CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Derksen)-1 Reference: Rainkie-Derksen Evidence pp.118-119; Tab 8 Schedules 8.6.5, 8.7.5, 8.8.5; Tab 11 Schedule 11.4.0; IGU/Centra II-12

Preamble:

The heating value margin deferral balances are allocated to each customer class based on each class's share of the total volumes, but that does not appear to be the basis for the accrual of the margin deferral balances, as the unit (per m^3) margin deferral differs for each class. For example, the Special Contract class is allocated a substantial share of the margin deferral balance but does not contribute to the balance by the nature of its rate design.

Request:

a) Provide an illustrative example, similar to the table below, for a single gas year which shows the accumulation of the Heating Value Margin Deferral balance. A constant actual heating value for the entire year may be assumed for this illustration. State any other assumptions necessary for this illustration. Show the percentage class contributions to the total Heating Value Margin Deferral balance.

	Total	SGS	LGS	HVF	ML	Int	SC	PS
Annual Volume (10^3m^3) [IGU/Centra II-12 Att.]								
Heating Value Revenue Deferral								
Heating Value Cost Deferral								
Heating Value Margin Deferral								
% Contribution to Total Margin Deferral								
Allocated Deferral Balance [IGU/Centra II-12 Att.]								
% of Allocated Margin Deferral [IGU/Centra II-12 Att.]								

b) Provide Ms. Derksen's views whether the allocation of Heating Value Margin Deferral balances could or should be changed to reflect the basis for the accumulation of the balances. Would such an approach be preferable to Christensen Associates' recommendation to simply exclude the Special Contract class from participation in the Heating Value Margin Deferral account? Are there other methods that would more closely align the basis for the accumulation of the Heating Value Margin Deferral balances with the disposition of these balances? If so, please provide.

Response:

Response to parts a and b:

The illustrative example cannot be completed as the WACOG data required (and other data) is not available. Given the differences in WACOG by class, any simplifications could produce results that are unreliable.

That said, at the conceptual level, it is unclear whether the requested illustration would produce results that are more cost causal than an allocation that excludes the Special Contract Class or one that absorbs differences in heating value in net income (the elimination of the heating value deferral). Cost causation related to heating value deferral is tenuous. Narrowly viewed, the requested illustration appears to better align cost responsibility with those who cause the costs – as it would allocate cost responsibility based on the accumulation of the deferral rather than the current treatment which allocates the deferral based on all actual volumes by class. However, the illustrative example does not consider the contribution made to actual heating value content flowing from volumes of gas delivered to the Manitoba border from the Special Contract Class, other T-Service customers, or demand billed customers. And, it is not likely possible or practical to attempt to break out of the commingled gas delivered to Centra's primary gas stations, the Special Contract Class or other T-Service customer's contribution to the actual level of heating value content. On this basis and in recognition of the Special Contract Class's fixed rate structure without a demand rate, it is not likely grossly under allocated cost responsibility from the alternative option of excluding this class from heating value deferral cost. The elimination of the heating value deferral is conceptually appealing in that it is more consistent with Centra's status as a Crown-owned regulated utility as discussed in our evidence (page 119), but it too has drawbacks including that it may not be supported by the utility.

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INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Derksen)-2 Reference: Derksen Evidence p.115

Preamble:

Ms. Derksen states: "*To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered.*"

Request:

a) Please explain how such a deferral mechanism would function, addressing as the following questions:

- What would be deferred – costs or the collection of revenues?
- Would a portion of the recent transmission investments be deferred from rate base? For how long?
- Would the costs be deferred from the calculation of the overall revenue requirement (i.e. depreciation and finance expense)?
- For how long should the deferred costs be amortized?
- Which classes are considered participatory, as all classes participate in the transmission function?
- If the proposed deferral is that of expected revenue, from which classes is it targeted?

b) Please explain whether and how carrying costs related to the deferred costs would be addressed.

Response:

Response to parts a and b:

Generally, the simpler the approach, the easier it is to implement, understand, and administer which correspondingly will minimize the cost.

The initial thinking is that it is not advisable to defer transmission-related rate base or the associated annualized cost through depreciation and finance expense as all customer classes are then impacted and there will be ripple effects of cost allocation also impacting the allocation of O&M and Net Income etc. which adds to the complexity. A deferral option, if adopted, should likely be limited to those classes most greatly impacted such as the Special Contract Class, perhaps other large volume classes – to minimize the administrative impacts and cost. It is not expected that the SGS Class participate.

For the classes that participate, a portion of their class revenue requirement flowing from the 2019/20 Cost Allocation Study could be captured in a deferral including carrying costs and disposed of through a rate rider for that class - over a 5 year period.

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Derksen)-3 Reference: Derksen Evidence p.108, 109; Order 164/16

Preamble:

In 2016, the Board conducted an extensive proceeding to review Manitoba Hydro's Cost of Service Study methodology, culminating in Order 164/16. In this Order at page 27, the Board placed emphasis on the principle of cost causation:

"*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."*

With respect to the allocation of electric Transmission costs, at page 62: "*For domestic AC and interprovincial transmission lines, the Board finds that these costs should be classified as 100% Demand and allocated on the basis of Winter Coincident Peak, based on the domestic load in the top 50 winter hours… A 100% Demand classification is appropriate because the sizing and resulting cost of AC transmission lines is directly related to their ability to meet demand.*"

With respect to the allocation of electric Subtransmission costs, at page 69: "*The Board finds that Subtransmission should be classified as 100% Demand and allocated by Winter Coincident Peak. This reflects cost causation, as Subtransmission planning and operations are similar to Transmission, which is also classified and allocated on this basis.*"

Centra's cost allocation methodology allocates Transmission investment using the Peak and Average allocator, which Ms. Derksen describes as both cost causal and non-cost causal.

Request:

a) If the principle of cost causation was paramount in Centra's cost allocation study, and other ratemaking goals were to be considered at the rate design stage, what would be the most appropriate approach to allocate Transmission costs? What other accommodations would be required in order to incorporate the most cost-causal approach into the cost allocation methodology.

b) Is it appropriate to draw analogies to Manitoba Hydro's Transmission and Subtransmission functions when considering the appropriate allocation of Centra's Transmission costs? If not, explain what distinguishes the function and operation of the electric Transmission system from the gas Transmission system.

Response:

a) While consensus generally exists that cost causation should underpin a cost allocation methodology as it is viewed to be fair that customers pay for the facilities and services they use, the meaning of cost causation is contentious and divergent views generally occur. It is important to note that while the PUB concluded that cost causation is to be a paramount consideration in cost allocation in Order 164/16 (page 27), it was not determined to be the sole consideration. The PUB concluded that it also considers "use" in its definition of cost causation:

> *"Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the **current use**".* Emphasis added.

On this basis, Centra's current cost allocation methodology that allocates transmission investment based on peak and average is appropriate and consistent with recent PUB pronouncements related to cost allocation.

That said, there are other reasonable cost allocation methodologies that could be considered in the allocation of transmission-related capacity investment as well as the capacity-related component of distribution and upstream fixed transportation and storage costs. These will be considered in detail at a future cost allocation proceeding. Briefly, the use of coincident peak ("CP") is a common approach in the allocation of transmission-related capacity cost. This approach may be applied across all capacity-related investment of a utility if the degree in distinction in planning and operation characteristics of the utility are fairly uniform, similar to Centra's current approach. This methodology allocates capacity cost on the basis of each class' volumes at the time of the system peak, measured over a 24-hour period for a gas utility. It is important to note that there are a number of derivations of the CP allocator, the outcome of which can measurably impact cost responsibility by class and is an important consideration. The derivation of the CP allocator can range from each class' contribution to a single maximum peak day to a CP allocator whereby coincident peak is defined over a range confined to the winter periods or even a broader range of peak periods that considers all seasons. The derivation of the CP allocator should match the operational use of the asset costs it is allocating. A methodology that classifies 100% of demand-related costs on the basis of each class' contribution to a single CP may be an especially onerous combination resulting in zero demand-related cost responsibility being borne by some classes (such as interruptible, grain dryers, and asphalt plant customers) despite their heavy use throughout the year. On the other hand, CP allocator that considers a broader range of peak periods is often used and gives recognition to the year-round usefulness of an asset which could accommodate such inequities that might otherwise occur with certain customers (classes) with the reliance on a single CP. From a cost of service perspective, demand accumulated over time looks a lot like energy and would recognize the dual functions that plant often performs. These kinds of considerations would require evaluation and depending on the derivation of the CP allocator, may not result in material differences class cost responsibility compared to the current methodology.

A more aggressive approach that allocates capacity-related cost on the basis of a single peak may require the addition of a zone of reasonableness and/or changes to rate design. Evaluation and consideration would also be required to assess this approach for purposes of the allocation capacity-related distribution costs and upstream fixed transportation and storage costs.

b) Yes, absolutely. However, it is recognized that in some cases the analogies will comport well, and in other cases may not. This will be discussed fully as part of a natural gas cost allocation methodology review. Briefly, as discussed above, one analogy that may be drawn is that while the cost allocation treatment of Manitoba Hydro's Transmission investment gives predominant weight to the cost incurred in serving customer demand, it also recognizes the influence of use or energy in its top 50 winter CP allocator. Use or energy is also an explicit factor in the allocation of the cost associated with MH's HVDC bipole transmission. The conclusion to be drawn is that it is important not only to consider how an asset is functionalized and classified, but the derivation of the allocator. Centra classifies transmission investment 100% to demand (but for a few exceptions). On the surface, one might conclude that this treatment is suggestive that transmission investment is driven entirely based on the need to serve a customer's peak demand. However, clearly the peak and average allocator gives weight to the costs incurred in meeting a customer's average energy needs. Similarly, for MH, while its transmission investment (AC) is also allocated 100% as demand, its top 50 winter CP allocator considers the cost incurred in meeting a customer's energy needs also.

PUB/CAC (Derksen) – 4 Reference: Derksen Evidence p.115

Preamble:

Ms. Derksen states: "*It is Not Appropriate to Make One-Off Fundamental Changes to the Centra Cost Allocation Methodology in the Absence of a Full Methodological Review*".

In prior GRAs, Centra has made changes to its cost allocation study methodology. In the 2013/14 GRA, Centra amended the cost allocation methodology with respect to the allocation of DSM amortization expense, functionalizing this expense as Transmission and classifying it as energy-related (previously it was functionalized as On-site and classified as customer-related). In the 2009/10 GRA, Centra amended the cost allocation methodology by introducing the Fixed Rate Primary Gas Service class.

Request:

a) Provide the threshold for what Ms. Derksen considers to be a fundamental change to the cost allocation methodology, compared to a non-fundamental change.

b) Provide some examples of unintended consequences that can arise when fundamental changes are made to cost allocation study methodologies.

Response:

a) There is no list to rely on for changes considered to be fundamental to cost allocation methodology. The threshold tends to be based on judgment and experience of the cost analyst. As part of Manitoba Hydro's Electric Cost of Service Review in 2016, Mr. Harper provided a great analogy. He described fundamental changes to cost allocation methodology as pulling on a pill of a sweater causing it to unravel and being left with a pile of yarn. Changes that result in the methodology no longer being cohesive or working as a whole or result in a change to the spirit and intent of the methodology would generally be considered fundamental. Fundamental changes can also reasonably be viewed in the context of materiality or contentiousness. For Centra, examples include the treatment of transmission and distribution plant (classification and allocation), postage stamp ratemaking (a matter of public policy), how (and which) ratemaking objectives are reflected in the ratemaking process, and a zone of reasonableness (both its application and range). The addition or elimination of a customer class may also be considered fundamental in some cases. Changes in methodology related to DSM could be significant – for example, past directed treatment of DSM-related cost for Manitoba Hydro's electric cost of service was fundamental given these costs were tied to export revenue, had a material impact on the results of cost of service, and was contentious. For Centra, however, changes in the treatment of DSM, in the view of CAC's independent experts, would not likely be considered fundamental and more a "house keeping" kind of change.

b) There are numerous examples of unintended consequences, several of which include:

- The movement away from or modification to the peak and average methodology in the allocation of capacity-related costs with no corresponding change to consider some customers (classes) avoidance of a contribution to these costs despite their significant usage;

- A methodological framework that is no longer uniform (cohesive) and differs by customer class. This could include postage stamp ratemaking for some classes but not all, or in the case of Manitoba Hydro electric cost of service, a methodological framework that views Manitoba Hydro's system as isolated for the treatment of some costs and interconnected in other cases; and
- The proposed change in balancing fees as discussed in response to Centra/CAC I-6.

PUB/CAC(Derksen)-5 Reference: Derksen Evidence p.122; Order 118/03 p.16,25,79

Request:

a) Please confirm whether the minimum gross margin amount was previously incorporated into Centra's cost allocation studies. If confirmed, did the minimum margin guarantee lower the revenue requirement to be recovered from other classes? If not confirmed, were other classes' rates set higher than necessary for Centra to achieve the Board-approved net income of $3 million?

b) The Power Station class customers have been the subject of the minimum margin guarantee for ten years, three true-ups including provisions for additional contributions, and the original contribution was in excess of the construction costs. Does Ms. Derksen have any concerns that the Power Station class is currently being unduly subsidized by other customers? If so, how should this concern be addressed?

Response:

a) No, the minimum margin was not reflected in Centra's cost allocation studies. The minimum margin guarantee was put in place for purposes of financial feasibility, not cost allocation purposes. The minimum margin guarantee was intended to secure the level of contribution received by the Power Stations in 2003. At the time of the preparation of the financial feasibility in approximately 2003, there was considerable uncertainty related to what revenues to expect from the Power

Stations given their highly variable use profile. In other words, the customer paid a contribution at the time which reflected a minimum of approximately $1.0 million in each year of the 10-year term.

Cost allocation for the Power Stations was determined based on long-standing cost allocation methodology and practice based on their load profile. On an overall basis this is suggestive that other classes' rates were not set higher than necessary.

However, there is a fair amount of movement in the load forecast of the Power Stations as demonstrated in evidence, which is not only causing volatility in its class revenue requirement, but also impacts the allocation of costs to all customer classes. This is a matter of stability in results of cost allocation which is used explicitly in the determination of class revenue requirements (unity). Secondly, the current rate structure of the Power Stations provides for no margin certainty. Currently, if this class were to become fully operational, any margin benefits would hit Centra's net income and retained earnings and would not explicitly be available to Centra's other customer classes. The impact to other customer classes on account of cost allocation and rate design is greater in the absence of the minimum margin guarantee that should be available in light of the PUB's prior direction and given that the true up associated with financial feasibility has concluded. The recommendation is to allow the minimum margin payable by the Power Stations to provide some benefit to other customer classes on an interim basis while the cost allocation and rate design matters are addressed. This is simply an interim measure – it is not advised that the minimum margin continue in perpetuity as it was put in place to serve a different purpose. It is more appropriate to address the cost allocation associated with the Power Stations load volatility and to fully link cost allocation and margin certainty through modification of the Power Stations rate structure.

b) It is important to avoid comingling the concepts of financial feasibility with cost allocation, rate design and rate-setting. The feasibility test and the cost allocation study serve two different purposes.

The financial feasibility test is intended to determine whether revenues generated through the addition of a new customer/load are sufficient to cover the incremental costs incurred in serving that new customer/load over a 30-year period (with the added requirement that the revenue to cost ratio of the project reaches 1.0 by the end of the fifth year). If the revenues are not sufficient, a contribution is collected from the customer.

The cost allocation study, on the other hand, considers revenues (including contributions) and costs of a single test year by customer class.

As discussed in response to Centra/CAC-I 2, it is unclear the results of the 10-year true-up of the Power Stations financial feasibility considering the minimum margin guarantee, three true-ups including provisions for additional contributions, and the original contribution which was in excess of the construction costs. To the extent that true-up has been completed, it is assumed that the obligations of financial feasibility have been satisfied and neither the Power Stations nor other customers overall are unduly impacted.

The cost allocation and rate design matter raised is a separate and unrelated matter to be addressed as discussed in evidence and above. This matter is about the Power Station's contribution to embedded cost of Centra's system, volatility in their load and consequently, impacts all other customer classes, rather than the incremental cost incurred to serve the Power Stations addressed through financial feasibility.

PUB/CAC(Derksen)-6 Reference: Collins Evidence p.10, 13; Derksen Evidence pp.112-114; Order 164/16 pp.60,62

Preamble:

Ms. Derksen appears to take the position that it is not appropriate to discretely identify the assets and their costs that serve the Special Contract class. In his evidence, Mr. Collins' states that there are facilities that can be identified that serve the Koch plant and he recommends that the costs of these facilities be directly assigned to Koch.

Order 164/16, which specifies the cost allocation methodology for Manitoba Hydro's electric operations, directly assigns the costs of radial transmission lines that serve specific customers in the General Service Large >100kV class to that class.

Request:

a) Does Ms. Derksen agree that direct assignment of the costs of assets that can be discretely associated with a single customer or a single class is appropriate, for example with the >100kV radial electric transmission lines that serve certain Manitoba Hydro customers in the GSL >100kV class? If not, explain why not.

b) In the case of the facilities identified in Mr. Collins' evidence that serve the Koch plant, provide Ms. Derksen's view of the appropriateness of directly assigning the costs of these facilities to the Koch plant.

Response:

Response to parts a and b:

Generally speaking, yes. Cost causation is a fundamental goal in cost allocation and to the extent that costs can be identified as belonging to a customer or customer class, to the extent practical, those costs should be direct assigned.

However, direct cost assignments are often limited to the cost associated with equipment located on the customer's premise. Most costs incurred by a utility in the provision of service are common. As discussed in evidence, assets that are "fungible", meaning that today a line serving one customer at any time is easily modified to attach another customer, are generally treated as a common cost. Assets must also be discretely identifiable as serving only one customer (or class). In the case of the transmission assets serving the Special Contract Class, in the event that this customer was no longer served or the assets were abandoned, given the interconnection in serving other customers in that area, modifications to the infrastructure serving these other customers would need to be made. The argument, therefore, that the assets serving the Special Contract Class are discrete and solely serving this customer is tenuous at best. On this basis, in the view of CAC's independent experts, it would not be appropriate to directly assign the costs of these transmission facilities to the Special Contract Class.

The treatment of radial (one way) transmission facilities for cost allocation purposes is also subject to judgment. The reasonableness of the direct assignment of radial transmission facilities rests more on solid ground given its isolation and given the remaining transmission system is largely unimpacted in the absence of these facilities (that is, radials are not interconnected).

PUB/CAC(Rainkie)-10 Reference**:** Rainkie-Derksen Evidence Section 1.3 p.7 line 34; Power Station Minimum Margin Guarantee

Preamble:

Mr. Rainkie recommends that the "*PUB re-establish the Power Station minimum margin guarantee of approximately $1 million, consistent with the PUB's direction in Order 118/03, which should be included in other income for rate-setting purposes to allow for all customer classes to benefit from the reduced non-gas revenue requirement*."

In Order 118/03 the Board stated on page 81:

"*The Board acknowledges that the contract provides for a minimum revenue guarantees, but only for the respective contract terms. The Board will require that any changes in terms and conditions, or extensions to the term of contract will be filed with the Board for review and, if necessary, approval. The Board also expects that the minimum guarantee will continue for any extended contract terms*."

Centra has indicated in response to PUB/Centra I-138 (b)&(c) the minimum Annual Gross Margin amount is only applied to the initial term of the contract, which was ten years. The last year to which the Minimum Annual Gross Margin Amount applied was August 2012 to July 2013.

Request:

Please indicate what, if any, consideration should be given for prior periods as the minimum margin guarantee has not been included in revenue requirement since the expiry of the initial ten-year term.

Response:

With a six-year lag between applications, Centra's current general rate application is long overdue. It is inevitable that these kinds of issues materialize with such a delay and reinforces the need for more frequent and regular general rate reviews. That said, it is the view of CAC's independent experts that focus is best placed on the current test year with a view to the future. Such a view will also avoid complexities that may arise regarding retroactive ratemaking which is generally impermissible (interim rates are one such exception).

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CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Rainkie)-11 Reference**:** Rainkie-Derksen Evidence Section 5.4 p.35

Preamble:

"It is recommended that the PUB direct Centra to include the cumulative profit adjustment of $15.3 million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate-setting purposes. It is also appropriate to include the plant, accumulated depreciation and depreciation expense for rate-setting purposes. It is fair that customers receive both the costs and benefits associated with all of the IFRS accounting changes including the gas meter exchange accounting change. Gas customers have continued to fund gas meter exchange costs between 2014/15 and 2018/19 (in the rates that were approved in the 2013/14 GRA) and as such should enjoy the associated benefit of the cumulative profit adjustment in the consideration of financial reserves for rate-setting purposes."

Request:

a) Please indicate whether there are any obstacles under IFRS from including in the Centra financial statements and financial reporting the cumulative impacts of the gas meter exchange accounting policy change to allow for "one-set of books" for financial reporting and rate setting purposes.

b) If the cumulative profit adjustment related to the gas meter exchange accounting policy change were set up as a regulatory deferral account, what period of time would Mr. Rainkie suggest be used to amortize the balance of such an account.

c) If the preferred options were not possible, and the cumulative adjustment for the gas meter exchange accounting policy change remained only on Manitoba Hydro's consolidated financial statements, please describe what form and content of regulatory financial reporting would be required to allow the PUB to consider the amount in its regulatory proceedings for rate setting purposes.

Response:

a) The recommendations provided in Section 5.4 of the Evidence where made from the perspective of rate-setting and not based upon an analysis of IFRS standards for financial reporting purposes. CAC did not retain Mr. Rainkie and Ms. Derksen to provide a professional opinion on whether or not it is possible to transfer the cumulative profit adjustment from the Eliminations column of MH's consolidated financial statements to Centra's financial statements under IFRS. This transfer is a financial reporting issue that would have to be discussed and decided between Centra and its external auditors.

However, it is noted that Centra's intent (as expressed in its letter to the PUB on March 10, 2016) was to record this accounting policy change in its own financial statements commencing in 2015/16 with restatement to the 2014/15 fiscal year and it was the PUB's direction (in its response letter of April 4, 2016) that each of the accounting policy changes would be examined for rate-setting purposes at the next gas GRA. The recording of the cumulative profit adjustment in the Eliminations column of MH's consolidated financial statements is partly a function of the requirement to harmonize accounting treatment between MH and Centra but is also partly a result of the PUB not accepting accounting policy changes in Centra's financial statements on an interim basis for rate-setting purposes before an appropriate review at a GRA.

Therefore, the original accounting treatment (Elimination column) resulted in part from direction from the PUB and it would be reasonable for Centra and its external auditors to anticipate that the original accounting treatment would be reviewed and the possibility that it would be adjusted for rate-setting purposes by the PUB in the current GRA. As such, this is a pre-existing situation caused in part by a PUB regulatory directive and it would be expected that Centra and its external auditors would carefully consider subsequent PUB directives from the current GRA in terms of the appropriate financial accounting treatment on a go-forward basis.

b) The principle behind the recommendation that Centra include the cumulative profit adjustment to be part of financial reserves for rate-setting purposes is that the financial position and financial outlook be the same as if this accounting policy change had been directly recorded in Centra's financial statements commencing in 2014/15. Accordingly, it is suggested that an amortization period would be directed by the PUB that closely matches the depreciation rate associated with the capitalization of the gas meter exchange labor, which is understood to be 10 years.

c) If the "preferred options are not possible", is understood as meaning that Centra is unable to (1) directly record the cumulative retained earnings, property, plant and equipment (PP&E) and accumulated depreciation or (2) directly record a regulatory asset and a corresponding increase in retained earnings - in its own financial statements (in these situations the cumulative profit adjustment would remain in the Eliminations column of MH's consolidated financial statements).

In the situation where the preferred options are not possible, it is recommended that Centra include the cumulative impacts of the profit adjustment (retained earnings, PP&E and accumulated depreciation) in all of the schedules of the GRA minimum filing requirements to form part of the revenue requirement calculations for rate-setting purposes as well as the associated cost allocation study for developing rate proposals. In addition, it is recommended that Centra prepare and file an alternate Gas IFF financial scenario that includes the cumulative impacts of the profit adjustment as part of the GRA filing and that Centra would explain in its GRA filing how it has considered this alternate financial scenario in making its proposals for rate changes.

PUB/CAC(Rainkie)-12 Reference**:** Rainkie-Derksen Evidence p.39 Line 23-26

Request:

Given that all O&A is assigned through allocators, please provide how Mr. Rainkie proposes ensuring 1% escalation in O&A costs. (i.e. the constraint put on the amount of costs allocated through ICAM to Centra being restricted to 1% of growth)

Response:

In the event that MH is able to manage its O&A costs within the 1% escalation factor that the PUB found was acceptable for rate-setting purposes on Page 24 of Order 69/19, then there should be a natural flow-through of this level of escalation in the O&A costs that are allocated to Centra through the ICAM. In this case, there would be no requirement for a discrete rate-setting adjustment.

In the event that MH is unable to manage its O&A cost within the 1% escalation factor, then a discrete adjustment to the O&A costs that are allocated to Centra through the ICAM would have to be made for rate-setting purposes. This adjustment could be made in a manner that is consistent with the calculations provided on pages 47 to 49 of our Evidence, by considering the level (percentage) of escalation inherent in the MH consolidated O&A forecast and making a corresponding adjustment down to the 1% escalation level, based on the total O&A costs allocated to Centra.

PUB/CAC(Rainkie)-13 Reference: Rainkie-Derksen Evidence p. 52-53

Preamble:

Based on the referenced analysis there are no recommendations for rate-setting adjustments as a result of the information on the record associated with the ICAM, with the exception of the issues and recommendations noted in Section 6.3 with respect to O&A. However, there are a number of recommendations with respect to the ICAM review for future Centra GRA's:

1. The PUB should direct Centra to develop a comprehensive ICAM report that can be used to support the allocation of consolidated operating costs and shared costs between Centra and MH, at future gas and electric rate-setting proceedings. This report would document the overall consolidated costs that are allocated to MH and Centra, the detailed basis for costs drivers used, discuss emerging issues and alternative cost drivers considered, with any resulting recommendations for changes to the PUB for rate-setting purposes;

2. The initial ICAM report could be reviewed through a collaborative process of workshops/technical conferences that occur before the next MH or Centra GRA, including PUB staff and advisors and intervenor representatives, with the goal of obtain sufficient information and assurance that the ICAM is an appropriate methodology for a fair allocation of O&A and shared costs;

3. Once the initial ICAM report is accepted as satisfying the intent of the PUB directive, this report should be maintained on an annual basis (much like a Cost of Service Study) and filed with each Centra and MH GRA to support the allocation of O&A and common costs; and

4. If for any reason, Centra is unwilling or unable to develop the ICAM report and continue to pursue this issue through a collaborative process, then the PUB should proceed to once again direct Centra to file a terms of reference for an independent external review, including circulation to intervenors for comments.

Request:

a) Please provide Mr. Rainkie's view on the cost versus the benefit of an external review of the ICAM versus the proposed internal comprehensive ICAM report and process.

b) If an external report were undertaken, would there still be a need for an annual ICAM process as proposed by Mr. Rainkie? Please explain.

Response:

a) As noted on the bottom of page 52 and top of page 53 of the Evidence, the overall benefit of an external review of the ICAM would be a more comprehensive review as an external consultant would have greater direct access to MH/Centra's records, staff and systems as well as the ability to perform detailed testing of allocations and systems in order to express an opinion on the reasonableness of the methodology. As such, an external review is expected to provide a higher level of assurance to the PUB and interested parties that the ICAM is appropriate and reliable for rate-setting purposes.

An external review is expected to cost more as a result of the upfront consulting cost, additional Centra internal costs to facilitate the engagement as well as the cost of the subsequent regulatory review by the PUB and interested parties at a GRA proceeding.

The collaborative review proposed on page 53 of the Evidence is viewed as a practical but effective compromise. It is expected that an appropriate (albeit lower) level of assurance for rate-setting purposes could be obtained through this form of a review, at a lower overall cost than an external review. The added benefit could be a greater understanding of the ICAM by the PUB, its advisors and interested parties by participating in a collaborative review versus relying on an external review with subsequent testing at a GRA.

b) Yes, the need for an annual ICAM report would still be required if an external review was undertaken. The purpose of an initial external review (or collaborative review process amongst Centra, PUB and interested parties) would be to obtain the assurance with respect to the appropriate functioning of the ICAM for rate-setting purposes.

The purpose of annual ICAM report would be to ensure the on-going appropriateness of the ICAM for rate-setting purposes and would support the annual allocation of O&A and common costs between MH and Centra at electric and gas GRA proceedings. After the initial review of the ICAM report, the subsequent reports would become part of the basic minimum filing requirements with the expectation that the amount of review dedicated to the ICAM report on an annual basis would significantly diminish, until and unless there were significant changes to the ICAM proposed by MH or Centra.

PUB/CAC(Rainkie)-14 Reference: Rainkie-Derksen Evidence – Section 7.2 p. 63-64; p. 91-92 Appendix 14-1 Attachment

Preamble:

While the limited information on risk assessment/quantification in the information requests is directionally better than the information in the application, the overall assessment is that it is incomplete and does not provide sufficient information for a comprehensive review of the appropriate level of financial reserves for rate-setting purposes.

It is recommended that PUB direct the consideration of the establishment of a Minimum Retained Earnings Test for future Centra GRA's for rate-setting purposes, based on a comprehensive assessment of risk and required reserve levels. The approach that is recommended is to use the principles and analysis that are developed for MH and apply and adapt that to Centra's circumstances, as necessary. This would include the development of an Uncertainty Analysis model for Centra that would be used as a quantitative tool to guide the consideration of the appropriate level of financial reserves for gas operations, for rate-setting purposes.

Request:

Please discuss what risks the uncertainty analysis for Centra should model.

Response:

Given that the MH Corporate Risk Management Report is focused mainly on its electric operations, an initial step towards the uncertainty analysis for Centra would be the development of a comprehensive risk assessment/analysis by Centra's management that was specifically focused on the most adverse risks facing natural gas operations and their probability of occurrence. The uncertainty analysis would model a combination of the most plausible adverse risk scenarios that are faced by Centra, as well as potential management and regulatory responses, in order to assess the ability of the expected financial reserves to withstand these adverse scenarios while continuing to promote a high degree of rate stability for customers. Examples of risks on the record of this proceeding that may be modelled in the uncertainty analysis include weather, interest rates, customer growth, variations in BOC, O&A and DSM spending, catastrophic system failure and infrastructure risks.

In addition to the uncertainty analysis, the PUB would also likely want to provide rate-setting direction on those natural gas risks that should be built into on-going rate changes, those risks that would be protected by financial reserves and those risks that the PUB would be prepared to deal with through future regulatory response (rate increases when the emergent risks are actually facing Centra rather than being built up in financial reserves through rate increases in advance of occurrence in those risks). For example, In Orders 59/18 and 69/19 related to electricity operations, the PUB found that key risks such as interest rate and export price risks should be built into rates when those risks materialise and not through building up of retained earnings and that drought risk should be managed through a combination of retained earnings and regulatory action when drought is actually facing MH. Similar direction from the PUB would be beneficial in developing an uncertainty analysis and minimum retained earnings test for natural gas operations.