load forecast"[18]. While the load forecast should be one input to the peak design day allocation, it is important that the allocator reflect the actual risk-adjusted peak load that CGM considers necessary for system planning and investment. For example, if CGM uses inputs to the design process that include safety margins on temperature, customer coincidence, or load forecast risk, these variables should be part of the allocator. Ultimately, the coincident peak design day allocator should largely reconcile to the design hour actually used by CGM's planning staff, and not necessarily to the load forecast that happens to be used in any given GRA.

> **Recommendation 2: Accept Atrium's recommendation to use design parameters for measuring coincident peak, rather than actual or historical average usage. The design parameters used should substantively reconcile to the design hour peak.**

[16] Application page 30-31
[17] PUB/Centra I-9(a)
[18] PUB/Centra I-9(d)

2.2.3 Directly Assign High Pressure Transmission to Customers

Atrium's third recommendation is to directly assign high pressure transmission plant to customers where appropriate, and provide no other allocation of the broader transmission system. This is referenced in regard to the Special Contract customer as well as the Power Stations class. As noted above, this type of approach is entirely consistent with COS principles outlined in the NARUC Gas Distribution manual, and with the concept of customers paying for cost incurrence.

Direct assignment is a well-established approach utilized in COS, and best matches the idea that customers should pay for assets they use, and not pay for assets they do not use. The establishment of customer classes and different service levels (e.g., high pressure, low pressure) is a subsidiary methodology to revert to allocation where direct assignment is not possible. But direct assignment of costs is a preferred method that increases fairness where the assets or costs can be directly linked to a user or class.

In the case of the Special Contract customer, direct assignment is not only possible, but also clearly rational as a means to allocate costs, as described in Atrium's report section 5.2.1.[19] Indeed, the example represents a near-perfect case of direct cost incurrence, to the exclusion of other costs on the system. As noted by Atrium: "It is entirely appropriate to directly assign the cost responsibility for these pipeline facilities to the customer when a nexus between the cost incurrence and the customer can be identified."[20] This nexus exists for the Special Contract customer in respect of assets that are used almost entirely, if not solely, by the customer, while other transmission assets in the system are not used to any degree whatsoever by the customer.

In the event a direct allocation of costs in the COS study is not implemented, the alternative precedent is set out for the case of FortisBC, as described by Atrium in CAC/Atrium I-6(b). Under that approach, the customer is not directly allocated costs via the cost of service study, and does not form a "class" in the COS analysis. Instead rates for the unique special contract are established outside the Cost of Service study, and then when the COS study is modelled, the revenues received from the special contract are considered an offset to the costs otherwise included in the COS. Mathematically, the approach would be akin to the treatment of export revenue in the Manitoba Hydro electricity COS study, where the sales are not reported as being part of any "class" (there is no export class in the MH electricity COS study), but instead are reflected only as a revenue which is credited against the overall costs that the utility incurs[21]. Using such an approach would not remove the need for a regulated rate to be developed to serve the Special Contract customer, but that rate could in theory become a direct calculation based solely on assets used by the customer. On balance, the approach proposed by Atrium is preferable, but the export-styled approach would be a more preferable alternative than the status quo, where the service to the Special Contract customer includes excessive assets that can be shown to bear no linkage to the service provided the customer.

[19] Application, Appendix 1, page 16-17
[20] Application, Appendix 1, page 17
[21] See Board Order 164/16 page 9-10

Recommendation 3: Accept Atrium's recommendation that the special contract customer be directly assigned only those assets directly linked to the service provided.

2.2.4 Refresh the Development of the Customer Component of Distribution Mains

Atrium's fourth recommendation is to update the distribution system classification between the capacity and customer classifications. This type of allocation is a normal update undertaken as part of COS reviews, including potentially as a periodic part of a GRA. CGM indicates that the data required for a zero-intercept study is not presently available.[22] It is also noted that data limitations can also at times restrict the ability to conduct a defensible minimum system study, as was the case for EPCOR's electrical operations in Alberta.[23] Nonetheless, EPCOR completed the study to the best of its ability and brought forward the conclusions along with a recommendation that the results not be used due to limitations that were outlined and detailed.[24] The AUC is still reviewing this recommendation. However, this approach of bringing forward transparent data and permitting public deliberations reflects a thoughtful and cooperative basis for customer input. CGM should be encouraged to do the same with respect to CGM's distribution classification analyses.

It is also noted that the conceptual basis for a Minimum System Study is more sound than a Zero Intercept study, as a minimum system is a concept for a functioning gas distribution entity, while zero intercept is a purely theoretical concept. CGM dismisses its ability to complete a zero-intercept study, but does not appear to reject the ability to complete a minimum system study in the Application proper. Atrium also recommends that a Minimum System Study be conducted in the absence of a zero intercept study[25].

In general, the issue of distribution classification is of relatively less relevance to the largest system users, who do not contribute to distribution system loads. However, a portion of the distribution mains are allocated to large users in the High Volume Firm class. It is appropriate for customers in this class to expect that the classification to demand and customer should be routinely considered and refreshed.

Recommendation 4: CGM should complete a Minimum System Study for the next GRA.

2.2.5 Consider a Seasonal Resource Stack-Based Analysis for Allocation of Upstream Capacity Resources – Alternatively Use Winter Season Demand in Excess of Summer Season Demand.

The final set of recommendations from Atrium relate to upstream capacity resources. Atrium provides a recommendation that these upstream contracted pipeline and storage capacity resources should be allocated using a "seasonal resource stack-based analysis of each pipeline and

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[22] Application, page 34.
[23] For example, in the electricity Cost of Service study for EPCOR Distribution and Transmission Inc., Alberta Utilities Commission proceeding 27018, Black and Veatch was unable to complete a reliable Minimum System study due to data limitations.
[24] See AUC Exhibit 27018-X0002 pdf page 19.
[25] PUB/Atrium I-13.

storage capacity resource's contribution to the seasonal and peak day demands"[26] of customers. Alternatively, Atrium recommends use of winter season demand in excess of summer season demand. Both methods are consistent with the concept that storage requirements arise due to variations in a customer's (and the overall system's) seasonal load, and costs incurred for this purpose should track that seasonal load contribution. A customer or customer class whose load was perfectly flat, meaning their winter demand matched their summer demand, would not require any material storage and their load requirements would be met by "flowing gas supply using year-round pipeline capacity".[27] As noted by CGM's expert in the 1996 COS review:

> Storage costs are incurred solely to meet winter seasonal requirements.[28]

The primary Atrium recommendation appears to target specific apportionment of costs to different periods during the year based on effectively two factors:

1) The different loads imposed on the system by customer usage throughout the year
2) The different resource costs to supply the system and meet customer needs at the different times of year.

In short, the Atrium proposals appear to target fairness by ensuring not only that customers who drive high winter peaks pay a larger share of annual supply costs, but also that to the extent these high winter peaks are priced at a premium cost, these premiums are recovered from the customers who drove the underlying seasonal peaks.

The alternative approach identified by Atrium appears to therefore be an inferior approach in terms of fairness and tracking cost causation, in that it only appears to track the first of the two factors noted above – that is the method would assign more of annual cost to customer classes whose loads peak in winter, but it would not assign the premium prices associated with serving those loads to the customers who drive the peaks. The alternative approach is also inferior in that it is a measure of average usage over four winter months, as compared to the average usage over the remaining eight months[29]. In order to meet acute system needs on key supply days, which are disproportionately driven by only certain customer classes, added costs must be incurred for pipeline capacity. A measure of average usage over 4 months will fail to capture this more acute cost driver. As such, the alternative is at best a coarse approximation of the costs driven by differentiated seasonal use.

At the same time, it is understood that the input data for the seasonal resource stack-based approach recommended by Atrium would track the detailed mix and costs of resources CGM acquires to meet the seasonal variations in customer loads. This includes multiple forms of pipeline contracts and storage capacity. The underlying data to complete this analysis would include

[26] Application, Appendix 1, page 31.
[27] PUB/Atrium I-10(a)
[28] PUB MFR-7 Attachment pdf page 51 of 102
[29] See PUB/Centra I-8(d).

significant quantities of confidential information under CGM's proposed approach to information transparency[30].

For the above reasons, in the absence of information about the materiality of the difference, it is difficult to determine the approach to recommend. If the difference in cost allocation percentages between a stack-based approach and a winter excess demand approach are not material, simplicity and minimizing the need for confidential information would lead to a preference for the winter excess demand approach. However, a simplification of this type which undermines cost causation in any material way cannot be recommended. In this case, the stack-based approach should be used.

Unfortunately, in the absence of quantitative assessments, it is not possible to determine the appropriate approach. The Board should confirm that one of the two noted approaches will be adopted as part of the next CGM GRA. CGM should be directed to prepare an analysis using both approaches, and any other refinements that meet the underlying cost tracking objective, to determine whether a material improvement in accuracy is provided by adopting the more detailed and complicated approach of stack-based allocation. A final decision on the recommended approach can be made at that time.

> **Recommendation 5: Allocation of contracted pipeline and storage capacity resources should be confirmed to follow one of two approaches, either the stack-based approach or the winter excess approach. The final determination of the approach to be used should be made at CGM's next GRA based on a comparison of whether the stack-based approach yields notably more refined cost allocation outcomes than the more simplified approach based on winter excess demand.**

One clear issue with the implementation of the Atrium recommendation regarding pipeline capacity and storage capacity costs is that CGM has not extended the principle to costs that vary with the same underlying cost drivers. There are 2 noted examples in the evidence filed:

- First, the costs incurred for TCPL-STS (Storage Transportation Service), which is a cost incurred to ship gas related to storage injection. This cost is highlighted in PUB/Centra I-15.
- Second, the costs related to Rate Base (net investment in working capital/inventory) related to gas in storage, which is addressed at IGU/Centra I-2(k).

In each case above, the costs in question are driven primarily, if not entirely, by the need to provide storage services to meet seasonal peaks. As such, the cost driver related to the incurrence of the cost is winter usage, consistent with the winter excess demand allocation approach.

With respect to TCPL-STS, CGM notes in response to PUB/Centra I-15 that the costs are related to storage, and as such this cost "should be allocated consistent with other storage-related

[30] Centra May 16, 2022 letter to the PUB outlining confidentiality claims related to, among other things: "Details of Centra's gas supply portfolio (i.e., all non-public commercial arrangements including contract details and Capacity Management transactions), including costs (except at summary levels)"

transportation using the Winter Season Demand in Excess of Summer Season Demand".[31] Despite this admission, the response to other interrogatories indicate CGM is not presently implementing this approach. Specifically, the CGM update to Appendix 3[32] indicates the costs of TCPL-STS are proposed to be functionalized to PIPE, classified to DEMAND, and allocated based on PDAY(INT), which is not consistent with the response to PUB/Centra I-15 (the correct approach should be functionalized to STOR, classified to DEMAND, and allocated based on WINTEXC). The values related to this item are also expected to be sufficiently material as to merit correction (in the last non-redacted COS, from 2013/14 GRA[33], the costs exceeded $2 million). As such, CGM should be directed to ensure this allocation is implemented.

On the matter of Gas in Storage Rate Base, in the response to IGU/Centra I-2(k) indicates the COM1 allocator is used[34], which is the allocator for total system sales excluding T-service customers. CGM asserts that the Gas in Storage Rate Base related cost (the interest and return on the cash outlays to finance gas in storage) "relates to the financial cost to the utility of holding Primary and Supplemental Gas inventory throughout the year. This cost is driven by the energy requirements of all sales system customers."[35] As noted above, the need for storage (and the need to keep cash invested in gas in storage) is not driven by a generic measure of customer volume. The need for storage is driven by customer usage patterns that expect gas delivery volumes in winter in excess of gas delivery volumes in the remainder of the year. For this reason, Gas in Storage is clearly a storage-related cost, and should be allocated consistent with all other storage related costs. The cost is currently functionalized to STOR, classified to ENERGY, and allocated based on COM1, which is incorrect. The correct approach should be functionalized to STOR, classified to DEMAND, and allocated based on WINTEXC. As indicated in CGM's interrogatory responses[36], the balance of Rate Base related to Gas in Storage is material, at $53,559,521. CGM should be directed to implement this allocation in their final COS methods from this review.

Recommendation 6: Atrium's principle that storage resources should be allocated based on winter usage has not been properly applied to TCPL-STS tolls, or to the Gas in Storage Rate Base working capital. These cost items should be corrected to be functionalized to STOR, classified to DEMAND, and allocated based on WINTEXC.

[31] PUB/Centra I-15.
[32] IGU/Centra I-2(b) Attachment 1 page 22 of 32
[33] Centra 2013/14 GRA Schedule 11.1.5, page 1 of 6
[34] Also see IGU/Centra I-2(b) Attachment 1 page 17 of 32, reflecting the proposed methodology.
[35] IGU/Centra I-2(k).
[36] IGU/Centra I-1(c) Attachment 1, page 20 of 28.

3.0 OTHER MATTERS

3.1 CUSTOMER CLASS DESIGN AND DISTRIBUTION SYSTEM ALLOCATION

The design of classes for the purposes of cost allocation is a key step in determining whether a COS will yield fair results. In the case of larger customers, it is necessary to consider which customers participate in, and drive the costs of, each component of the system. In particular, lower pressure and smaller volume components of the system are of no relevance to service to large customers, and as such should not be allocated to these customers. This principle has been recognized by Atrium in their recommendation to directly allocate only a certain subset of assets to the Special Contract and Power Station classes, and to remove from those classes responsibility for assets that are too small, or in the wrong part of the province, or of no relevance to their operations (e.g., odourization).

In an ideal model, CGM would be able to track assets, costs and loads by tiers of usage, similar to that used by Manitoba Hydro with respect to the General Service Large subclasses (e.g., >100 kV, 30-100 kV and 0-30 kV). In some jurisdictions, gas transmission (>700 kPa) is owned separately from distribution (700 kPa or less) such that for transmission served customers, there is assurance that they are not allocated costs of the low pressure distribution system (since it makes up no part of the transmission utility's revenue requirement). In CGM's case, this is not the corporate structure, as transmission, intermediate and distribution assets are all owned by the same entity and included in a single revenue requirement.

Long-term refinement of CGM's COS to distinguish loads served only from the intermediate pressure assets, versus those served from the low pressure assets would likely be an advisable evolution. At this time, it does not appear to be an achievable outcome given CGM's statements about its accounting information, such as in IGU/Centra I-3(f), and customer structure, which largely focuses on annual volumes rather than pressures to determine smaller versus larger customers, per IGU/Centra I-3(e).

Outside of distinguishing low versus intermediate uses, a key issue of concern today is appropriate allocation to the largest users – Mainline customers. This group of customers is defined as follows:

> Mainline Customers receive gas through one meter where the Customer is served directly from the Company's transmission system or through dedicated distribution facilities at pressures in excess of medium pressure.[37]

As noted in the 1986 Cost of Service review when the Mainline Firm class was being created, the key is to develop a group of customers for whom assets can be dedicated and tracked to the class, comprising only the largest capacities:

> In order to make the rate cost-reflective, and applicable to the specific situation of these handful of customers, it is necessary to restrict" the class to those customers

[37] Application Appendix 2, page 4.

that are clearly served directly and exclusively from the transmission system through dedicated or strictly identifiable facilities.[38]

For these customers, many of CGM's functions are of little to no relevance.

For example, in the case of such items as measuring and regulating equipment, it must be understood that this is one component of the service CGM provides to customers. There is a cost of investment, maintenance and operations to own and deliver this service. Customers who are served at a high pressure do not make as much use of the service as customers who receive service at lower pressures. The most notable example is Mainline customers, who are limited to receiving service from Transmission (1900 kPa or above, or using dedicated facilities to connect to Transmission).

An appropriate COS functionalization would seek to divide the related revenue requirements for Measuring and Regulating Equipment (account 467 and 477) and related operating costs (e.g. Regulating Station Maintenance) to most accurately track which stations contribute to service to which classes. It appears CGM's COS does not at present track this appropriately.

There are two issues with CGM's functionalization and allocation in this regard:

1) **Assets that should not be functionalized as Transmission:** in response to PUB/Centra I-1 the Board explores whether stations that step down pressures to below 1900 kPa are functionalized as Distribution. CGM indicates it does have stations that reduce pressures to below 1900 kPa that it considers Transmission. CGM explains that this is because its accounting records consider these stations as transmission based on the high side pressures (TCPL Mainline) and the existence of customer transfer flow metering, odourization and SCADA communications for monitoring[39] which are typical transmission type of assets. However, there is no relevance of these assets to providing service to Mainline customer, who receive service at above 1900 kPa or through dedicated facilities, if indeed the existence of these assets is solely to provide service below 1900 kPa.

2) **Assets functionalized as Distribution being allocated to Mainline customers:** In addition to the issue of assets that are being functionalized as Transmission when they should be Distribution, CGM also takes assets and costs functionalized as Distribution and allocates these assets and costs to customers who do not use gas at distribution pressures. For cost allocation purposes, CGM's Distribution function should include assets and costs relevant to providing service to customers who do not qualify for Mainline status (i.e., served at 1900 kPa or served by dedicated facilities that connect to the transmission system, the costs of which should be specifically assigned to the class).

With respect to assets to be functionalized as Transmission for COS purposes (the first item above), the key defining feature must be the low side pressures, not the high side. If an asset or station is serving to reduce pressures to below 1900 kPa, for service on CGM's intermediate pressure system or below, it should not be functionalized as part of CGM's Transmission system for COS

[38] MFR 7 Attachment pdf page 17 of 102.
[39] PUB/Centra I-1

purposes. This is true of all regulating, metering, communication, or other infrastructure or costs associated with stations of this type. It is not clear that a quantification has been provided for what quantity of assets may qualify for this revision, though at minimum it would include those highlighted in the response to PUB/Centra I-1. Other gate stations and town border stations would require similar analysis to determine the needed corrections to functionalization.

For those costs functionalized as Distribution, the definition of the account codes is provided in IGU/Centra I-7a-c Attachment 1. In this attachment, Distribution Plant is clearly indicated to include "Pipelines with operating pressures less than or equal to 1900 kPa, all pressure reducing stations downstream of transmission station plant, all farm taps and farm tap inlet piping and all associated pipeline vales, fittings, service lines and customer meter set assemblies."[40] Outside of possibly "customer meter set assemblies" (if these include customer meters used by Mainline customers), the assets in question are clearly related to and used in providing service to customers who take service below the Mainline class eligibility. For example, account 477 Station Metering and Regulating Equipment relates to "the cost of meters, gauges, regulators and associated equipment used for measuring gas or distribution operations."[41] As described, these assets are not part of providing transmission service to Mainline customers. The same considerations arise for other distribution asset groups. Despite this lack of relevance to Mainline customers, CGM describes that the costs of Account 477 are allocated using PAVG-TBS which includes all customer loads other than Special Contract and Power Station classes[42].

CGM then confuses the description of Account 477 in PUB/Centra I-6 where it notes the costs of facilities dedicated to Mainline customers are included in Distribution M&R (Account 477). Not only is this distribution account code an inappropriate account code for assets serving transmission-related customers, but it is also not apparent that CGM actually tracks and dedicates the costs of any infrastructure related to Mainline customers to the Mainline class. Instead, the Mainline class appears to receive simply an allocation of all distribution-related account 477 assets, which is not appropriate and would serve to inflate costs allocated to Mainline customers.

CGM has indicated that scale of distribution assets that are included in Mainline cost allocation is material[43], at over $60 million[44] in gross plant, while the corresponding scale of related operating and maintenance costs is not provided due to redactions[45]. This allocation to Mainline customers should be eliminated, unless a direct causal link can be shown, and in that case, costs should be directly assigned to the class.

> **Recommendation 7: CGM should be directed to update the Transmission functionalization for assets and costs related to regulating, metering, communications and related services, to ensure those which function with a low**

[40] IGU/Centra I-7a-c Attachment 2, page 2 of 10.
[41] IGU/Centra I-7a-c Attachment 2, page 3 of 10.
[42] PUB/Centra I-6, page 2
[43] IGU/Centra I-1c Attachment 1, page 23 of 28.
[44] This includes accounts 470, 471, 472.1, 477, and 477.1. Per IGU/Centra I-7(c) the list may include as much as $3 million in costs.
[45] In 2013/14, the O&M expense for Station Maintenance approached $6 million, per PUB/Centra I-19(b) Attachment 2 page 12 of 15.

> **side pressure below 1900 kPa (i.e., below Transmission pressures) are not functionalized to the Transmission function and not allocated to Mainline customers.**
>
> **Recommendation 8: Distribution assets and related expenses tied to providing service to the distribution system (<1900 kPA) should not be allocated to the Mainline class of customers, who do not use this system, except through direct assignment if certain limited assets are dedicated to serving Mainline customers.**

In addition, it is not clear that the opportunity to take service as a Mainline customer is fully enabled by the specific wording setting out the Mainline customer eligibility. In general, the definitions for eligibility as a Mainline customer was exceedingly narrow, as follows:

> Centra has determined that the Main Line class should have very restrictive eligibility requirements. In order to make the rate cost-reflective, and applicable to the specific situation of these handful of customers, it is necessary to restrict the class to those customers that are clearly served directly and exclusively from the transmission system through dedicated or strictly identifiable facilities. For those customers that "almost" qualify for Main Line, or who feel that they would qualify for Main Line service. but for Centra's decision to attach them in a different manner, the option to sign a Special Contract is still available. [46]

The particular situations intended to be captured by the “almost” language are not clear, but CGM’s responses appear to suggest a limited interest in aiding availability of the Mainline designation, noting:

> Any customer with less than average costs to serve would prefer to have an individual rate that uniquely reflects their specific costs, including the specific cost of any dedicated plant such as meters and service-lines, but such an approach is not justifiable or administratively feasible.[47]

The availability of the Mainline designation should be freely available to any customer who is appropriately served entirely, or almost entirely, from transmission assets. If only a dedicated segment of infrastructure separates a customer from transmission level service (as illustrated in the Atrium report, Appendix A), and the customer is of a scale and magnitude that otherwise indicates a transmission level service is appropriate, eligibility should be permitted. If there are customers who are disadvantaged by their status as “almost” qualifying, as described in the 1996 report, CGM should work with the customer to resolve the issue and recourse should be available to the Board to address disputes. This principle is not specifically a COS related matter, so is not included in the summary of recommendations from this submission, but in the event there is any concerns with this manner of implementing customer access to the Mainline class using this approach, it should be explored and clarified with the Board as part of CGM’s current or subsequent proceeding.

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[46] MFR 7 Attachment pdf page 17 of 102.
[47] IGU/Centra I-8(a).

3.2 UNACCOUNTED FOR GAS

In their original report, Atrium does not address in any detail the issue of Unaccounted For Gas ("UFG"), which comprises all sources of gas that are measured as delivered to CGM, but not measured as sold to customers.

However, in interrogatories, Atrium indicated that they had revisited the topic and now recommend that the UFG matter be subjected to an updated study to establish the system-wide level of UFG[48].

The current allocation of UFG comes from a study completed in 2004, as amended by the Board in Order 131/04 (to lower the allocation to the Special Contract customer). The study was provided in MFR 10. CGM repeatedly references the use of allocation ratios arising from Order 131/04, which were prescribed by the Board for that proceeding, but fails to note that the Order in question indicated "The Board encourages CGM to continue its review of UFG, and consult with other interested parties."[49]

While quantification of the allocation ratio in the current study appears to have not been provided due to CGM redactions, it is understood that the 2004 study (as amended in Order 131/04) remains the basis for allocation. CGM specifically noted in the 2013/14 GRA that it had not updated the study[50] and still references the study as the rationale for the allocator[51].

The continued use of a 20 year old study, which CGM was encouraged to update but did not, is additionally problematic by way of the clear changes in the system. For one - the relative load balance between the various classes change over this period. It appears that notwithstanding changes in the relative balance of loads and customers, CGM has not updated the percentages in any way. Second, the degree of UFG that is present in the system appears to have declined markedly. For example, in the 2004 study, CGM cites that the UFG approximates 1%[52] of receipts. However, as of the more recent GRAs, the following UFG percentages have been cited:

[48] PUB/Atrium I-8a-b
[49] Order 131/04, page 39.
[50] PUB/Centra I-135 from the 2013/14 GRA.
[51] IGU/Centra I-6(a)
[52] PUB MFR-10 page 1 of 14.

2013/14 GRA – PUB/Centra I-99(b)

2007/08 – 0.68%

2008/09 – 1.35%

2009/10 – 0.73%

2010/11 – 1.01%

2011/12 – 0.52%

2019/20 GRA – PUB/Centra I-120

2012/13 – 0.53%

2013/14 – 1.00%

2014/15 – 0.67%

2015/16 – 0.24%

2016/17 – 0.58%

2017/18 – 0.56%

The above UFG percentages average 0.86% over the period reported in the 2013/14 GRA, and 0.6% in the period reported in the 2019/20 GRA. In short, a study based on allocating UFG from a period where the losses averaged 1% of receipts is clearly dated.

In terms of approach to updating the study, CGM's previous approach was to allocate the UFG percentages to each of the customer classes. It appears this approach may under-recognize the different characteristics of the distribution and transmission systems, and the much greater UFG that is expected to arise on the distribution system and for customers connected to the distribution system. For example, such items as theft or seized meters, factors that can be present and go unnoticed for a time on distribution systems, are not a factor on transmission systems. On a transmission system there is simply less quantity of conveyances to leak, less points to be affected by outside factors like auto collisions, less places for bad meters to arise. Atrium submits that "establishing a class-level allocation is unnecessary."[53] This is generally true, but in the alternative establishing a distinct allocation of UFG associated with customers who make extensive use of the distribution system, versus customer who mainly or solely make use of the transmission system, is necessary to achieve accuracy and fairness.

> **Recommendation 9: CGM's 2004 Unaccounted For Gas ("UFG") study requires updating to reflect current system UFG performance and loads. If UFG allocations are not provided specifically for each of the customer classes, the allocations must identify the vast majority of UFG which likely occurs on the distribution system, and ensure these costs are not recovered from transmission customers.**

[53] PUB/Atrium I-8(a).

APPENDIX A: Resume

PATRICK BOWMAN

Principal Consultant
Bowman Economic Consulting Inc.

161 Rue Hebert
Winnipeg, Manitoba
R2H 0A5 CANADA

AREAS OF EXPERIENCE:

- Utility Regulation and Rates
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

Bowman Economic Consulting Inc., Winnipeg, Manitoba

2020 – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation.

InterGroup Consultants Ltd., Winnipeg, Manitoba

1998 – 2020 – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability. Major clients included the following:

- **For Manitoba Industrial Power Users Group (1998 – 2020):** Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, depreciation, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (Centra Gas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.
- **For Northwest Territories Power Corporation (2000 - 2020):** Provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings, major capital developments and utility acquisition and valuation topics. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).
- **For Industrial Customers of Newfoundland and Labrador Hydro (2001 – 2020):** Prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities, depreciation, rate mitigation for major new capital spending. Appear before PUB as expert in cost of service and rate design matters.

- **For Nelson Hydro (2013 - 2020):** Development and updating of a Cost of Service model and filings before the BCUC.
- **For City of Chestermere (2015 – 2020):** Analysis of rate proposals from Chestermere Utilities Inc. and review of strategic options for utility.
- **For the Office of the Utilities Consumer Advocate of Alberta (2016 – 2020):** Provide expert witness and strategic support of multiple depreciation and revenue requirement proceedings. This includes ongoing participation in depreciation working group discussions on behalf of the UCA.
- **For the Association of Major Power Consumers of British Columbia (2015 – 2020):** Provide expert advice in the current 2020-2021 Revenue Requirement Application with a focus on general service large and transmission service customers. Provide consulting support regarding transmission service customer and rate design issues in the 2015 Rate Design Application.
- **Vancouver Airport Fuel Facilities Corporation (2019 – 2020):** Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence.
- **Jamaica Public Service (2019):** Assist in preparation of regulatory documents, Executive Summary, review of strategic issues for General Rate Application.
- **For Hualapai Tribal Utility Authority (2017 - 2018):** Provided strategic advice to the HTUA Board, and completion of a feasibility study and Cost of Service analysis for the acquisition of assets and development of a tribally-owned distribution utility, including power purchase and transmission, asset purchase (acquisition value) and replacement costs, and ongoing operation and maintenance costs. The assignment included a review of comparable jurisdiction cost and rate structures, building a financial model with input cost variables, reporting and presenting in HTUA Board meetings.
- **For Yukon Energy Corporation (1998 - 2014):** Provided analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appeared before YUB as expert on revenue requirement matters, depreciation, cost of service, rate design, and resource planning. Prepared analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers. Analysis and support regarding utility asset transfer and system rationalization among various utilities.
- **For City of Swift Current (2013 - 2014):** Utility system valuation for acquisition and disposition alternatives assessment.
- **For Municipal Customers of City of Calgary Water Utility (2012 - 2017):** Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).
- **For Yukon Development Corporation (1998 - 2012):** Prepared analysis and submission on energy matters to Government. Participated in development of options for government rate subsidy programs. Assisted with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.
- **For NorthWest Company Ltd. (2004 - 2006):** Reviewed rate and rider applications by Nunavut Power Corporation (Qulliq Energy). Provided analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio- economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005 - 2014):** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.
- **For Northwest Territories Power Corporation (2010 - 2012):** Participated in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provided economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions.
- **For Northwest Territories Energy Corporation (2003 - 2005):** Provided analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.
- **For Kwadacha First Nation and Tsay Keh Dene (2002 - 2004):** Supported and analysed potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Reviewed options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.
- **For Manitoba Hydro Power Major Projects Planning Department (1999 - 2002):** Initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participation in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).
- **For Manitoba Hydro Mitigation Department (1999 - 2002):** Provided analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program.
- **For International Joint Commission (1998):** Analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.
- **For Nelson River Sturgeon Co-Management Board (1998 and 2005):** An assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of Northwest Territories, Yellowknife, Northwest Territories

1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Evidence and Negotiated Settlement	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlement
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlement
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - present	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018 - present	Yes
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coaliation	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence TBD	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to information requests.	NWT PUB	NTPC	2022	TBD
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	TBD

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