MANITOBA HYDRO PUBLIC UTILITIES BOARD

IN THE MATTER OF Centra Gas Manitoba Inc. 2021 Cost of Service Methodology Review

REBUTTAL EVIDENCE OF CENTRA GAS MANITOBA INC. ("CENTRA")

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

Darren Rainkie and Kelly Derksen on behalf of Consumers' Association of Canada ("CAC") - Manitoba Branch;

Patrick Bowman on behalf of the Industrial Gas Users ("IGU");

and,

Brian C. Collins on behalf of Koch Fertilizer Canada, ULC ("Koch");

June 30, 2022

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1.0 OVERVIEW

Centra's Rebuttal Evidence addresses the written evidence filed on behalf of the following parties with respect to Centra's 2021 Cost of Service Methodology Review:

- Darren Rainkie and Kelly Derksen (collectively "CAC Consultants") on behalf of Consumers' Association of Canada ("CAC") - Manitoba Branch;
- Patrick Bowman on behalf of the Industrial Gas Users ("IGU"); and
- Brian C. Collins on behalf of Koch Fertilizer Canada, ULC ("Koch").

Centra's rebuttal evidence demonstrates that CAC Consultants confuse consideration of non-cost causal factors with a longstanding policy of "broad" definition of cost causation. Their evidence attempts to draw parallels between Manitoba Hydro's electric and gas operations with respect to the application of cost of service methodologies to support this broad definition. This rebuttal will also demonstrate that Mr. Bowman's conclusions with respect to the Mainline class are also incorrect.

Consistent with the practice of the Public Utilities Board ("PUB" or "Board"), Centra has restricted its Rebuttal Evidence to contradict or qualify new facts raised in Intervener Evidence or to address issues it could not reasonably have anticipated would arise. The fact that Centra does not address or respond to every statement or position taken by interveners in this proceeding should not be taken as Centra's acceptance of such statements or positions.

2.0 COST CAUSATION & POLICY

CAC Consultants provide significant evidence related to their opinions of the definition of cost causation and assesses each of the issues in this proceeding against various definitions of cost causation. They adopt a definition of cost causation that is said to be "broad" and gives weight to how the utility system is designed, planned, and operated or used.[1] In that regard, CAC's evidence suggests that phrases such as "use patterns" or "current use" in previous PUB Board Orders support using average demand (i.e. energy) to allocate demand-related costs, specifically transmission and distribution costs, on the basis that an energy allocator reflects how much customers use the pipeline over the course of a year.

[1] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 13.

However, the term "use" does not equate solely with an energy connotation as suggested. Use patterns of specific customer classes and system operation are equally important concepts when considering which classes contribute to the system coincident peak or design day demand. 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.

Furthermore, closer inspection of Board Order 164/16 says cost causation may refer to how a system is planned or used and gives an example that considers the "utility's most recent planning studies or the planning done to justify assets when originally placed in service". This suggests that "current use" is not an endorsement of a utilization allocator, but rather a recognition that things change and the current role of an asset may be different than what was originally expected.

The fact that cost causation can change over time with changes in circumstances is why the Board's principles of cost causation consider the application of judgement, and refer to current operations and conditions and the acknowledgment that the Board is not bound by prior decisions[2]. Such is the case with the circumstances involving the pipelines directly connected to the Special Contract class and the Brandon combustion turbines. As noted by IGU in the response to CAC/IGU I-1 a), "*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…….That may not be the original reason they were planned or built, but their use has changed.*"

Notably, this approach is consistent with the CAC's identified cost of service principles on pages 17-18 of their evidence filed in the 2015 Manitoba Hydro COSMR which states, "*Utility assets typically have long lives and with changes over time in technology, utility economics, the regulatory environment and government policy, the original intent or driver behind an investment may differ from how the investment is currently used to support the utility's operation and serve customers. While it is useful to consider the original intent of an investment, generally more weight should be given to the current role of investments in meeting customers' service requirements if cost of service studies are to be supportive of rates that signal to customers the costs of continuing to use the utility's services and, thereby, support the efficiency objective." [p.17-18]*

[2] Order 164/16, page 27. Order 107/96, pages 26-27

2.1. Selection of Peak and Average Allocation Method

It is important to distinguish the difference between the definition and application of cost causation and incorporating non-cost causal considerations into a cost allocation study. CAC Consultants have opined that Peak and Average ("PAVG") was implemented in 1996 to reflect a "broader definition of cost causation".[3] However, when the PAVG allocation method was approved in 1996, Centra and intervenors acknowledged that the method was selected in consideration of non-cost casual considerations for determining cost allocation.

A review of the Centra 1996 COSMR transcripts (pages 48-49) and the testimony of the expert consultants makes this point clear:

> *MR. FORAN: What was your understanding of how the cost of service study would be utilized in Manitoba?*
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> *MR. FEINGOLD: R.J. Rudden & Associates understood the practice to be that the cost study should be primarily cost-based, but also that the underlying methodology would explicitly include non-cost causal factors. Second, the end result of the cost study should produce an allocation of revenues among Centra's classes of service that reflected both cost causality and usage of Centra's gas system.*
>
> *MR. FORAN: In summary, what were your principal findings and recommendations?*
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> *MR. FEINGOLD: Our principal findings and recommendations really consisted of four points, the first being that we found that the modified partial plant costing methodology, which is the method that has been used to date by Centra Gas, was overly complicated and did not adequately reflect cost causality. The second point was that we also found that certain other cost allocations utilized within Centra's cost study could be made more accurate or cost reflective. Third, R.J. Rudden & Associates recommended that for purely cost causal reasons the peak day methodology was both the simplest and most appropriate approach.*
> *Finally, 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.*

Although CAC Consultants opine that the PAVG allocator incorporates a broad definition of cost causation in this proceeding and claim the issue of non-cost causal consideration

[3] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 13.

is merely tangential[4], in the 2019/20 Centra General Rate Application these Consultants gave evidence that the PAVG methodology was selected to address non-cost causal factors like equity and fairness.[5]

Overall, cost causation on its own is tied to the design and operational characteristics of the gas transmission and distribution system and is based on the fundamental principle that those who cause the costs should pay for the costs. Whether or not non-cost causal considerations are also factored into the cost allocation process is a separate consideration and as such, does not change or broaden the definition of cost causation as asserted by CAC.

2.2. False Conclusions Regarding Manitoba Hydro's System

Centra notes that PUB Order 164/16 provided direction on Manitoba Hydro's electric operations and as such, it would be incorrect to assume that all considerations with respect to electric plant assets should apply to the gas line of business. As an example, many of the main discussion points at the electric cost of service review were in relation to the large amount of off-system sales and the treatment of large capital-intensive assets – neither of those considerations exist for Centra's gas system. CAC Consultants acknowledged these important differences between electric and natural gas operations and assets and the limitations of making direct comparisons because of these important differences in their direct evidence at the 19/20 GRA. [6]

Despite this, the CAC Consultants attempt to draw several parallels between Manitoba Hydro's gas and electric operations in order to support their advocacy of the Peak and Average methodology and concept of "a broad definition of cost causation" as part of this proceeding. In doing so they draw many false and unsupportable conclusions on Manitoba Hydro's system, which although not directly relevant for making comparisons to natural gas operations for the purpose of this proceeding, are addressed in the sections below.

<u>Top 50 Hours</u>

CAC Consultants state that Manitoba Hydro's demand allocator for electric Transmission reflects a "concerted effort to capture some of the wider range of benefits associated

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[4] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 15.
[5] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page pages 97-98, and 108-109.
[6] Centra 2019/20 General Rate Application, Exhibit CAC-16 Direct Evidence prepared by Kelly Derksen, page 7.

with customer use over time (i.e. energy influence)"[7]. This statement is incorrect. Manitoba Hydro uses the "Top 50" method to determine class contribution to coincident peak for the purposes of allocating bulk transmission costs. The Top 50 method was introduced in the 1995-96 Load Research and is an average of the highest 50 demands at system peak hours. Prior to 1995-96, Load Research used a single CP demand. Selection of only one hour as a peak was not necessarily considered to be representative of all hours in which the peak could occur and may bias the allocation of peak-related costs towards a particular class or classes of service. The streetlighting class, as an example could be off if the peak hour occurred mid-morning, compared to if it occurred in the evening.

The NARUC chapter on Production Plant Costs [8] provides an explanation of why one may want to use demand in a number of hours rather than the single peak hour, while the passage is in reference to allocating demand-related generation costs it is equally applicable to transmission:

"Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation."

Use of the Top 50 hours was determined to be a more representative array of peak conditions – it is not a recognition of an energy influence or "a wide/broad range of operating conditions" as stated by CAC[9] . In reality, the demand in the top 50 coincident peak hours is similar in magnitude but the Area & Roadway Lighting "ARL" class is on in some hours but not in others. Using 50 hours therefore removes the randomness of ARL being on or off during the coincident peak by chance but it is not intended to recognize differences in operating conditions. Notably, both the Coincident Peak Day and Design Day approaches are similar in that they look at a 24-hour period instead of a single hour as incorporated in the Peak and Average Allocator.

<u>Energy Influence</u>

CAC further misinterprets the energy influence of the Top 50 Coincident Peak allocator used for Manitoba Hydro's transmission assets in their response to IGU/CAC I-7. CAC states, *"the top 50 hours are intended to represent the highest peaks and the energy influence would be a function of the consumption at these times in relation to total energy. The top 50 hours are further broadened by averaging these hours over many years."*

[7] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 13.
[8] NARUC Electric Utility Cost Allocation Manual (1992), page 39.
[9] Exhibit No. IGU-9 - IGU/CAC I-5

Based on Manitoba Hydro's most recent cost of service study (PCOSS21) as filed in the 2021 Interim Rate Application, the energy influence included in the Top 50 Hours is calculated below:

	Total General Consumers
CP @ Gen MW (D13/D14)	4,409
Hours in CP	50
Energy used in 50 CP Hours (MWh)	220,431
kWh Generated Adjusted (E12)	25,308,622
Percent of annual energy in 50 CP Hours	0.9%

The electric CP allocator includes 50/8760 or 0.57% of hours, which despite the higher loads in those hours, still represents only 0.9% of annual energy use.

In calculating its Coincident Peak Allocator for demand-related transmission (50 CP) Manitoba Hydro uses eight years of load research, which leads CAC Consultants to claim that the *"top 50 hours are further broadened by averaging these hours over many years".* Some basic math clearly demonstrates that this claim is incorrect:

- 50 peak hours over 8 years = 400 total peak hours
- 8760 annual hours over 8 years = 70,080 total annual hours
- 400 / 70,080 = 0.57%

The eight years are not summed but rather are averaged. As a result, including more years does not broaden the hours included or increase the purported influence that energy has on the allocation of costs. Using a CP based on the average of eight years instead of a single year captures the same percentage of total hours (0.57%), and the share of annual energy consumed in those hours is still 0.9%

Manitoba Hydro uses multiple years of load research to provide a measure of weather normalization in the estimate of class CP demand compared to using a single year. This concept is similar to using the three years of historic peaks to develop the peak portion of the Peak and Average allocator (i.e. Centra's illustrative Coincident Peak Allocator).

Manitoba Hydro Generation

In their response to PUB-CAC I-1, CAC Consultants correctly state that Manitoba Hydro's generation (including Bipoles) and U.S. interconnection assets are classified on the basis of system load factor. However, they further opine incorrectly that the split between demand and energy is nearly equivalent.

The current split between energy (61.4%) and demand (38.6%) is not nearly equivalent – the energy share is actually 160% of the demand share. CAC Consultants also state that Manitoba Hydro's approach that recognizes the dual demand and energy cost drives equates to a "broad-based" definition in attempts to rationalize and support the continued use of a PAVG allocator for Centra's demand costs. Simply put, recognizing the dual demand and energy cost drivers is not some broad-based view of cost causation misconstrued by the CAC consultants, it is the fundamental basis of any generation cost allocation approach that reflects cost causation.

<u>Bipoles and US Transmission Interconnections</u>

CAC Consultants also correctly note that Manitoba Hydro's cost allocation methods for its Bipoles and U.S. Transmission Interconnections are allocated based on both Demand and Energy.

In the case of the Bipoles, their functionalization as Generation and allocation based on Energy as well as Demand reflects that these assets are fundamental to Northern Generation. As noted by the PUB in Order 164/16, "Bipoles I, II, III should be functionalized as Generation as they connect northern generation with southern load centres, acting as extensions of the northern generating stations." The treatment of U.S. Transmission Interconnections is in recognition that the PUB found that the interconnections provided the same benefits as those provided by generating stations. Because Manitoba Hydro's generation fleet is classified as both demand and energy so too are the assets that serve similar roles.

In both cases, the cost allocation methods chosen were based on cost causation that recognizes the roles these assets play in Manitoba Hydro's system. They were not implemented in order to introduce non-cost causal considerations at the cost allocation stage, as was the case with Centra's Peak and Average allocator.

3.0 ALLOCATION OF DEMAND-RELATED COSTS

3.1 Interruptible Class

CAC Consultants incorrectly state that Centra's application suggests that "issues" with the interruptible class are eliminated.[10] Centra's proposal to include Interruptible customer class in the calculation of the Coincident Peak allocator reflects the fact that Interruptible customers are included in the downstream planning process and are not curtailed for downstream reasons. As a result, from a cost causation perspective their load drives costs on Centra's transmission and distribution system the same way as any other load. It is for this reason that Centra has proposed to include them in the Peak Day / Design Day allocator for downstream demand related costs.

None of Centra's proposals are being driven by the Interruptible class – i.e. the "tail wagging the dog" as claimed by CAC in response to PUB-CAC I-3b. Atrium's recommendations looked at the costs of the Centra system, made an assessment of the cost drivers and then recommended the allocation method that in their view best reflected cost causation. Centra's proposals then similarly assessed the recommendations of Atrium and determined based on the characteristics of the Interruptible class and the way their load is considered in Centra's planning processes whether or not particular costs should be allocated to that class.

3.2 Design Day

For the purposes of allocating demand-related Transmission and Distribution costs Centra's illustrative results use the existing Coincident Peak allocator (developed for the Peak portion in the PAVG allocator) in lieu of the current Peak and Average allocator. Should the PUB approve this change in methodology, as noted in PUB/CENTRA I-9 a) Centra commits to developing a Design Day allocator for its next GRA.

In reviewing the evidence of Mr. Bowman as well as the response to PUB/IGU (Bowman) I-2, it appears as though some clarification is required regarding the development of the Design Day allocator. In response to PUB-CENTRA I-9 d) Centra stated, "*The Design Day approach described in part a) will be developed in conjunction with the approved load forecast for the test year and will ensure consistent assumptions by class across all allocators.*" It appears this may have been misinterpreted to mean that the Design Day allocator would be constrained to the peak day associated with load forecast in a given year and therefore not reflective of Centra's planning process. However, Centra's

[10] Exhibit No. PUB-10 - PUB/CAC I-2 a).

response was intending to convey that the Design Day should incorporate the customer class make up, class growth (or reduction), and load growth (or reduction) that is being forecast for the test year. In contrast, the design hour that is used for the purposes of distribution and transmission pipeline capacity planning is done at a localized level (i.e. each pipeline system with an interconnection to the TCPL mainline is looked at in isolation) rather than at a system level (i.e. Centra's entire transmission and distribution system as a whole) and therefore is not necessarily reflective of the overall expected changes in class load that is inherent in the load forecast of the test year.

In their evidence, CAC states "*by attempting to arrive at a pseudo maximum design day determination[33], that appears to consider an average of multiple years of peak data and applying it to an unclear maximum day or peak hour, Centra is simply undermining its desire for a methodology that is purely cost-causal*"[11]. 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). Furthermore, 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.

3.3 Direct Assignment

CAC's evidence asserts that *"Centra's position is unclear on whether Centra is proposing to both direct assign transmission plant as well as a general allocation of remaining transmission plant using a CP allocator"* [12]. In the responses to CAC/CENTRA I-11 e) & f) Centra has provided the steps that were taken to develop the illustrative results of its proposals for the Special Contract and Power Station classes including which cost items are being proposed as direct assignments and which ones it is proposing to continue to allocate.

[11] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 25
[12] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 40

In their response to PUB/CAC I-15 a) & b), CAC incorrectly suggests that it is Koch's location that makes Centra's proposal plausible and therefore the approach is inconsistent with Centra's overarching postage stamp rate philosophy.

Centra contends that it isn't Koch's location but rather the nature of their service requirements that make the approach possible. Koch requires non-odorized gas and high-pressure service. Given the specialized needs of the customer, direct assignment of this type of plant would most likely be plausible in any location.

CAC Consultants also state that direct assignment to Koch and the Power Stations as proposed would conflict with "fundamental tenets of utility ratemaking" in part because "Koch has been receiving the benefit of a reduced cost allocation as a result of the rural expansion contribution adjustment approved by the PUB in Order 118/99".[13]

The PUB summarized the issue posed by the rural expansion program as:

"In short the issue is that customer classes, not included in new expansion areas, bear a portion of all expansion related costs, in accordance with the approved cost allocation methodology. However, if only SGS and LGS customer classes are attached in these new expansion areas, all revenues are allocated only to these classes."[14]

As set out in PUB/Centra I-13(a) Attachment, the rural expansion contribution adjustment was designed to keep customers not participating in the rural expansion (i.e. non SGS and LGS customers) from financially supporting the expansion projects. Centra does not view the historic receipt of this adjustment as a barrier to the adoption of direct assignment – the adjustment is not "a benefit" but rather an appropriate mitigating offset to a cost deemed not to be attributable to Koch.

3.4 Storage and Related Pipeline Capacity

Rate Base Treatment of Gas in Storage

IGU's evidence recommends the cost of gas in storage included in rate base be functionalized as Storage, classified to Demand and allocated using WINTEXC. The use of storage follows a cycle — in the months of April through October the demand for natural gas is considerably lower than in the winter. Centra uses these months to fill storage capacity, allowing the storage reserves to be drawn on from November through March to

[13] Exhibit No. PUB-10 - PUB/CAC I-15 a) & b), page 41.
[14] PUB Order 118/99, page 18.

ensure that energy is there to meet heating needs throughout the winter season. In addition, using storage reduces how much gas is bought in winter when demand is higher and market prices may also be higher. This “smooths” purchases over an entire year and can contribute to rate stability for customers. As it is winter usage that drives costs associated with storage, a refinement to Centra’s current approach that uses annual volumes is reasonable. However, given that it is the cost of the commodity held in storage that is included in rate base (rather than the capacity associated with storage) in Centra’s view it is more appropriate to functionalize the costs as Storage, classify as Energy and allocate using winter volumes.

<u>Winter Demand in Excess of Summer Demand vs Peak and Average</u>

As noted above storage is used to meet heating needs throughout the winter season. The Winter Demand in Excess of Summer Demand 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. While it is correct that idle summer capacity (typically created by the existence of low load factor customers) is used to fill storage, it is done as a means of optimizing the portfolio in a least cost manner – it is not a “benefit” as claimed by the CAC Consultants in their evidence[15]. From a cost causation perspective, use of a PAVG allocator does not recognize the excess cost Centra incurs to serve low load factor customers in the winter.

<u>Treatment of TCPL-STS Costs</u>

Mr. Bowman correctly points out that Centra’s update to Appendix 3 was not consistent with its response to PUB/CENTRA I-15. This was not intentional and Centra can confirm that it is proposing to treat these costs consistent with its proposal for other storage costs such that they would be functionalized as Storage, classified as Demand and allocated using WINTEXC.

4.0 ALLOCATION OF COSTS TO THE MAINLINE CLASS

Section 3.1 of Mr. Bowman’s evidence discusses the relevance of certain aspects of Centra’s distribution system to various customer classes and specifically to the Mainline

[15] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 28

class. It appears however that many of Mr. Bowman's conclusions are based on the notion that Mainline customers are served exclusively at pressures >1900 kPA. This is incorrect and was noted in Centra's reply to IGU/CENTRA I-3 a). As per the Terms and Conditions of Service included as Appendix 2 to the Application and as shown in response to IGU/CENTRA I-3 i), 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.

4.1 Assets Functionalized to Distribution and Allocated to the Mainline Class

Contrary to the evidence of Mr. Bowman, Centra did not confuse what costs are included in account 477.[16] The Power Station and Special Contract customers have dedicated regulating stations, meaning these regulating stations do not serve any other customers, the costs of which are in account 477 and are directly assigned to the respective classes. Some Mainline customers also have dedicated regulating stations that do no serve other customers; the remaining Mainline customers are served through dedicated mains downstream of the Town Border Station ("TBS"). The cost of both the TBS and dedicated stations are included in account 477, only stations attached to the TCPL mainline are included in account 467.

Mr. Bowman is correct that the Mainline class gets allocated a portion of account 477 (excluding stations that exclusively serve the Special Contract and Power Station classes). This is entirely appropriate given that these are assets that are used to serve the Mainline customers. Asset accounting records do not separately identify each measuring and regulating station such that Centra could readily determine the pool of regulating stations that serve the Mainline class.

Regarding Mr. Bowman's statement that the operating and maintenance costs related to station maintenance are redacted in Centra's application, Centra would like to direct Mr.

[16] Exhibit No. IGU-8 - Evidence of Patrick Bowman, page 15.

Bowman to page 11 of Appendix 4. The costs of Regulating Station Maintenance are not redacted and are approximately $5 million.

4.2 Access to the Mainline Class

IGU's evidence unfairly states that Centra has a *"limited interest in aiding availability of the Mainline designation"*[17] by referencing material submitted by Centra in support of the creation of a Mainline class in 1996 and an IR response that was requesting information on literature regarding direct assignment and had nothing to do with the Mainline class designation.

The definition for eligibility as a Mainline customer is set out in Centra's Schedule of Sales and Transportation Services and Rates. The evidence goes on to insinuate, without any foundation, that there are outstanding issues with access to the Mainline class and that the PUB may be required to address disputes. To Centra's knowledge no customers that qualify for the Mainline class have ever been denied access to the class and no customers have requested a special contract. As is the case for any customer, if there is a question about their rate class, Centra encourages them to correspond directly with Centra to discuss their eligibility and the potential bill impacts.

5.0 <u>ALLOCATION OF DEMAND SIDE MANAGEMENT COSTS</u>

In their response to IGU/CAC I-1 a), CAC Consultants correctly state that Centra's current COS treatment recovers the costs associated with DSM from both T-Service and Direct Purchase customers. 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.

6.0 <u>INTERIM RATE RELIEF PROPOSAL</u>

Centra's interim rate relief proposal was to recognize the impact that moving to a direct assignment approach would have on both the Special Contract and Power Station classes. CAC Consultants state their opposition to the interim proposal based on their

[17] Exhibit No. IGU-8 - Evidence of Patrick Bowman, page 16.

determination that *"Centra is placing reliance on an incomplete and outdated set of calculations"* and provides the following observations:

i. Some of Centra's proposed changes have been reflected in the indicative class impacts;

ii. Centra provides proxies for some its proposed changes where additional analysis is required in order to implement the proposed change; and

iii. Some of the proposed changes have not been reflected in the indicative class impacts at all.[18]

However, none of these observations are relevant to the interim proposal. As noted in Centra's application, the interim proposal was to recognize that should the PUB approve the direct assignment approach for the Special Contract and Power Station classes it will result in significant differences in the costs allocated to the respective classes. The approach was never purporting to be based on anything other than illustrative results and was not attempting to be representative of the other possible cost allocation changes.

CAC Consultants imply that there may be an impact to other rate classes "in the longer term".[19] No evidence was provided to support this assertion, and it is unclear to Centra how CAC consultants came to this conclusion. Given that the direct assignment approach will result in more stable cost allocations to the SC and PS classes in the future and that the interim relief can be implemented without affecting other customer classes Centra is of the view that the interim measure is reasonable. Furthermore, Centra notes that the PUB acknowledged the fact that only indicative allocation results were available and ruled the issue to be nevertheless in-scope.

[18] Exhibit No. CAC-8 - Evidence of Darren Rainkie and Kelly Derksen, page 44.
[19] Exhibit No. PUB-10 - PUB/CAC I-16 a) - d).