Centra Gas Manitoba Cost of Service Methodology Review - Written Submission of IGU

The Board convened the current Cost of Service (COS) methodology review as part of Order 98/19, which deferred “all cost of service methodology and allocation issues” to a later proceeding. Centra Gas Manitoba (CGM or Centra) initiated the current proceeding with the retention of Atrium Economics, LLC (Atrium), who was to provide independent expert advice, including a report (now filed as Centra Application, Appendix 1).

Fundamentally, there are two broad questions before the Board in this proceeding:

1) Whether to accept the Atrium recommendations, in whole or in part?
2) Whether other matters require adjustment or further investigation beyond those addressed by Atrium?

This submission addresses both areas in sequence, under the following headings:

- IGU Intervention
- Hearing Scope
- Atrium Recommendations
    - Coincident Peak Day Allocation Method
    - Centra’s Design Peak
    - Direct Allocation to the Special Contract Customer
    - Allocation of Upstream Capacity Resources
- Matters outside the Original Atrium Recommendations
    - Demand Side Management
    - Storage Costs in Rate Base
    - Unaccounted For Gas
    - Mainline Firm Cost Allocation Principles
    - Special Contract Customer Rate Adjustment

IGU INTERVENTION

The Industrial Gas Users (IGU) intervention in this COS methodology proceeding represents a collaborative effort of participants in the Special Contract, Mainline and High-Volume Firm classes, who individually and collectively are substantial natural gas users. The IGU companies participating in this intervention include Koch Fertilizer Canada (chemical), Gerdau Long Steel North America Manitoba Mill (steel), Simplot Canada (II) Limited (food processing), Roquette Canada (food processing), and Maple Leaf Foods (food processing).

As high-volume industrial users, with similar usage characteristics as other industrial users within these classes, IGU’s submissions reflect the broad interests and priorities of high-volume users in the Special Contract, Mainline, and High-Volume Firm classes. While the majority of these IGU participants and related larger users are Transportation Service (T-Service) customers, responsible for procurement and transportation of their natural gas volumes to Manitoba for delivery to the CGM transmission and distribution system, some of the load represented within the IGU classes is served as Sales Service customers. Collectively, IGU represents the larger industrial users in Manitoba, seeking fair and reasonable, cost-based rates for their use of the CGM transmission and distribution system.

IGU members strongly support ratemaking that is cost-based, which highlights the importance of their intervention in this COSS proceeding. Since IGU members are primarily T-Service customers, their intervention is primarily aligned (but not limited to) the allocation of non-gas costs related to the design, planning and use of CGM's transmission and distribution system.

IGU provided expert evidence by Mr. Patrick Bowman and relied upon the advice and input of Mr. Dale Friesen of InterGroup Consultants. The independent evidence filed by Mr. Bowman (IGU-8), along with comments provided through Counsel on matters related to the issues, scope, process, and timeline (IGU-2, IGU-3, IGU-7, IGU-10) provide a concise summary of the positions held by IGU. Koch also retained its own independent expert, Mr. Brian Collins.

HEARING SCOPE

It important at the outset to recognize the scope of this hearing as established by the Board in Order 36/22 (April 7, 2022) and reiterated in Order 58/22 (May 31, 2022) regarding the IGU motion for further disclosure.

This hearing is scoped to focus only on the core methodological questions related to the following items:

1. Allocation of Transmission and Distribution Plant;
2. Determination of Downstream Demand Allocation Factors;
3. Direct Assignment of High-Pressure Transmission Plant to Customers Classes, including Postage Stamp Ratemaking;
4. Classification and Allocation of Distribution Plant, including the indexing of the service line study to current costs;
5. Allocation of Upstream Capacity Resources;
6. Allocation of Demand-Side Management Costs;
7. Amendments to the COSS Methodology for Rate Re-bundling impacts;
8. Elimination of the Co-op Class;
9. Allocation of Operation & Maintenance, Customer Service, and Administrative Expenses; and
10. Near-Term Rate Impact Measure for the Special Contract Class and Power Station Class. (Order 36/22).

With respect to the current proceeding, IGU submits there is sufficient information for the Board to issue conclusive decisions on all matters address by the Atrium recommendations, with the exception of one item (use of a stack-based allocation for upstream and downstream capacity resources) which CGM has proposed to implement based only on the Atrium alternative approach, and not the primary Atrium recommendation (IGU supports further quantification of this issue, and final resolution at the next CGM GRA). IGU also submits there is sufficient information to make substantive determinations and directives on the remaining matters that were not addressed by Atrium in its five main recommendations.

This conclusion regarding sufficiency of the evidence arises from two considerations:

- Firstly, this proceeding is not structured to address every detail regarding the COS methods, where such details need to be informed by up-to-date quantitative inputs to ensure an appropriate method is selected. Such considerations (such as stack-based allocation) should be addressed only after proper quantification is provided.
- Secondly, this proceeding is not about perfecting COS implementation. It is limited to questions of primary methodology.

In this manner, the proceeding is not about achieving a perfect model or allocation methodology. It is about resolving the most significant and pressing issues, with multiple smaller implementation-related or detail-oriented issues left to a future General Rate Application (GRA) proceeding, when the appropriate data will need to be made available for testing.

In IGU's submission, given this limited framework for decision-making, the Board is well-equipped to make decisions regarding the recommendations contained in this submission.

ATRIUM RECOMMENDATIONS

Centra retained Atrium to provide expert and independent advice to the Utility, the Board, and Intervenors. Centra has made Atrium available for testing and provided a full copy of their terms of reference and report.

Atrium concluded with five key recommendations[1]:

1) Coincident Peak Day Allocation Method
2) Centra's Design Day Peak as the Preferred Method
3) Direct Assignment of Transmission Plant to the Special Contract Customer
4) Refresh the Development of the Customer Component of Distribution Mains
5) Identified Alternative Approach to the Allocation of Upstream Capacity Resources

Parties were given the opportunity to comment on the independence and expertise of Atrium. No party objected to Atrium's independence or expertise[2].

In IGU's submission, Centra did not appropriately manage the Atrium engagement in a manner that maximized the actual and perceived independence of the Atrium assignment. Best practice for independent expertise in a regulatory forum should have included a number of steps that Atrium did not perform. For example, Atrium did not conduct scoping of their assignment with Intervenors, only CGM. Further, Atrium relied on past intervenor submissions from the previous GRA to indicate where issues may exist; however, the previous GRA had explicitly excluded COS methods from the scope, so using the limited comments from Intervenors in that GRA as a scoping resource should not have been assumed to be comprehensive. Past independent experts before this PUB, and other regulators, have included scoping exercises with intervenors.

Nonetheless, despite these issues with the format of the Atrium assignment, IGU is satisfied that Atrium's work and conclusions represent the views of an experienced expert in the field, independent of

[1] Centra Exhibit 14, pdf page 5 of 20.
[2] Intervenor submissions March 14, 2022.

any party to the proceeding (including Centra), and that Atrium's recommendations are well-founded and supported by industry-standard principles.

Atrium has also indicated an ongoing reflective and thoughtful consideration of the issues, including evolution in its recommendations for matters outside of the five main recommendations within its report. For example, Atrium advanced its position on Unaccounted For Gas (UFG) in IR PUB/Atrium I-8a-b, where Atrium noted that more recent review of the issue had resulted in an additional Atrium recommendation – that the CGM UFG study be updated, and that the recovery of UFG costs be revised to focus on better tracking. Atrium also advanced its position on Demand-Side Management (DSM) cost allocation, noting that:

> …the program bundles and the corresponding customer segments identified in the Efficiency Manitoba 2020/23 Efficiency Plan suggest that the natural gas DSM programs are targeted at those specific consumer markets and therefore the associated costs can be identified for direct assignment to the appropriate customer classes, which is consistent with utility cost of service principles

Both these updated Atrium recommendations are sound and should be adopted.

In respect of the original five recommendations from Atrium, Exhibit Centra-14 provides the following useful summary of perspectives in this current proceeding:

Atrium Recommendation	**Party Supports or Does Not Oppose**	**Party Opposes**
Coincident Peak Day Allocation Method	Centra Industrial Gas Users Koch Fertilizer Canada, ULC	Consumers Association of Canada
Centra's Design Day Peak is the Preferred Method	Centra Industrial Gas Users Koch Fertilizer Canada, ULC	Consumers Association of Canada
Direct Assignment of Transmission Plant to the Special Contract Customer	Centra Industrial Gas Users Koch Fertilizer Canada, ULC	Consumers Association of Canada
Refresh the Development of the Customer Component of Distribution Mains	Centra Industrial Gas Users Koch Fertilizer Canada, ULC Consumers Association of Canada	None Identified
Alternative Approach to the Allocation of Upstream Capacity Resources	Centra Industrial Gas Users Koch Fertilizer Canada, ULC	Consumers Association of Canada

Based on the above, no further comment appears necessary on the fourth item - the refresh of the development of the customer component of distribution mains.

On the remaining 4 issues, only the Consumers Association of Canada (CAC) has indicated opposition.

The CAC evidence in regard to the above four positions opposing Atrium's recommendations hinges in large part on a very simple difference in the understanding of the purpose of Cost-of-Service analysis in

Manitoba in modern times, and indeed even as compared to 1996 when the last full Centra Cost-of-Service review took place.

In the 1996 review, the Board accepted methodologies that explicitly included considerations beyond cost causation, particularly in regard to the recommendation to adopt a Peak and Average approach to cost allocation, rather than a Coincident Peak (CP) method (as recommended by Atrium in #1 above), and the Atrium recommendation for a Design Day implementation of the CP method (#2 above - collectively, an approach known as a "Peak Day" allocation). The acceptance of considerations beyond cost causation is evidenced by the description from Centra's own Cost-of-Service consultant from 1996, R.J. Rudden and Associated (RJRA), as follows[3]:

> RJRA's recommendation regarding demand allocators is that the Peak Day methodology is the most clearly cost-based approach, since it conforms to the planning processes of an LDC. However, in recognition of the alternative view that utilization (annual consumption) also has an influence on costs (in some undefined manner), we also recognize Peak and Average as a reasonable allocator for demand-related costs.

The RJRA conclusion sets the issue explicitly – a peak based methodology (as now recommended by Atrium) is the "most clearly cost-based approach". However, RJRA then yielded on the principled cost-based approach by noting[4]:

> Cost-based rates should be the key rate design principle within Centra. It appears that the company, its customers, and the Public Utilities Board all feel that rates should be cost-based. RJRA has always been supportive of cost-based rates, with the caveat that customer impact, gradualism and market conditions also need to be considered.

The RJRA consideration of broader factors is also highlighted in Centra's current Exhibit 13, the rebuttal evidence, where a transcript excerpt from 1996 clarifies that "…to reflect the inclusion of non-cost causal factors, R.J. Rudden & Associates recommended the use of the peak and average methodology for purposes of revenue allocation among Centra's classes of service"[5]

The RJRA study goes astray from cost-causation in its eye towards results-based analysis of rate impacts. This type of approach, which neglects adherence to principled cost causation, has since been explicitly rejected in Manitoba, including in Board Order 164/16 where the Board issued a finding that inclusion of non-cost-causal factors result in a COS study that is "muddled"[6].

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[3] MFR-7 pdf page 36 of 102.

[4] MFR-7 pdf page 43 of 102.

[5] Quotation from pages 48-19 of the Centra 1996 COS methodology review transcript, as quoted in Centra Exhibit 13 in this proceeding, pdf page 5 of 16.

[6] Order 164/16, pdf page 38 of 116.

In its Order 164/16 on Manitoba Hydro's COS study, the Board noted that the public hearing process was the first review of Manitoba Hydro's COS methodology in a decade.[7] With respect to the purpose of a COS study, the Board stated[8]:

> The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage…

The Board has already explicitly rejected the approach adopted by Centra and RJRA in 1996, wherein considerations beyond cost causation, such as rate impacts, are factored in.

More specific to the CAC position, the experts for the CAC opine repeatedly that the PUB has "a long-standing policy of a broad definition of cost causation that considers and gives weight to both system planning and system operation and use."[9] CAC's experts provide multiple quotes from PUB decisions, both from 1996 and 2016, that include the word "use"[10] that CAC's experts portray as a PUB "policy" and make a conclusion that[11]:

> The definition of cost causation is broader than only considering strict engineering design parameters. The broader definition of cost causation in the PUB COS policy should consider and give weight to both how the energy system is designed to planned, as well as how the system is operated, used and usage patterns. The boarder definition of cost causation in the PUB COS policy should consider and give weight to all of the uses and benefits of assets, including primary and secondary uses and benefits, over a range of years (and not just the test year) and over a range of operating conditions.

The CAC expert's assertion is odd in that it appears no party in the hearing disagrees with the apparent assertion – that use is also relevant to cost allocation. But the issue is the CAC experts entirely miss the point that it is not just any "use" that is included in a proper cost allocation exercise, but specifically the uses that drive costs. The fallacy of the CAC logic is summarized by Mr. Bowman in response to CACM/IGU-I-1, where he noted.

> Both design and operation can be relevant to cost causation.
>
> Cost causation can take different forms. One form is the fact that an asset was planned (and the cost incurred) for a particular purpose. A second form is the fact that an asset may be used (and ongoing costs incurred) for a different purpose.
>
> Consider, for example, the Manitoba Hydro Brandon combustion turbines and their role in the electrical system. The assets were planned, and the cost incurred, to provide both energy (drought backup) and, to a lesser extent, capacity benefits. As the Manitoba Hydro system evolves, with major new northern hydro generation, and major new import capabilities, the Brandon combustion turbines may play a

[7] Page 14 of 116. Board Order 164/16 dated December 20, 2016.
[8] Pages 27 and 28 of Board Order 164/16.
[9] CAC Exhibit 8, page 11
[10] CAC Exhibit 8, page 11-13
[11] CAC Exhibit 8, page 13.

> different role – one linked solely to capacity (e.g., Brandon area support, or supply at peak times when other units are out of service). In future, the only reason for maintaining (and continuing to incur the costs) of the Brandon turbines may therefore be for capacity reasons, and it may be reasonable to re-classify their costs to 100% capacity based on "use".
>
> This is still a cost causation rationale – the use that causes their costs to continue to be incurred is capacity. That may not have been the original reason they were planned or built, but their use has changed.
>
> This is entirely different than a loose principle to just charge everyone who uses something simply because they use it or were originally intended to use it when it was planned. That is the antithesis of a cost causation framework[12].

Atrium similarly accepts the basic premise set out by CAC that one must consider more than only "strict engineering design parameters" noting[13]:

> Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the utility system.

In short, contrary to CAC's assertions, Atrium also does not reject the concept that operations can be relevant to cost causation. In fact, Atrium confirmed it did consider use – but only to the extent that use drives costs, precisely as described by Mr. Bowman above. Note the following excerpt from Atrium's rebuttal evidence[14]:

> Atrium did review system usage and operations when evaluating costing to understand how these contributed to cost incurrence in general and to individual customer costs in particular. The result of the review was a determination that new methods were appropriate given the existing utility operations.

In addition to Atrium, CGM address the weaknesses in the CAC's argument, and how an appropriate application of concept of "use" does not mean rejection of cost causation as a priority, but an enhancement of it. Note CGM's Rebuttal evidence[15]:

> Consideration of how an asset is used needs to be done in the context of determining which customers cause the utility to incur the specific costs such that an appropriate cost-causal linkage can be drawn.

Centra similarly addresses the matter in its final submission[16]:

> CAC Consultants advocate for a "broad" definition of cost causation and assert that Centra's characterization of its proposals being "a better reflection of pure cost-causation" can be interpreted to mean that Centra is narrowing its definition and no

[12] CACM/IGU-I-1
[13] Application, Appendix 1, pdf page 10 of 89.
[14] CGM Exhibit 14, pdf page 9 of 20.
[15] CGM Exhibit 13, pdf page 4 of 16.
[16] CGM Exhibit 16, pdf page 8-9 of 28.

> longer considering system operation and use in addition to system design in its allocation methodology. This is simply not the case – Centra's proposals consider the nature of Centra's operations, and the way customers use the upstream and downstream facilities, in addition to the way Centra designs the system. Such considerations are necessary when determining cost causation as they can explain why the system was designed the way it was, why certain investments were made, or how the system evolved to how it operates today.

It must also be noted that the result of the CAC proposal and the purported "policy" is a broad, vague set of principles for costing that are not founded in causation. The evidence of Brubaker and Associates, by Brian C. Collins, also echoes the importance of cost causal factors, noting "non cost causal factors should be addressed in the rate design process"[17].

Atrium is clear in their rebuttal[18]:

> CAC desires an outcome that ignores true cost responsibility, punishes economic efficiency, distorts market signals, and encourages inefficient energy choices. The position is untenable.

In short, CAC's evidence reflects a significant misunderstanding of the nexus between cost causation and use. Many of CGM's existing methods are inferior because they allocate costs based on system use, in a non-cost-causal manner. The appropriate consideration of system use in cost causation is related to cases where use drives costs, not in a simple blanket allocation to any and all system uses.

The remainder of this section addresses the merits of each of Atrium's four contested recommendations.

Coincident Peak Day Allocation Method

Atrium's recommendation to allocate demand-related costs on the basis of Coincident Peak (CP) is addressed at length in every expert submission to the Board in this proceeding.

Mr. Bowman supports this Atrium recommendation in his Recommendation #1[19].

Despite the extensive material filed on this matter, at its core, the essential matter of dispute is fully addressed above: should non-cost-causal factors be included in COS analysis, in which case there is a potential argument for retaining the Peak-and-Average approach, or should the Board retain its focus on cost causation as it did in 2016 and since, in which case there is no credible argument for retaining Peak-and-Average and the proposed CP method should be adopted.

Atrium addressed this matter at length, first summarizing the key consideration for adopting a CP methodology, as follows[20]:

> The concept of Coincident Peak (CP) demand allocation is premised on the notion that investment in capacity is determined by the peak load(s) of the utility. Under

[17] Koch Exhibit 3, pdf page 5 of 33.
[18] CGM Exhibit 14, pdf page 10 of 20.
[19] IGU Exhibit 8, page 7.
[20] CGM Application, Appendix 1, pdf page 10.

> this methodology, demand related costs are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class.

The factual underpinning that investment in capacity is determined by the peak load of the utility has not been challenged. Centra confirmed this in the original application, at page 30[21]:

> To reliably meet the requirements of all customers, the transmission and distribution system must be able to supply the peak demand on the system. Design Day corresponds to the day with the highest coincident system peak conditions that the system is designed to meet under extreme weather conditions.

And further[22]:

> … Centra uses a peak design hour approach for planning purposes …

In short, the pre-condition for using CP posited by Atrium – that investment in capacity is determined by the peak loads of the utility – is confirmed.

In contrast to the use of a clearly justified "peak" allocator, the Koch expert in this proceeding (Collins) made clear why an "average" consideration in system design is not appropriate, as follows[23]:

> A system designed to meet average demand would be incapable of providing service to customers on all days colder than average.

In this regard, "average" in the above extract would relate to the average across the year. Such a system is clearly neither factually in place, nor desirable.

Mr. Bowman also highlighted how peak continues to remain relevant to ongoing system investment. Using the example of the Winnipeg North West Project, which was the largest transmission mains plant addition in the past decade, "by a factor of 10", Mr. Bowman referenced the justification for the project as set out in Centra's capital project briefs, as follows [footnotes omitted][24]:

> 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."
>
> 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 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."

[21] CGM Exhibit 2-0, pdf page 31 of 41.
[22] Centra Exhibit 2-0, pdf page 31 of 41.
[23] Koch Exhibit 3, pdf page 4-5 of 33.
[24] IGU Exhibit 8, page 5-6. Also see the response to CACM/IGU-I-3(d) and 3(e).

> 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.

On the matter of limited precedence in the utility industry for adoption, at times, of the Peak-and-Average methodology, this fact is not in dispute. Atrium notes seven examples in North America, in PUB/Atrium-I-1(a). However, the Board has no evidence regarding the approach being used in cases analogous to Centra, and at least two examples of the approach being used in cases, which are clearly not analogous to Centra – Indiana (CAC/Atrium-I-2f) and Alaska (CACM/IGU(Bowman)-I-3(d)).

IGU also notes that, in support if its advocacy for the retention of non-cost-causal factors, CAC also relies on a number of statements or assertions that are simply incorrect:

- CAC posits to Mr. Bowman in CACM/IGU(Bowman)-I-3(a) that NARUC (the National Association of Regulatory Utility Commissioners in the United States) considers multiple methods, including Peak and Average, to have received the organization's "endorsement". NARUC provides no such endorsement[25].
- CAC experts assert that the Peak-and-Average method is part of "a broader definition of cost causation that encompasses both system planning and system operation and use". This is incorrect. As highlighted above, Peak-and-Average was explicitly adopted as a non-cost-causal factor (a fact clearly expressed by Centra's consultants in 1996, RJRA).

On the basis of the above considerations, IGU supports the recommendations of Atrium for adoption of a CP methodology for Demand-Related costs.

Centra's Design Peak

Atrium's second recommendation, also tied to demand-related costs, is to use a design peak for the purposes of allocation. Specifically, Atrium notes[26]:

> While Centra's CP day is an appropriate construct for a historical peak demand allocator, Atrium recommends the use of Centra's design day demand as an improvement to using its actual peak day demand or an historical average of multiple peak day demands over time for purposes of deriving demand allocation.

CGM clarifies its implementation plan with regard to this recommendation in its response to PUB/Centra-I-9(a), where CGM notes: "Centra commits to having the design day metric by customer class prior the next GRA." Key to this data development is that the peak in question should reflect the peak to which CGM designs the system (e.g., extreme cold temperatures) not the peak which underpins the load and revenue forecast in any given Test Year, which can reflect more normal low temperatures but still short of design extremes. It appears CGM agrees with this distinction, as noted in the response to IGU/Centra-I-4a-k:

> Centra would clarify that the difference between a Design Day Allocator and a Coincident Peak Day allocator (as currently in use by Centra) is temperature. Both

[25] CACM/IGU(Bowman-I-3(a).

[26] Application, Appendix 1, pdf page 15 of 89

> allocators take into consideration the forecast demand of Centra's classes, i.e., their usage, on the peak day. For Centra's current peak and average allocator and the coincident peak allocator used in the illustrative result in Appendix 4 peak day is calculated based on an average winter. In Atrium's proposal the design day would not reflect an average winter but rather would reflect the coldest day that Centra incorporates into its planning processes. Centra anticipates that switching to a design day peak definition from the current coincident peak day definition will result in less costs being allocated to classes whose usage is less influenced by weather.

This approach is appropriate and reflective of cost causation. It is also consistent with Mr. Bowman's Recommendation #2[27]. The approach is also supported by Mr. Collins, who notes[28]:

> Therefore, the use of Design Day Demand is appropriate as compared to actual peak demands or the average of multiple annual peak demands because the system is designed and costs incurred by Centra to meet the expected system Design Day Demand.

It does not appear any other party takes issue with this recommendation, except CAC, who suggests that the metric is a "pseudo" parameter[29] as it not used by Centra in system planning. Centra unequivocally contests this assertion in rebuttal evidence, as follows[30]:

> Centra is not developing a "pseudo maximum design day". The process underlined in PUB/CENTRA I-8 b) and PUB/CENTRA I-9 a) reflects the fact that Centra does not have demand metering for all of its customer classes. As a result, Centra uses multiple years of data to determine the relationship between peak day and annual load in order to determine the base and heat components of load by customer class. This data is then used to determine each class' respective share of load on Centra's maximum peak day (i.e Design Day). CAC also incorrectly asserts that Centra does not use a maximum design day for planning purposes despite Centra's response in PUB/CENTRA I-9 d) that it is used in gas supply planning for upstream capacity.

As a result, the Atrium recommendations, and Centra's apparent proposed approach to implementing the recommendations, are sound and consistent with cost allocation, and should be approved by the Board.

Direct Allocation to the Special Contract Customer

Atrium's third recommendation is that only those Transmission Costs directly related to serving the Special Contract customer should be included in the cost allocation to this customer.

[27] IGU Exhibit 8, page 7.
[28] Koch Exhibit 3, pdf page 7 of 33.
[29] CAC Exhibit 8, pdf page 26 of 46.
[30] CGM Exhibit 13, pdf page 11 of 16.

Atrium bases this recommendation on the following principle[31]:

> If a direct linkage between a utility's customers and the particular costs incurred by the utility in serving those customers is established, that cost is deemed a directly assignable cost.

CGM provides a concise summary of the factual basis driving the CGM and Atrium recommendation. The Atrium report notes the following[32]:

- The costs of the assets serving these customers can be clearly identified from other costs;
- The assets are not used to serve other customers except under extenuating circumstances outside of normal operating conditions;
- The pipelines have a one-way relationship with the rest of the system;
- The Special Contract Customer and Brandon Power Station are unable to utilize any other portions of Centra's system due to their requirement for un-odourized gas; and,
- The Special Contract Customer and Brandon Power Station are unable to utilize any other portions of Centra's system due to their high pressure requirements

CGM also notes[33]:

> …the direct assignment approach reflects the fact that the other transmission assets that make up the integrated system provide no benefits to the Special Contract Customer as there are no other portions of the system (with the exception of the facilities serving the Brandon CT) that can be used to serve their load. The proposed approach therefore is not obviating costs attributable to the Special Contract Customer and shifting them to other customers but rather is attempting to properly reflect the costs being driven by the respective classes.

Mr. Bowman supports this approach, in his Recommendation #3[34]. Specifically, Mr. Bowman noted that:

> 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.

[31] CGM Application, Appendix 1, pdf page 19 of 89.
[32] As summarized in CGM Exhibit 16, pdf page 13 of 28.
[33] CGM Exhibit 16, pdf page 16 of 28.
[34] IGU Exhibit 8, page 8-9.

Mr. Bowman further noted in respect of the Special Contract customer[35] [footnotes omitted]:

> 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.” 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.

CAC provided interrogatories to Mr. Bowman that requested his view on the historical development of the Brandon system, and the extent to which such history negates the basis for the recommendation. Mr. Bowman responded[36]:

> … the Special Contract and Power Station customers still represent a textbook case for direct allocation. These customers cause the need for infrastructure that can deliver high pressure non-odourized gas. They cause no need for infrastructure that delivers gas at a lower pressure (e.g., 4140 kPa or below) as the Special Contract customer cannot receive gas at this pressure (according to Centra, as the “Special Contract Class customer has an inlet pressure requirement that exceeds the maximum operation pressure of the 1956 pipeline”, which is stated to be 4140 kPa in CAC/Centra I-11a). They also do not cause or make use of pipelines carrying odorized gas.
>
> In the event that a customer previously used other infrastructure, they have no more ongoing cost causation responsibility for any previously used infrastructure than any resident who previously resided in Brandon but has since moved away. This is why the concept of cost causation includes both “design” and “use”.

Koch’s expert, Collins, similarly supports the direct assignment, and provides a key supporting literature excerpt from the NARUC Gas Distribution Rate Design Manual, as follows[37]:

> Once a definition of cost is decided upon, it is then necessary to assign costs to specific customer classes. Generally speaking, these costs can be divided into two broad categories: direct costs and common costs. Direct costs are those which are incurred only to provide service to a particular customer class. Common costs are incurred in providing service to more than one class. The assignment of direct costs is straight-forward and should not be subject to debate. Common costs are another matter.

Mr. Collins has also explained that the odourant is a contaminant to Koch’s production process. Using odourized gas is therefore not an option for Koch.[38]

[35] IGU Exhibit 8, page 8.
[36] CACM/IGU(Bowman)-I-4.
[37] Koch Exhibit 3, pdf page 9 of 33, quoting from NARUC Gas Distribution Rate Design Manual, 1989, pages 18-19.
[38] Centra/Koch I-2.

The only party who rejects the Atrium recommendation is CAC. However, the CAC position on this matter is confusing, particularly in light of the above-noted discussion on the importance CAC's experts place on considering the "use" of an asset as a cost allocation driver. CAC's expert evidence focuses primarily on a cursory review of history for serving the Brandon area, but appears to entirely ignore the fact that the current configuration, and the uses made of the Transmission system by customers, leads to no overlap between the Special Contract customer (using precisely defined pipelines at unique pressures and containing deodorized gas), and the other customers (using entirely separate transmission, at lower pressures, and containing odorized gas). As such, the CAC recommendations are internally inconsistent with both the acknowledged facts of the system as currently configured, and with the priorities for cost allocation tied to both planning and use.

In light of the above considerations, the Board should approve the Atrium recommendations in respect of the direct assignment of transmission expenses.

Allocation of Upstream Capacity Resources

The final contested Atrium recommendation is the proposal to allocation upstream capacity resources on the basis of a stack-based analysis, or alternatively winter season demand in excess of summer season demand. CGM has adopted this recommendation using the latter alternative, an allocation based on winter season demand in excess of summer season demand[39]. Atrium sets out a detailed description of how the stack-based approach would be applied, and the benefits, in the response to PUB/Atrium-I-10(a).

Mr. Bowman has indicated support for the principle established by Atrium (Bowman Recommendation #5)[40]. However, Mr. Bowman takes issue with the reversion by CGM to the winter excess approach (an approach which he considers "inferior"[41] to the stack-based approach). At the same time, Mr. Bowman notes that quantitative data on the potential impact of the differences is not available. The stack-based approach, while conceptually more accurate and logical, brings with it more complexity, and likely more need to rely on commercially sensitive information, which will be difficult to review and test at future GRAs. For this reason, Mr. Bowman recommends the Board confirm that one of the above two approaches will be adopted for upstream capacity resources, and leave the decision as to which approach will be applied to the next GRA when quantified information on the differences in outcomes between the two approaches can be presented (including, most notably, whether the extra complexity of the stack-based approach yield material differences in outcomes compared to the much simpler winter excess approach).

The only party indicating apparent opposition to the Atrium recommendations is CAC. However, the CAC recommendation appears merely aligned with the remainder of the CAC evidence regarding retaining the pervasive use of Peak-and-Average allocation methods. The CAC recommendation is not well founded, in that Peak-and-Average is a method that penalizes high load factor (i.e., flat annual load profile) users, as described by Koch witness Collins[42]:

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[39] CGM Exhibit 16, pdf page 4 of 28.
[40] IGU Exhibit 8, page 11
[41] IGU Exhibit 8, page 10.
[42] Koch Exhibit 3, pdf page 5 of 33.

> …the P&A method is illogical because it allocates even more costs to those customers that increase system load factor and punishes efficient usage.

In contrast to the Peak-and-Average skew against high load factor customers, the Atrium recommendation is explicitly designed to ensure that it is low load factor (winter peaking) customers that bear a greater responsibility for upstream capacity costs, precisely as it is low load factor winter use which most drives these costs, as noted by Atrium[43]:

> From a purely cost causation perspective, the contracted level of storage and related pipeline transportation capacity serve the cumulative design day peak and winter season demands of those customers by those winter season upstream resources, which are in excess of the level of year-round pipeline capacity.

CGM expands on this point, as follows[44]:

> …the Winter Demand in Excess of Summer Demand allocator recognizes the fact that the costs of storage and related pipeline capacity are incurred in order to meet the winter volumes that are over and above the volumes associated with summer use. In contrast, total annual volumes, as used in the Peak and Average allocator, do not determine the capacity of storage required. From a cost causation perspective, use of a Peak and Average allocator does not recognize the excess cost Centra incurs to serve low load factor customers in the winter.

In short, it appears there is no logical or supportable basis for CAC's recommendation to retain the Peak-and-Average methodology for capacity-related resources. The Atrium recommended approaches should be recognized by the Board as a significant improvement in COS methodology, and both approaches should be directed to be analyzed prior to making a final determination in CGM's next GRA (as recommended by Mr. Bowman).

MATTERS OUTSIDE OF THE ORIGINAL ATRIUM RECOMMENDATION

Demand Side Management

On the matter of Demand Side Management ("DSM"), CGM's current approach to cost allocation is to allocate DSM costs "to the customer classes based on the forecasted participation by customer class."[45] CGM proposes to retain this approach[46].

The alternative approach, as set out by the CAC experts, is to allocate consistent with other demand-related costs[47]. CAC asserts this is equivalent to the approach used by Manitoba Hydro, which consider DSM a system resource due to its role in generation and transmission cost reductions and deferral.

[43] PUB/Atrium-I-11(a).
[44] Centra Exhibit 16, pdf page 19 of 28.
[45] CGM Application, Appendix 1, pdf page 25 of 89.
[46] CGM Exhibit 16, pdf page 22 of 28.
[47] CAC Exhibit 8, page 36.

CAC also asserts that CGM proposal for classification to energy and allocation to the participating classes will result in T-Service customers and Direct Purchase customers avoiding cost responsibility for DSM[48]. In this assertion, CAC is incorrect, as confirmed by CGM in rebuttal evidence[49]:

> Participation in programming through Efficiency Manitoba or formerly through Centra's DSM Program is not predicated on purchasing gas from Centra. As such, to the extent that programming is offered to classes with T-Service or Direct Purchase customers, those customers have the ability to benefit through participation and therefore are assigned a portion of the associated costs.

As to the CAC proposal to allocate DSM on the basis of demand, CAC appears to rely on two basic concepts for support this approach. Each is incorrect and inappropriate for cost allocation.

First, CAC indicates DSM is a system resource because in theory it can result in system savings from avoided peak. However, CAC provides no evidence in support of this assertion other than a generic potential linkage. In fact, DSM for gas customers does not rely whatsoever on system capacity savings, as set out in the Efficiency Manitoba Application for its 2020-23 three-year energy efficiency plan, as follows[50]:

> It is Efficiency Manitoba's understanding there are no avoided cost components included within the natural gas marginal benefits associated with the deferral of natural gas distribution or transmission facilities.

Note that even in the case of Manitoba Hydro, the Board found that DSM was a generation resource, and did not avoid the costs of Transmission and Distribution.[51] The equivalent system contribution to gas DSM would be as a gas supply resource. As a gas supply resource, 100% of the benefit of the DSM would accrue to the customer whose conservation activities led to not using the units of gas – there would be no "system" benefit.

Second, CAC relies upon a generic claim that gas DSM should be allocated on the basis of capacity because it provides "overall societal benefits" and meets "societal imperatives".[52] CAC provides no linkage between such societal benefits and a capacity allocation – for example, if the benefits are socially delivered, why allocate on the basis of demand, rather than equally to each customer? More specifically, this broad social benefit linked rationale must be recognized as being entirely divorced from cost causation from the outset. The range of cost allocation methods that this rationale may yield is simply nonsensical – for example, should all Portage la Prairie residents be allocated a portion of the supply costs to Simplot or Roquette because of clear societal economic development benefits they provide? Should a portion of the costs otherwise caused by hospitals and schools be allocated to residential consumers since these facilities provide educational or health benefits to the neighbourhood?

[48] CAC Exhibit 8, page 38.
[49] CGM Exhibit 13, pdf page 15 of 16.
[50] Efficiency Manitoba Application for the 2020/23 Efficiency Plan, pdf page 131 of 591.
[51] PUB Order 164/16, page 85 of 116
[52] CAC Exhibit 8, page 38.

Atrium addresses the only cost causal rationale raised by CAC in response to PUB/Atrium I-9b. The PUB set out a premise that DSM on the gas system could be found to be a system resource, and asked for Atrium's recommendation in that event. Atrium indicated as follows[53]:

> Under the assumption that there is an evidentiary basis that supports the finding of the Board that DSM is a system resource, there would presumably be some consistency between the methods for recovery of the DSM costs between electric and gas customers in Manitoba. However, the program bundles and the corresponding customer segments identified in the Efficiency Manitoba 2020/23 Efficiency Plan suggest that the natural gas DSM programs are targeted at those specific consumer markets and therefore the associated costs can be identified for direct assignment to the appropriate customer classes, which is consistent with utility cost of service principles.

On the basis of the above evidence, the recommendations from CAC that DSM should be treated as a gas system resource, and that gas system cost allocation should consider DSM a capacity resource are unsupported and not consistent with the facts in Manitoba. Further, the proposal to consider social value of the DSM activity as a basis for cost allocation is entirely without merit. The existing CGM approach to DSM cost allocation should be retained.

Storage Costs in Rate Base

Centra's final submission summarizes the issue of the rate base related costs of gas in storage, noting[54] [footnoted omitted]:

> Centra did not initially propose a methodology change to the way it treats Gas in Storage in Rate Base, however upon reflecting on the recommendation from InterGroup's evidence, Centra agrees that a refinement to the way the costs are currently treated would be a better reflection of cost causation.
>
> …
>
> As it is winter usage that drives costs associated with storage, a refinement to Centra's current approach that uses annual volumes is to functionalize the costs as Storage, classify as Energy and allocate using winter volumes.

IGU accepts this revision to CGM's methods as addressing the matters raised by Mr. Bowman in a directionally-appropriate way. No other party appears to have addressed this matter in their evidence. IGU recommends the Board approve this revision.

Unaccounted For Gas

[53] PUB/Atrium-I-9(b)
[54] CGM Exhibit 16, pdf page 26 of 28.

In their original report, Atrium provides little to no comment on the allocation of Unaccounted For Gas (UFG). Ultimately, Atrium did develop a recommendation that CGM should conduct an updated UFG study, to replace the study completed in 2004[55].

Centra has adopted this recommendation, and indicates in the Final Submission that it proposes to "review the allocation of Unaccounted For Gas and report on its status" [56].

IGU is encouraged that CGM recognizes the limitations inherent in a 2004 study. Since that time, major system configuration changes have occurred, and the amount of UFG has declined markedly[57], almost in half. However, the tone of CGM's proposal suggests a less than thorough commitment, to a mere "review". This is insufficient given CGM's past history on the matter. In particular, the 2004 study was explicitly noted by the PUB to need attention which it has not received from CGM. The Board specifically noted in 2004[58]:

> The Board encourages CGM to continue its review of UFG, and consult with other interested parties

However, it appears no update or review of the study has been undertaken since 2004[59].

IGU is also concerned that the approach to the study (provided in MFR-10) focuses on causation tied to identified factors (such as the likelihood of metering issues) and a loose allocation of the remaining unquantified factors across the various customer classes. Mr. Bowman noted his concerns with this approach, as follows[60]:

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

In IGU's submission, the "review" proposed by Centra[61], with no target date for completion, is simply unacceptably vague. The Board should ensure to direct to CGM that a full update of the UFG study

[55] PUB/Atrium-I-8a-b.
[56] CGM Exhibit 16, pdf page 5 of 28.
[57] See IGU Exhibit 8, page 18
[58] Order 131/04, page 39.
[59] IGU/Centra-I-6(b).
[60] IGU Exhibit 8, page 18.
[61] CGM Exhibit 16, pdf page 5 of 28.

should be undertaken, including allocation of unquantified residual components of the UFG to the Transmission versus Distribution systems as appropriate, with a specified completion date, ideally within 12 months.

Mainline Firm Cost Allocation Principles

In respect of the allocation of costs to the second largest group of users on the system – the Mainline Firm class – Atrium and Centra have made no specific recommendations. The entirety of Atrium's conclusion in respect of the Mainline Firm class is as follows:

> Atrium reviewed system maps and were given briefings by Centra personnel familiar with the Centra system, including commercially sensitive detailed descriptions of each Mainline customer and accompanying pipeline schematics, which Centra considers to be confidential. The Mainline customers are dispersed throughout the Centra transmission system and are located on transmission pipelines that serve both upstream and downstream load centers, ranging from transmission pressures of 600 PSIG (4,135 kPa) to the upper range of what is currently classified as distribution pressure in Table 1. Based on our review of the transmission pipelines serving individual Mainline Class customers, it is Atrium's view that it is appropriate for the Mainline Class to receive a full allocation of the transmission system plant. However, the characteristics previously discussed that are applicable to the Special Contract customer do not apply to individual Mainline customers; and therefore, these customers are not candidates for a direct assignment of specific transmission pipeline related plant.

Atrium does not comment on the allocation of distribution plant to Mainline Firm customers.

Mainline Firm Customers are 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.[62]

Mr. Bowman's evidence notes the original development of the Mainline Class, as follows:

> 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 that are clearly served directly and exclusively from the transmission system through dedicated or strictly identifiable facilities. [MFR 7 Attachment pdf page 17 of 102.]
>
> For these customers, many of CGM's functions are of little to no relevance.

[62] Application Appendix 2, page 4.

> 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).

Fundamentally, on the basis of this customer definition, Mainline customers can only be connected to the system in one of two ways. First, they can connect to a transmission system operating at above 1900 kPa. Second, they can be served by the development of customer-specific assets <1900 kPa which permit connection to the system at >1900 kPa.

Mr. Bowman ultimately concludes that based on the data available, it appears the Mainline class of customers are being overallocated costs related to distribution. He addresses this conclusion related to two areas[63]:

1) Some assets are functionalized as transmission, which should not be considered transmission, as the pressures are too low (i.e., below 1900 kPa); and,
2) Assets functionalized as distribution are allocated to Mainline customers, which should not be making use of the distribution system (<1900 kPa), except through definable specifically assigned or specifically-assignable assets.

In respect of this principled structure for a Mainline class, the customers should only use, and only be allocated, costs for using the >1900 kPa system (or for a small customer-specific connection to gain access to the >1900 kPa system). These customers should be limited to only an allocation of Transmission costs, and not Distribution costs.

The primary issue arises in the Centra portrayal of Mainline customers are having delivery pressures below 1900 kPa, and therefore being part of the distribution system (and consequently allocated distribution related costs). For example, the following extract from Centra's rebuttal evidence:

> Mainline customers can be served at pressures in excess of 700 kPA if it is through a dedicated line. In fact, approximately half of the Mainline customers are served at pressure less than >1900 kPA.
>
> Centra acknowledges that it could re-functionalize the six primary stations that reduce pressure to below >1900 kPA to distribution however the only customer classes that can not utilize these assets are the Power Station and Special Contract classes. Under the direct assignment approach proposed by Centra, this is unnecessary and adds a level of complexity with no real benefit.

Centra's submission highlights the issue that Centra considers the Mainline class of customers to be part of the general pool of customers who use the distribution system (this is why Centra indicates the customers would continue to be allocated the noted assets even though they were reclassified to

[63] IGU Exhibit 8, page 14.

distribution). Use of the general distribution system (outside of specific-use assets) by Mainline customers should not occur, and there is no evidence it does occur. The only <1900 kPa assets used by Mainline customers should be the "dedicated distribution" as set out in the customer class definition. Since the customer classes only use the dedicated distribution, which can be defined, the class should only pay for this dedicated distribution (as a specifically assigned asset) and not the general pool of all distribution assets on the Centra system.

The principles for such Direct Allocation are clear, well-founded in the literature, and described in detail earlier in this submission in respect of the Special Contract customer. In the case of Mainline customers, however, the assets to be Directly Allocated should be distribution assets, and, similar to the Special Contract customer, having received a Direct Allocation of all distribution assets relevant to service their class, the Mainline Firm customers should receive no further allocation of distribution system costs.

The issues at hand are material. The response to IGU/Centra I-7(c) indicates the allocation to Mainline customers of distribution plant exceeds $3 million.

The challenge in this proceeding is that, beyond the above principles, the specifics of the current approach and the potential development of alternative approaches, which may be more appropriately based in cost causation becomes an issue of detail, and of information that Centra considers to be confidential. Atrium also confirms this in noting that it was required to use confidential information to develop its perspectives on the Mainline class.

IGU recommends that the Board not accept the COS methods for allocation as it applies to Mainline Firm customers. There is insufficient information that the class has received a full assessment regarding the removal of distribution-related costs and assets (other than those specifically assigned to it) under the same principles as were applied to the Special Contract customer in this proceeding. IGU further recommends that the Board direct CGM to file in the next GRA a full characterization of the costs allocated to the Mainline class for functions above 1900 kPa versus below 1900 kPa, and a list of assets below 1900 kPa that drive this allocation of costs. If the list includes assets that do not meet the test of "dedicated" distribution, CGM must clarify why these assets are included and how the customer in question qualified for the Mainline class. More importantly, if the assets are dedicated, CGM should prepare a COS analysis of directly assigning only those dedicated distribution assets to the Mainline class and no further allocation of distribution-related costs, as would be justified by a cost-causation principle.

Special Contract Customer Rate Adjustment

There is unfortunately a long history of delay with respect to the review of rates charged by CGM. By PUB Order 108/15, the Board directed CGM to file a full General Rate Application on or before January 20, 2017. By Order 79/17 the PUB found CGM to be in default of Order 108/15 and took the unprecedented step of assessing a maximum daily penalty of $100 per day. CGM sought to review and vary Order 79/17 and advised that it anticipated filing a GRA no later than November 30, 2018. By Order 125/18, the PUB varied the administrative penalty and reduced it to $35 per day. At pages 8 and 9 of Order 125/18 the PUB noted its concern about CGM's history of delaying compliance to prior Board Directives.

By Order 24/19 dated February 20, 2019, the PUB included as issue 17 "Cost of Service Study results and methodology (allocation of costs to customer classes)".

Finally, it looked like the long overdue review of Cost of Service would take place.

However, by second procedural Order 98/19 dated July 15, 2019, the PUB determined there would be a separate COS methodology review following the conclusion of the 2019/20 GRA. The GRA would only consider bill mitigation.

At page 5, paragraph 15 of its submission in the 2019/20 GRA, Koch noted that implementation of the rates sought by CGM would result in an increase to the current rates in the order of 64% and that this would result in rate shock to Koch (paras. 9(b) and 10). At paragraph 10, Koch submitted:

> Due to the substantial uncertainty that exists regarding the reliability of the current Cost of Service Study, Koch recommends that the Board refrain from approving any change to the existing base rates in the interim until the cost of service rate methodology has been thoroughly reviewed in accordance with the process to be established.

By Order 152/19 dated October 11, 2019 the PUB issued several Orders including:

> 1. Centra's Application for approval of Supplemental Gas, Transportation (to Centra), Distribution (to Customer) Sales and Transportation rates, Basic Monthly Charges, the Primary Gas Overhead rate, and the Fixed Rate Primary Gas Service Program Cost Rate, effective November 1, 2019 **BE AND IS HEREBY APPROVED.**
>
> 3. Centra shall prepare and file an Integrated Cost Allocation Methodology report as a Minimum Filing Requirement for the next General Rate Application including the information required in this Order.
>
> 29. Centra shall file an application for a comprehensive review of its cost of service methodology by no later than May 1, 2020.

By these Orders, the PUB ended up rejecting Koch's submission for interim bill mitigation pending the COS review. If the timetable had been adhered to, the GRA implementing the COS review could have been filed in the fall of 2020. The same regulatory staff for CGM hearings are in the process of finalizing the Manitoba Hydro November 15, 2022 GRA application. Unfortunately, it therefore appears that the next GRA filing by CGM will be in 2023.

Based on the directional results set out at page 38 of CGM Application under a Coincident Peak allocator, the Power Stations have been underpaying by approximately $571,000 per year and Special Contract has been overpaying by $1,229,000 per year. One of the main beneficiaries of the lag in filing CGM applications to the PUB is CGM's parent Manitoba Hydro.

If the rates only get finalized 3 years later than was reasonably expected in Order 152/19, this may result in the Special Contract subsidizing other classes in the range of $4,000,000 (i.e. 3 x $1,229,000) and CGM's parent being the beneficiary of over $1,500,000 of that subsidization (i.e. 3 x $571,000).

It should also be noted that this Interim measure is also appropriate under the P&A allocator based on the directional results for P&A (Koch/Centra I-2).

Based on the best evidence available, if the PUB were to approve COS in line with the CGM application and the evidence of Atrium, Koch and IGU, reverting back to the pre 2019/20 rates on an interim basis will still mean that Koch is significantly subsidizing other classes of ratepayers.

Centra proposes an interim rate correction that affects only the Special Contract and Power Station classes. Only CAC opposes the Interim Correction – even though no other rates are increased. The interim rate correction reduces the Special Contract rate to the level of non-gas costs in effect prior to the 2019/20 GRA.

As stated in the testimony of witness Collins[64] [footnotes removed]:

> The Interim Measure proposed by Centra is appropriate as a partial, but immediate correction to the unwarranted increase imposed in the 2019 GRA. The $838,000 reduction is only 68% of the reduction which appears to be required to achieve parity with cost of service ($838,000 ÷ $1,229,000) but does reverse the increase to the Special Contract Class in 2019/2020 GRA. To put this into perspective, Koch has been paying an approximate $70,000 per month overcharge since the increase was imposed in the 2019/20 GRA. The Interim Measure would correct this overcharge without increasing rates to other customers. It should be noted that the entire overcharge with respect to cost, as shown in Centra's filing is more than $100,000 per month. The current basic monthly charge to Koch is $187,693. The monthly charge would be reduced to $117,847 when the interim proposed rates are approved. The cost based monthly charge would be $85,241. The remainder of the overcharge should be corrected as soon as possible

The interim relief is just and fair, equitable and appropriate. The interim relief is allowed by the scope of issues set forth by the Board in this proceeding. It is recommended that this Interim rate measure be approved in this proceeding.

[64] Koch Exhibit 3, pdf page 11 of 33.