MANITOBA PUBLIC UTILITIES BOARD

CENTRA GAS MANITOBA INC.
COST OF SERVICE METHDOLOGY REVIEW APPLICATION

Evidence Prepared By

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On Behalf of

Consumers' Association of Canada (Manitoba Inc.) (CAC)

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1.0 Executive Summary

The last comprehensive external review of Centra's natural gas COSM and rate design occurred in 1996 (Order 107/96), and the primary aspects of the methodology have remained relatively unchanged since that time.

Based on an external review of the COSM (Cost of Service Methodology) which was completed in 2021, Centra is proposing a number of amendments to its COSM including: (1) replacing the Peak and Average allocator which is currently used for the allocation of demand related costs with a Coincident Peak Day allocator for Transmission & Distribution investment and Year-Round Pipeline Capacity and a Winter Season Demand in excess of Summer Season Demand allocator for storage and related pipeline capacity; (2) utilizing a direct assignment of transmission plant to the Special Contract and Power Station classes; and, (3) indexing the results of the service line study.

The purpose of this evidence is to evaluate Centra's COSMR proposals and provide related conclusions and recommendations. As a result of the scope and information limitations of this proceeding, the evaluation is primarily focused on the policy analysis and the consistency of the proposals with the policy analysis, as well as consideration of the specific circumstances of Centra based on information on the record.

1.1 It is Recommended that the PUB Retain its Policy of a Broad Definition of Cost Causation that Gives Weight to Both System Planning & System Operation/Use

The policy evaluation analyzed the key policy directives that have been articulated by the PUB arising from past COS reviews for both natural gas and electric operations and evaluated the consistency of Centra's COS policy that is driving the proposed amendments, and can be summarized as follows:

1. The PUB COS policy includes a long-standing broad definition of cost causation and has more recently evolved to exclude consideration of other ratemaking objectives from COS;
2. Centra's apparent new policy of a narrow definition of cost causation is inconsistent with the PUB policy and weakens the cohesiveness of the natural gas COSM;
3. Cost causation should continue to be given the most weight in the selection of cost allocation methodologies;
4. The PUB should retain its long-standing policy of a broad definition of cost causation that gives weight to both system planning and system operation and use; and
5. Cost causation should not be a sole consideration, as it is impractical to remove all other ratemaking objectives as they are inherently an important element of developing a cohesive and workable COS framework.

1.2 The Limited Industry Research Indicates that there is Diversity in COS Practice in Canada with a Range of Acceptable Methods and No Singular Industry Best Practice Upon which to Rely for COS Decisions

The completeness and implications of the research that was conducted into the COS practices of the Canadian natural gas LDC's was evaluated, and can be summarized as follows:

1. The industry research is limited in depth and provides no clear insights into the policy drivers and specific circumstances that led to the selection of the COS methodologies by the Canadian natural gas LDC's;
2. It is unclear if the industry research has impacted Centra's review of its COSM and how, if at all, the research supports the Centra COSM proposals; and
3. There is diversity in the COS methodologies used by Canadian natural gas LDC's and specified in authoritative COS literature, with a range of acceptable methods in practise, and no singular industry best practice, upon which to rely for COS decisions.

1.3 It is Recommended that the PUB Retain the Peak and Average Allocator for All Upstream & Downstream Demand-Related Costs

The Centra COS proposals to replace the Peak and Average allocator which is currently used for the allocation of demand related costs with (1) a Coincident Peak Day allocator for transmission & distribution plant and year-round pipeline capacity and (2) a Winter Season Demand in excess of Summer season Demand allocator for storage and related pipeline capacity were evaluated and the results and recommendations can be summarized as follows:

1. There are three generally accepted methods for the allocation of demand-related costs including coincident peak (CP), average and excess (peak and average or PAVG) and non-coincident peak (NCP);
2. Centra's rationale for its proposed CP allocator for demand-related transmission and distribution costs is that it more accurately reflects pure cost causation;
3. Centra's rationale for proposing CP to allocate year-round pipeline costs and the Winter in Excess of Summer Demand for storage & related pipeline costs are unclear and the rationale for conceptually different methodologies for these two components of upstream costs is also unclear;
4. It is recommended that the PUB retain the peak and average allocator for the Allocation of the demand-Related transmission and distribution Investment and the allocation of demand-related upstream year-round pipeline and storage & related pipeline costs – as it better aligns with the broader PUB definition of cost causation and is directionally consistent with how Centra's downstream system is both planned and operated and with Centra's gas supply operations; and
5. The issues associated with the Interruptible Class from Centra's proposals are minimized by retaining the peak and average methodology for the allocation of demand-related upstream and downstream costs.

1.4 It is Recommended that the PUB Retain the Current Classification of Distribution Plant Between Demand & Customer and that Centra Update the Diameter-Length and Service & Meter Studies for its Next GRA

The classification and methods available to determine the split of distribution plant between customer and demand, as well as the current status of the related special studies were evaluated, and the resulting recommendations can be summarized as follows:

1. It is recommended that the PUB retain the current classification of distribution plant between demand and customer as the split between demand and customer aligns with the broader definition of cost causation in accordance with the PUB's COS policy;
2. It is recommended that the PUB retain the diameter-length distribution classification study as a means to estimate the weighting of customer and demand for distribution plant as this methodology is the most commonly used in North American; and
3. It is recommended that Centra update the diameter-length and service & meter studies for its next GRA to ensure that they are providing a reasonable basis for the allocation of distribution plant.

1.6 It is Recommended that Gas DSM be Treated Conceptually Consistent with Electric DSM and Allocated Based on the Peak and Average Allocator

The allocation of gas operations DSM costs, including the consistency with the allocation treatment with electric DSM costs were evaluated, and the results and recommendations can be summarized as follows:

1. Gas operations DSM is currently directly assigned based on class participation, while electric operations DSM is treated as a system resource and follows the allocation of generation;
2. Centra appears to prefer retaining its current direct assignment approach for Gas DSM investment based on its view that there are only minimal incremental economic benefits to the overall natural gas system;
3. It is recommended that gas DSM be treated conceptually consistent with electric DSM, functionalized as transmission and allocated based on the peak and average allocator given that the investment benefits not only the participating classes, but also provides broader system and societal benefits and is consistent with the PUB's COS policy of a broader definition of cost causation.

1.7 It is Recommended that the Special Contract and Power Station Customer Classes Continue to Receive a Broader Allocation of Transmission Plant & that No Interim Rate Reduction be Provided to the Special Contract Customer

The Centra proposals to directly assign transmission plant to the Special Contract and Power Station customer classes and provide an interim rate reduction to the Special Contract customer class were evaluated, and the results and recommendations can be summarized as follows:

1. Utility plant is fungible in that the investment can serve different purposes over time and as such is generally allocated rather than directly assigned to customers classes;

2. Centra's proposal to direct assign transmission plant to the Special Contract and Power Station customer classes is based on the recent evolution of its system configuration;
3. It is recommended that the Special Contract and Power Station customer classes continue to receive a broader allocation of transmission plant (and not direct assignment) as the Brandon/Southwest Area System continues to be integrated under a broader view of cost causation consistent with the PUB's COS policy;
4. It is recommended that no interim rate reduction be provided to the Special Contract customer class as a result of this proceeding, as Centra's customer impact analysis that is relied upon to propose this reduction is incomplete and outdated and such a measure would constitute retroactive ratemaking; and
5. If the PUB approves any changes flowing from this proceeding, it is recommended that Centra be directed to file two COS studies at the next GRA, one that reflects all the COS changes as well as the updated revenue requirements, and one that excludes the COS changes such that the impacts as a result of the COS changes can be isolated and tested.

2.0 Introduction & Scope, Purpose of Evidence

This section of the Evidence provides a brief overview of Centra's COSM Application, the scope and availability of information in this proceeding, the qualifications of Mr. Rainkie and Ms. Derksen and outlines the purpose, scope and organization of the evidence.

2.1 Overview of Centra's 2021 COSMR Application

The last comprehensive public review of Centra's natural gas COSM and rate design occurred in 1996, which resulted in Order 107/96. While there have been some modifications in the natural gas COSM since 1996, the primary aspects of the methodology have remained relatively unchanged since the last comprehensive review.

As part of Order 152/19 that flowed from the Centra 2019/20 General Rate Application (GRA) and in response to a number of concerns raised by Intervenors at that GRA proceeding, the PUB directed that there was to be a comprehensive review of the natural gas COSM in advance of the next Centra GRA[1].

On June 15, 2021, Centra filed its COSMR Application and associated proposals which largely only responded to the issues that were identified at the 2019/20 GRA. The Centra Application also included a report based on an external review conducted by Atrium Economics LLC (Atrium).

There is some ambiguity in the COSMR Application as to the exact nature of the amendments that Centra is proposing which are discussed in the sections of this Evidence that follow. Based on the information requests, it appears that Centra is proposing the following amendments to its COSM in this Application[2]:

1. Replace Peak and Average with a Coincident Peak Day allocation method for downstream capacity costs (transmission and distribution plant), which would include the Interruptible Class;
2. Utilize Direct Assignment of transmission plant to the Special Contract and Power Station classes;
3. Replace the Peak and Average allocator for upstream capacity costs with a Coincident Peak Day allocation for year-round pipeline capacity, which would exclude the Interruptible class;
4. Replace the Peak and Average allocator with a Winter Season Demand in excess of Summer Season Demand allocation for storage and related pipeline capacity, which would include the Interruptible class; and
5. Index the results of the service line study.

[1] Order 152/19, PUB findings at Page 84 and directive 29 at Page 137
[2] PUB/Centra 18 f - g

2.2 Scope & Available Information for the COSMR Proceeding

The original directive flowing from Order 152/19, was such that there was to be a comprehensive review of the Centra COSMR. In a number of subsequent procedural decisions, the PUB clarified that the scope of the COSMR regulatory proceeding was to be much more focused and limited in terms of scope and information that was available to Intervenors to conduct their evaluation/test the COSMR proposals and provide recommendations to the PUB.

In terms of scope, the PUB directed that[3]:

- In-scope issues would be focused on the classification and allocation of downstream transmission and distribution plant, the allocation of upstream capacity costs, demand-side management costs, operations, maintenance & administrative costs, amendments to the COSM for rate re-bundling impacts, elimination of the Co-op class and a potential near-term rate impact measure for the Special Contract and Power Station classes; and
- The out-of-scope issues would include matters of rate design, introduction of a Zone of Reasonableness, customer class rate impacts and the minimum margin guarantee for the Power Station class. These matters would be reviewed at the next Centra GRA.

In terms of information available to Intervenors to evaluate and test the Centra COSMR proposals, the PUB directed that[4]:

- Intervenors would not be provided access to confidential information in the Centra application used to derive the illustrative results of the COSMR proposals and indicative class impacts, as well as the existing or proposed COS models; and
- Issues associated with implementation of any of the COSM proposals that may be accepted by the PUB are not within the scope of this proceeding and are to be reviewed either following a compliance filing flowing from a final Order of the PUB or at the next Centra GRA.

2.3 Overview of Qualifications

Through a joint regulation consulting practice, Mr. Rainkie and Ms. Derksen offer services to a wide range of clients that participate in and are impacted by rate-regulation and regulatory proceedings. In this proceeding, Mr. Rainkie and Ms. Derksen are providing evidence on behalf of the Consumers' Association of Canada (Manitoba Inc.) (CAC).

Mr. Rainkie has over 30 years of experience and expertise in rate-regulation, utility and financial management and specializes in regulatory/ratemaking policy and strategy and revenue requirement and fiscal matters. Mr. Rainkie's full curriculum vitae was attached as Appendix C to the CAC Intervenor Registration submission (Exhibit CAC-1)

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[3] Order 36/22, Pages 13 to 15

[4] Order 58/22, Pages 16 and 17

Ms. Derksen has over 25 years of experience and expertise in energy regulation and ratemaking and specializes in cost of service and rate design matters. Ms. Derksen's full curriculum vitae was attached as Appendix B to the CAC Intervenor Registration submission (Exhibit CAC-1).

2.4 Purpose, Scope & Organization of Evidence

The purpose of the evidence is to evaluate Centra's COSMR proposals and provide related conclusions and recommendations.

Our normal approach in these types of regulatory proceedings, would be to evaluate the applicant's proposals by applying a three-pronged evaluation framework:

- **Policy Analysis**: analysis of the reasons and justifications for the proposals considering applicant policy drivers, regulatory commission policy directives and generally accepted ratemaking principles and objectives;
- **Contextual Analysis**: analysis of the reasonableness of the proposals considering the specific circumstances of the utility and consistency with the policy and principles from the policy analysis; and
- **Implementation Analysis**: analysis of the reasonableness of changes that are necessary to implement the proposals and successfully integrate them into the utility's overall rate-setting framework.

Evaluating and selecting COS methodologies involves the application of considerable professional judgment. For each COS topic, there are a number of broad approaches acceptable in practice and there are also numerous variations of each of the approaches depending on the judgment of the practitioner, the circumstances of the utility, and the availability of data. As such, it is necessary to consider a broad spectrum of policy, ratemaking objectives, utility specific circumstances, and data availability, in order to appropriately exercise that judgment.

The ability to apply a three-pronged evaluation framework is critical to a robust evaluation of any COS proposals. The three sets of analysis compliment and reinforce each other and work together to strengthen the robustness of the overall evaluation of the proposals. For example, testing how a proposal is to be implemented significantly aids in the understanding of the reasons and justifications for the proposals. The implementation analysis not only considers if the proposal can be successfully implemented into the overall rate-setting framework but, also, considers if the policy intent of the proposal has been achieved.

In the current proceeding, Centra's application, Atrium's Report and Centra and Atrium responses to information requests are minimalist in terms of policy and contextual analysis and the implementation analysis and related information has been determined to be out of scope.

As a result of the scope and information limitations of this proceeding, the evaluation of the Centra COS proposals as provided in the subsequent sections of this Evidence is by necessity more limited than might otherwise be the case and is primarily focused on the policy analysis and the consistency of the proposals with the policy analysis as well as consideration of the specific circumstances of Centra based on information on the record. It is recommended for future generic reviews of this type, that the completeness of the filing and information requests and intervenor access to information be broadened to allow for a more robust evaluation of Centra's proposals.

The sections of this Evidence are organized as follows:

- Section 3.0 provides the evaluation that flows from the policy analysis;
- Section 4.0 provides the evaluation of the industry practice research that was conducted by Atrium;
- Sections 5.0 to 8.0 provide the evaluation of each of the key in-scope issues in terms of the consistency of Centra's proposals with the policy analysis and Centra's circumstances. Section 5.0 evaluates the allocation of capacity costs, Section 6.0 evaluates the classification of distribution plant, Section 7.0 evaluates the allocation of demand-side management costs, and Section 8.0 evaluates the direct assignment of transmission plant to the Special Contract and Power Station classes and an interim rate reduction for the SC class.

3.0 Policy Evaluation

As part of the rate-setting process, the PUB has reviewed and provided policy guidance on Manitoba Hydro's electric COSS and Centra's natural gas COSS for many decades. This section of the Evidence begins the policy evaluation by identifying and analyzing the key policy directives that have been articulated by the PUB arising from past COS reviews for both natural gas and electric operations. The policy analysis then proceeds to evaluate the consistency of Centra's COS proposals against the PUB COS policy directives and provides conclusions and recommendations that flow from the evaluation.

The results of the evaluation in this section of the Evidence, can be summarized as follows:

1. The PUB COS policy has included a long-standing broad definition of cost causation and has more recently evolved to exclude consideration of other ratemaking objectives from COS;
2. Centra's apparent new policy of a narrow definition of cost causation is inconsistent with the PUB policy and weakens the cohesiveness of the natural gas COSM;
3. Cost causation should continue to be the primary driver of COS policy and be given the most weight in selection of cost allocation methodologies;
4. The PUB should retain its long-standing policy of a broad definition of cost causation that considers and gives weight to both system planning and system operation and use; and
5. While cost causation is the primary driver, it should not be a sole consideration, as it is impractical to remove all other ratemaking objectives as they are inherently an important element of developing a cohesive and workable COS framework.

3.1 The PUB's COS Policy Has a Long-Standing Broad Definition of Cost Causation & Has More Recently Evolved to Exclude Consideration of Other Ratemaking Objectives

The last comprehensive review of the natural gas COS and rate design occurred in 1996 and resulted in Order 107/96. The following excerpts from Order 107/96, summarize the key PUB policy findings with respect to the last natural gas COS review:

> "The Board will expect such a review to consider the appropriateness of all methods and systems to be employed to functionalize and classify all capital and operating costs and allocate such costs to proper customer class definitions. The Board further expects that the **primary driver** will be **cost causation** with due regard to Centra's current operations in the Manitoba market, direct purchase activities, storage arrangements, risk management activities, **weather** and **use patterns** for each specific customer class and **all other relevant issues.**[5]" (Emphasis added)

[5] Order 107/96, Page 6

"**Cost allocation studies** are **not a precise science** and **contain elements** of **judgement** at **most phases**. Cost allocation methodologies are numerous, and experts often have differing opinions as to the appropriate manner of allocating costs of service. It is the **Board's responsibility** to **weigh those differing views** and to support a methodology which gives the best guideline for determining just and reasonable rates, and which is not unduly discriminatory, recognizing that subjective judgements will influence results...This public hearing was to allow debate of these opinions and to arrive at a methodology which best reflects the Manitoba circumstance...The Board's expectation is that the principles herein approved will be adaptable to industry changes and that the results produced should be acceptable for some time into the future...The Board also agrees that the **cost of service methodology best suited** for a natural gas distribution company should be **determined based upon** the **circumstances** of the **utility**. Those **circumstances must reflect** the **manner** in which the **system is designed as well** as the **manner** in which the **system is operated**. Giving **some weight** to the **manner** of **system operation better reflects** the **cost responsibility than** does a **methodology** which **considers only** the **design parameters**. For example, a system may be designed to interrupt particular customers on a peak day so that firm customers can continue to receive service. Should the peak not be met, however, those interruptible customers continue to receive service...Even though a design contemplates curtailment of interruptible customers, it cannot preclude a movement of customers from firm to interruptible service or vice versa. The Board is of the view that Centra's proposal for the use of demand related cost allocators based on the Peak and Average Methodology best reflects the appropriate treatment for all Manitoba natural gas consumers, that it reflects current market conditions and is adaptable to change.[6]" (Emphasis added)

The last comprehensive review of the electric COS occurred in 2016 and resulted in Order 164/16. The following excerpts from Order 164/16, summarize the key PUB policy findings with respect to the last electric COS review:

"The Board finds that, in the process to **determine** the **appropriate COSS methodology**, the **principle** of **cost causation** is **paramount**...The Board finds that **Manitoba Hydro's ratemaking principles and goals** of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be **considered** in a **General Rate Application** ("GRA") and **not** in the **cost of service methodology**...**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**...The Board also finds that **cost causation requires consideration** of **all** the **uses** and **benefits** of an **asset**, to **recognize** that **both primary** and **secondary benefits** influence the planning and justification of assets. These **considerations** should be **assessed over a range of years** (as opposed to a single

[6] Order 107/96, Pages 26 to 27

forecasted year) and **over** a **range of conditions** in order to **capture all** of the **uses and benefits** of an **asset** in **determining cost causation**.[7] (Emphasis added)

It is observed that there is a significant alignment in the PUB policy perspectives in the last natural gas COS review and last electric COS review, even though they are separated by over 20 years and different PUB member composition. The areas of policy alignment are as follows:

1. The principle of cost causation is the primary driver in developing appropriate COS methodologies;
2. The definition of cost causation is broader than only considering strict engineering design parameters;
3. The broader definition of cost causation in the PUB COS policy should consider and give weight to both how the energy system is designed and planned as well as how the system is operated, used and usage patterns; and
4. The broader 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.

There are numerous examples of how this broader definition of cost causation that encompasses both system planning and system operation and use, are included in the existing electric and natural gas COSM. A few of these examples (and by no means an exhaustive list) include:

- The use of a Peak and Average methodology as approved by the PUB in Order 107/96;
- Centra has long recovered the costs associated with the provision of the WTS from all sales customers on the basis that this service provides benefits beyond only those who elect to participate;
- The functionalization, classification and allocation of electric Bipoles as Generation that recognizes the broader role and benefit Bipoles provide to Generation, despite that the Bipoles are clearly poles and wires, the cost of which is driven by the size of the conductor (demand), and which are treated for accounting purposes as Transmission;
- The PUB found that costs of U.S Transmission Interconnections provide a number of benefits related to both Demand and Energy including supporting domestic load in drought conditions despite that from a strict engineering perspective, cost of these facilities are driven by the size of the conductor (i.e. demand) to serve domestic customers; and
- The PUB found that the costs of AC Transmission for electric operations are incurred 1) to meet higher peak demand; 2) to geographically expand the AC network to serve additional load; and 3) to provide adequate redundancy. Transmission is allocated 100% to Demand and allocated on a Winter Coincident Peak based on the top 50 winter hours. A large number of peak hours (which are averaged over many years) reflects a concerted effort to capture some of the wider range of benefits associated with customer use over time (i.e. energy influence).

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[7] Order 164/16, page 27

It is also noted that there is a more recent change in the PUB policy perspective as part of the 2016 electric COSM decision, as it relates to the application of other ratemaking principles as part of the rate design stage and not in the COS stage of rate-setting.

3.2 Centra's Apparent New Policy of a Narrow Cost Causation Definition is Inconsistent with PUB Policy & Weakens the Cohesiveness of the Gas COS Methodology

Having established the key elements of PUB COS policy in the prior sub-section, the next step in the policy evaluation is to consider if the policy drivers of the Centra COS proposals are consistent with the PUB COS policy.

Unfortunately, the minimalist nature and structure of the Centra COSM filing make this step of the evaluation more challenging than it should be. Atrium clarified in the information request process, that it was not retained to review ratemaking policy matters and did not have any discussions with executive members of Centra in forming its conclusions and recommendations[8]. Centra's COS proposals for the most part adopt Atriums recommendations that were made without consideration of ratemaking policy. The only substantive section of Centra's COSMR Application (Section 4.0) is set up as a response to Atriums recommendations, with very brief statements with respect to Centra's position and rationale on each recommendation. Accordingly, there is a dearth of discussion in the Centra COSMR Application on any consideration of policy matters that led to the COS proposals and how the various proposals impact the overall natural gas COSM.

In an attempt to remedy this circumstance, Centra was requested to provide information on the policy drivers and articulate any changes in circumstances that resulted in its COS proposals. From the information request process, our understanding is that, in Centra's view, the COS proposals are driven by the following policy drivers[9]:

1. A better reflection of "pure" cost-causal principles; and
2. The PUB's more recent views flowing from Order 164/16 that non-cost causal considerations are best incorporated at the rate design stage rather than embedded in cost allocation.

With respect to the first policy driver noted by Centra, it is interpreted that Centra's assertion that its COS proposals reflect a pure definition of cost causation means that Centra has changed its long-standing COS policy that reflected a broader definition of cost causation, that included both system design and system operation and use. It was also interpreted that the utility is now adopting a new policy that involves a very narrow definition of cost causation that is driven exclusively by design and engineering considerations. This policy change is evident in all of the key issues that are before the PUB in this proceeding.

However, when Centra was asked in information requests to explain the changes in circumstances that caused it to reverse this long-standing policy and adopt a narrow definition of

[8] CAC/Atrium 1c

[9] CAC/Centra 1a, 3a, 4a,

cost causation, it stated that it has not reversed it position with respect to the definition of cost causation[10].

Our overall assessment is that Centra's COS proposals are inconsistent with the PUB policy and broader definition of cost causation as outlined in Orders 107/96 and 164/16 and summarized in Section 3.1 above. The reasons for these inconsistencies will be elaborated on in Sections 5.0 to 8.0 of this Evidence. As an example, a design day coincident peak does not consider a broad range of years, operating conditions, primary and secondary benefits "in order to capture all the uses and benefits of an asset in determining cost causation".

Curiously, when this inconsistency was noted in information requests of Centra and Atrium, they provided conflicting responses[11]. Centra indicated that it agrees with the PUB's broader definition of cost causation and asserts that its proposals are consistent with PUB policy[12]. Atrium, in contrast, concedes that its proposals are not consistent with the PUB's findings that "cost causation requires consideration of all of the uses and benefits of an asset to recognize that both primary and secondary benefits influence the planning and justification of assets"[13].

In the responses to information requests, Centra attempted to provide three changes in circumstances that influenced its cost-of-service proposals: 1) Special Contract and Power Stations now being served by dedicated pipe 2) varied and often limited use by the Power Station class and 3) the Interruptible class not being curtailed for downstream purposes[14]. On the one hand, Centra states it has not reversed its long-standing policy on the definition of cost causation. On the other hand, Centra attempts to provide its rationale for its policy change. If Centra does have a policy stance that is driving the proposed COS proposals, it certainly is unclear at best. Further, in our assessment, the changes in circumstances cited by Centra do not rise to the level that would justify a monumental change to its long-standing policy perspective that considers a much broader definition of cost causation.

With respect to the second policy driver noted by Centra, it is unclear which non-cost causal considerations that Centra is relying on to justify its COS proposals. From our perspective, it is clear that it is the definition of cost causation that is the primary contentious issue in determining the appropriateness of Centra's COS proposals. The issue of consideration of non-cost causal factors, consistent with the PUB's direction flowing from Order 164/16, is tangential and more of a practical issue.

Interestingly, while supporting the PUB policy that non-cost causal considerations should only be part of the rate design phase of rate-setting, there are numerous examples in the Centra COSM Application and Atrium Report where they utilize non-cost causal considerations to make COS proposals or recommendations. A few of these examples (not intended to be exhaustive) are as follows:

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[10] CAC/Centra 3a
[11] CAC/Centra 2a b, CAC/Atrium 3c
[12] CAC/Centra 2 a b
[13] CAC/Atrium 3 c
[14] CAC/Centra 3b

1. Centra states its preference for the Winter Season Demand in excess of Summer Season Demand as it is much easier to understand and far less complex to implement than the more costly seasonal resource-stacked based option[15]. In this case, Centra is applying both the ratemaking objectives of understandability and administrative ease as a compromise preference to its rigid adherence to cost-causality;
2. It appears Centra has proposed a work around method to calculate contributions to maximum peak day as it does not record maximum peak day data as the recommended calculation of peak day proposed by Atrium. In this case, Centra is applying the ratemaking objective of administrative ease[16];
3. In proposing a design day demand allocation, Atrium states that this methodology provides stability in cost allocation results more than any other demand allocation factors.[17] Atrium is thus relying on the ratemaking objective of stability to support its cost allocation recommendation; and
4. Recently, Centra proposed, and the PUB approved in Order 131/21, the re-bundling of Primary, Supplemental Firm and Supplemental Interruptible rates. In this case, emphasis shifted away from pure cost causation in favour of administrative ease, customer understandability and bill simplicity.

These observations are not meant to be critical. Developing a workable COSM involves many judgments, considerations, and trade-offs. The point of the observations is to note the inconsistency of the positions of Centra and Atrium.

In addition to the concerns with respect to the inconsistency of Centra's COS proposals with the broad definition of cost causation, there is also concern with respect to the weakening of the overall cohesiveness of the natural gas COSM and inconsistency with the overall electric COSM framework.

The current natural gas and electric COSM that are in place reflect the application of the broader definition of cost causation and have been inherently developed with consideration of a range of ratemaking objectives other than just cost causation.

Centra's COS proposals that adopt a narrow definition of cost causation, on a piece-meal basis for the few in-scope issues, will result in a COSM that lacks overall cohesion, with a mix of different definitions of cost causation. The Centra COS proposals do not result in a natural gas COSM that is more consistent with the electric COSM, as is erroneously asserted by Centra[18].

[15] Centra Application, page 35, lines 4-8
[16] PUB/Centra 9a-e
[17] Atrium Report, pages 13, 14
[18] Centra Application, page 37

3.3 It is Recommended that the PUB Retain the Broad Definition of Cost Causation & Consider Other Ratemaking Objectives in COS

In summary, based on the issues that are assessed in Sections 3.1 and 3.2 of the Evidence, our evaluation of the policy and ratemaking objectives leads to the following conclusions and recommendations:

1. Cost causation should continue to be the primary driver of COS policy and be given the most weight in selection of cost allocation methodologies. This view is consistent with ratemaking policy, objectives and generally accepted ratemaking principles;
2. The PUB should retain its long-standing policy of a broad definition of cost causation that considers and gives weight to both system planning and system operation and use, primary and secondary benefits and uses of assets, as well as a range of years and operating conditions. COS is inherently an art and not a science based on engineering precision and involves the considerable exercise of professional judgment. A broader definition of cost causation will lead to a more robust COSM that is more durable to meet the wide variety of circumstances that are encountered in utility operations. There are no changes in Centra's circumstances that justify a change in policy to a narrow definition of cost causation; and
3. While cost causation is the primary driver of COS policy and selection of cost allocation methodologies, it should not be a sole consideration, as it is impractical to remove all other ratemaking objectives in the exercise of judgment in developing a cost-of-service framework. The consideration of other ratemaking objectives such as fairness, stability, administrative ease, and understandability, are inherently an important element of developing a cohesive and workable COS framework. This approach is demonstrated throughout the Centra and Atrium evidence, which proports to only consider pure cost causation, but then reverts to consideration of other ratemaking objectives, as is necessary to make practical COS proposals and recommendations.

Based our evaluation of the 2019/20 GRA record as well as the record to date of this Proceeding, our expectations are as follows:

1. Conclusion #1 above should not be contentious in this proceeding;
2. Conclusion #2 above will be contentious and the key consideration for the PUB in its determination of whether to approve or deny Centra's COS proposals; and
3. Conclusion #3 above is contentious, but is not the key in deciding upon the issues in this proceeding. This issue is more a pragmatic matter in applying judgment to COS proposals.

4.0 Canadian Natural Gas Industry COS Practice Research

This section of the Evidence evaluates the completeness and implications of the research that was conducted by Atrium into the COS practices of the Canadian natural gas industry (referred to as "industry practice research") for Centra's COSMR.

The results of the evaluation can be summarized as follows:

1. The industry practice research is limited and provides no clear insights into the policy drivers and utility specific circumstances that led to the selection of the COS methodologies by the Canadian natural gas LDC's;
2. It is unclear if the industry practice research has impacted Centra's COSM review, and how, if at all, the research supports the Centra COSM proposals; and
3. There is diversity in the COS methodologies used by Canadian natural gas LDC's and specified in authoritative COS literature, with a range of acceptable methods in practice, and no singular industry best practice, to rely on.

4.1 The Industry Practice Research is Limited & Provides No Clear Insights into Policy Drivers and Utility Specific Circumstances

The terms of reference for the external consultant review of Centra's COSM set the following requirements for services and deliverables with respect to industry practice research[19]:

1. The external consultant was to conduct an analysis of industry best practices for similar natural gas distribution utilities and how this compares to the current methodology used by Centra; and
2. The external consultant was to provide an assessment of the adequacy of Centra's current COSM and of the concerns raised by participants at Centra's last GRA as it pertains to Canadian best practices and Manitoba-specific circumstances.

In response to these requirements, Atrium provided an overview of the COS methodologies used by five Canadian LDC's (Apex, Atco Gas, Enbridge, FortisBC and Liberty NB) as part of its report[20]. The discussion in the Atrium Report and Centra COS Application with respect to the industry practice research was limited to summarizing the Canadian LDC's COS methodologies at a high level.

As part of the information requests, Centra and Atrium were asked to provide their perspectives and conclusions on the industry practice research and the following observations are instructive with respect to the limitations of that research[21]:

1. When asked if the consideration of non-cost causal factors was prevalent in the COS methodologies of the Canadian LDC's, Centra indicated that it would be necessary to make

[19] Centra Exhibit 3-0, PUB MFR 1, Sections 4.1 and 5.1
[20] Atrium Report, Appendix C, summarized in Section 8.0, pages 28-29
[21] CAC/Centra 6 and CAC/Atrium 6 b

an interpretation of filings, board orders and transcripts in order to discern whether there are non-cost causal factors driving COS methodologies; and

2. As it relates to direct assignment of transmission plant to larger volume customers, Atrium conceded that the scope of its research was such that it did not include an investigation whether the utilities had any dedicated plant. Centra indicated that direct assignment would require a more nuanced understanding of each of the utility's specific circumstances.

It is acknowledged that conducting industry research is not an easy task. As is noted in the information requests, it is often necessary to undertake very detailed research through applications and filings, regulatory commission decisions and transcripts of proceedings in order to understand the history and context of how approved regulatory methodologies came about. Quite often it is necessary to further inquire with utility staff that are directly engaged in COS matters of a particular utility to gain the necessary insight on matters of policy and application of policy to specific utility circumstances.

The intent of this aspect of the evaluation of the industry practice research is not for the purposes of being critical of the work that was undertaken, but rather, to assess its value for the purposes of the PUB making determinations with respect to Centra's COS proposals.

The conclusion that flows from this aspect of the evaluation is that the industry practice research in this proceeding in terms of its depth, provided little insight into the policy drivers and utility specific circumstances that led to the selection of the various COS methodologies.

4.2 It is Unclear If or How the Industry Practice Research Impacted and Supports Centra's COSM Proposals

Matters like COSM are complex and have many nuances. Research that only relies on high-level summarization of information readily available on the public record, without a more detailed review of the underlying record or direct confirmation from the specific utilities involved, can have questionable reliability. Different COS professionals can use different terms for the same methodology or variation of a particular methodology. Often it requires a detailed review of how a COS methodology has been applied and implemented to understand where a particular variation used for a particular utility, actually falls on the spectrum of available methodologies.

With those caveats, and accepting at face value and without confirmation, the summarization of the COS methodologies of the Canadian LDC's, the key observations that flow from the industry practice research can be summarized as follows[22]:

1. Both Centra and Atrium acknowledge that there is a wide range of acceptable COS practices in Canadian LDC's which are circumstance dependant;

[22] CAC/Atrium 6 a

2. With respect to the allocation of demand-related transmission plant - of the five LDC's surveyed by Atrium, only one uses a design day coincident peak as is recommended by Atrium and proposed by Centra;
3. With respect to the allocation of demand-related distribution plant - of the five LDC's surveyed by Atrium, only one uses a design day coincident peak as is recommended by Atrium and proposed by Centra;
4. With respect to the direct assignment of transmission plant to larger volume customers – no direct assignments were identified with the possible exception of FortisBC; and
5. Atrium states it is aware of seven US states (Alaska, Illinois, Michigan, North Carolina, Pennsylvania, Washington, and West Virginia) that use a peak and average methodology or one similar to the average and excess method for the allocation of demand-related costs[23].

Based on a review of the terms of reference of the external COSM review that was issued by Centra, it could be expected that the research conducted would be reasonably robust and used to support the COS conclusions and recommendations made by Atrium and Centra.

The Centra COSM Application and the Atrium Report do not specifically address how, if at all, this industry practice research impacted the review of Centra's COSM. For example, did this research produce additional options that were evaluated in terms of advantages and disadvantages? Did the research eliminate any options that Centra was considering? If so, why aren't these types of considerations documented in the COSM filing?

It is also not clear if the industry practice research supports or refutes the COS proposals of Centra. The industry practice research appears to be simply part of the COSM filing without any assessment of its impact on, or concurrence with, the ultimate Centra COSM proposals.

4.3 There is Diversity in COS Practice with a Range of Acceptable Methods and No Singular Industry Best Practice to Rely On for COS Decisions

In addition to reviewing COS methodologies that are used in practice, it is also useful to consider the COS methodologies that are supported by the authoritative literature for COS practitioners.

A review of authoritative COS literature would also support the conclusion that there is diversity in COS practice and a range of acceptable COS methodologies. Evidence of this conclusion is as follows:

- As Atrium acknowledges, The National Association of Regulatory Utility Commissioners (NARUC) provide three foundational methodologies to allocation demand-related costs 1) CP method 2) Non-Coincident Peak method and 3) Average and Excess Demand (of which PAVG is variation)[24].

[23] PUB/Atrium 1a
[24] Atrium Report, page 7

- The American Gas Association also identifies the three same methods in addition to providing a discussion on the Atlantic Seaboard Formula and the United Formula. The Atlantic Seaboard Formula allocates 50% of fixed costs on the basis of demand and 50% on the basis of energy. The United Formula allocates 75% of costs on the basis of energy, with the remaining 25% on the basis of Demand[25].
- More recently, in January 2020, the Regulatory Assistance Project (RAP) released an "Electric Cost Allocation for a New Era" Manual. This manual provides a robust and deep review of cost allocation methodology that includes a number of methodologies in addition to the foundational three.

Further, as the PUB concluded in Order 164/16, while the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment and there is no single industry standard that applies to all COSS decisions.[26]

From the limited industry practice research and the acknowledgements of Centra and Atrium, the authoritative literature on acceptable COS methodologies and prior PUB decisions, it is clear that there is both diversity in practice and a range of acceptable COS methodologies in Canada. It also follows that there is no singular industry best practice that the PUB can rely to resolve the in-scope issues that are before for it in this proceeding and make COS decisions.

[25] Gas Rate Fundamentals, Fourth Addition, American Gas Association, pages 97-98 and 141-145
[26] Order 164/16, page 5

5.0 The Allocation of Demand-Related Costs

This section of the evidence evaluates the Centra COS proposals to replace the Peak and Average allocator which is currently used for the allocation of demand related costs with (1) a Coincident Peak Day allocator for transmission & distribution plant and year-round pipeline capacity and (2) a Winter Season Demand in excess of Summer season Demand allocator for storage and related pipeline capacity.

The results of the evaluation and recommendations in this section of the Evidence, can be summarized as follows:

1. There are three generally accepted methods for the allocation of demand costs including coincident peak (CP), average and excess (peak and average or PAVG) and non-coincident peak (NCP);
2. Centra's rationale for its proposed CP allocator for demand-related transmission and distribution costs is that it more accurately reflects pure cost causation;
3. Centra's rationale for proposing CP to allocate year-round pipeline costs and the Winter in Excess of Summer Demand for storage & related pipeline costs are unclear and the rationale for conceptually different methodologies for these two components of upstream costs is also unclear;
4. It is recommended that the PUB retain the peak and average allocator for the Allocation of the demand-related transmission and distribution Investment and the allocation of demand-related upstream year-round pipeline and storage & related pipeline costs – as it better aligns with the broader PUB definition of cost causation and is directionally consistent with how Centra's downstream system is both planned and operated and with Centra's gas supply operations; and
5. The issues associated with the Interruptible Class are minimized by retaining the peak and average methodology for the allocation of demand-related upstream and downstream costs.

5.1 There are Three Generally Accepted Methods for the Allocation of Demand Costs including Coincident Peak, Average & Excess and Non-Coincident Peak

There are a range of acceptable methods for the allocation of transmission and distribution demand-related costs including coincident peak (CP), average and excess (peak and average or PAVG) and non-coincident peak (NCP).

A brief description of each methodology is as follows:

- A CP method is intended to allocate costs classified as demand on the basis of each class's volumes consumed at the time of the highest measured load of all customer classes on the system. The rationale for this approach is that the system is designed to handle extreme weather conditions. Hence, from a strict engineering perspective, the costs incurred in ensuring the system has sufficient capacity under extreme weather conditions are based on the forecast demand under those conditions.

- An NCP is determined based on the maximum demand of each customer class regardless of when the system peak occurs. In this case, it is likely that maximum demands occur at different times. Some utilities, like Enbridge Gas, who use this method, do so to account for the fact that some of its customers do not peak at the time of the system peak and would otherwise avoid demand-related cost responsibility. The use of NCP as an allocator is more prevalent for the allocation of demand-related distribution costs, than for transmission, on the basis that there is homogeneity of end-users such that NCP is a larger factor in the planning and operations of regulation stations and distribution pipeline.

  It is also used for the allocation of demand-related transmission investment, as noted for Enbridge Gas above. However, depending on how transmission is defined and functionalized, transmission is often viewed as more greatly benefiting from the diversity of customers (and thus less homogeneity) and thus a greater factor in the planning and operations of transmission investment.

  There has been little evidence and data advanced in this proceeding to be able to evaluate the merits of the use of NCP which was summarily dismissed by Atrium.[27]

- The average and excess (or used and unused) methodology, of which PAVG is a more simplified version, recognizes not only the class loads at the time of the system maximum peak, but also the amount of annual energy usage of all classes. The split between peak and average may be based on system load factor, as Centra does, or may be based on more arbitrary splits such as 50/50 between demand and energy.

Within each of these broad methodologies, there are also numerous variations in terms of how a particular methodology is applied. It is critically important to understand the application in order to understand the intent of the methodology. That is, there is also a range of treatments within each methodology.

For example, the concept of a CP allocation is premised on the notion that investment in capacity is determined by the peak load of the gas utility. The peak demand allocation might focus on a single peak, such as the utility's design day which is based on the extreme weather temperature conditions under which the utility's gas system is designed. Other variations might include the average of several cold days, an average of winter and summer peaks (2CP), 4CP, to an average of 12 CPs. Importantly, from a cost-of-service perspective, the greater the number of peak periods reflected result in a methodology has the implicit effect of allocating demand costs on the basis of energy. Conversely, a CP methodology that assigns transmission and distribution investments on the basis of the single extreme weather conditions costs has the effect of ascribing a cost allocation methodology on the basis of 100% weighting to this single event, even though such an event is rarely experienced on a gas system.

[27] Atrium Report, page 8

In some instances, it may be appropriate to determine the peak demand responsibility on an hourly basis rather than a daily basis where hourly requirements drive a gas utility's investment in transmission and distribution facilities based on its system design criteria. For those utilities who elect a CP allocation methodology, a forecast of system demand based on the class load profiles under normal weather conditions and not on design (most extreme) weather is sometimes used; hence the peak demands can be characterized as typical rather than extreme. The concept underlying this approach is that it is viewed to be less rigid to allocate capacity costs based on typical usage of the system, rather than design considerations.

5.2 Centra's Rationale for its Proposed CP Allocator for Demand-Related Transmission and Distribution Costs is that it More Accurately Reflects Pure Cost Causation

As part of this Application, Centra proposes "transitioning to a more pure cost-causation approach afforded by the use of a Coincident Peak allocator for the allocation of transmission and distribution demand related costs as recommended by Atrium"[28]. The proposed change is a move from the current use of a peak and average methodology.

Our understanding of Centra's rationale for its proposal is as follows:

1) While the use of a CP allocator would a be departure form Centra's long standing PUB approved methodology, it more accurately reflects the cost causation principle"[29]; and
2) Its system has evolved overtime such that the Interruptible Class is now firm for downstream purposes, and thus there are allocation methods other than PAVG that can be used while still ensuring cost recovery from all users of the system[30].
3) Its proposals also take into consideration more recent guidance from the PUB expressed in Order 164/16 regarding the importance of cost causation and desire to keep non-cost causal considerations out of the cost allocation phase"[31].

Further, while Atrium recommended a design day metric to calculate a CP allocator, it is unclear from the record if Centra is proposing to develop a design day metric or to continue to rely on a CP metric similar to the existing peak day calculation[32] as reflected in the current PAVG methodology.

Interestingly, Atrium recommends the use of a maximum design day in order to apply the CP allocation despite the fact that it not only is unavailable, but is also not used by Centra for its gas planning purposes. It is difficult to rationalize the theoretical superiority of a maximum design CP as cited by both Atrium and Centra, when it is clear that it is not even the basis by which Centra's gas planning designs its system.

[28] Centra Application, page 30
[29] Centra Application, page 29
[30] Centra Application, page 30
[31] CAC/Centra 1a
[32] PUB/Centra 8b and PUB/Centra 9a

Further, 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". Utilities which use a forecast of system demand based on the class load profiles under normal weather conditions and not on design (most extreme) weather, view this approach as less extreme for cost allocation since it reflects actual typical usage rather than extreme demands rarely experienced.

5.3 PAVG Aligns with the Broader PUB Definition of Cost Causation and is Directionally Consistent with how Centra's System is both Planned and Operated

Centra's current methodology allocates demand-related transmission and distribution costs based on PAVG. The peak component and the average component are split based on system load factor (LF) characteristics. Load factor, which is defined as the average use as a function of use on the peak day, is a reasonable approach to represent how the gas system is used throughout the year. The portion of utility facilities and related expenses required to serve the average load is allocated on the basis of each class's average demand (that is, annual volumes averaged over either 365 days or 8760 hours). Average use, as a proportion of peak load, is by definition load factor and hence, average demand (average volumes) are weighted by system load factor. The remaining demand related costs are allocated to each class based on excess or unused demand (i.e. 1-LF). As is the case with the Average and Excess method, PAVG has the effect of allocating a portion of the utility's demand-related costs on a commodity-related (throughput) basis.

For Centra, the result is as follows:

- Approximately [redacted] of demand-related costs are weighted and allocated based on CP; and 1e
- The remaining approximate [redacted] are weighted to energy and allocated based on a class's average annual volume.

Centra states that the current peak and average methodology, which Centra has employed at least since the late 1980's, was adopted for the following reasons:

- It recognizes the utilization of the system as an explicit factor to be included in determining cost responsibility;
- It is relatively simple and straightforward;
- It is a widely accepted method of cost allocation; and
- Is considered cost-causal in many state and province jurisdictions.[34]

Our observations regarding the allocation of the demand-related component of transmission and distribution investment are as follows:

[33] PUB/Centra 8b and PUB/Centra 9a
[34] CAC/Centra 10a

1. There is no question that the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question - which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a utility's customers and the costs incurred by the utility in serving those customers.

   The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on one hand and the costs incurred by the Company in serving those requirements on the other hand. It is also important that no service should be provided at no cost to customers and, thus, caution must be exercised regarding the potential for free riders in adopting a particular methodology – those who do not use service on-peak or who are able to shift demand and modify behaviour in order to reduce and/or avoid cost responsibility;

2. It is understood that gas utilities design and install its system capable of meeting its customers' design day requirements at the time of initial installation. Placing these facilities in service permits the utility to serve the changes in load due to extreme weather (i.e. the design hour load). Once facilities are put in place to serve customers, the costs associated with these facilities are by their nature fixed and do not vary;

   While the costs of transmission and distribution are largely fixed from an accounting perspective, in evaluating the relative merits of an acceptable demand-related allocation methodology, for purposes of cost of service it is important to not only consider how Centra's system is built from a strict engineering perspective, but also how Centra's system is used by customers and thus operated throughout the year. This perspective is important as it provides insight into the factors and benefits to customers the system provides;

3. Centra serves nearly 300,000 customers, of which over [redacted] of customers served are SGS customers (which includes residential), over [redacted] of total annual volumes serve the SGS 1e load, and nearly 60% of Centra's total revenue is contributed by SGS customers. Centra serves a fairly low load factor system that requires more peaking plant and less base load plant;

4. The use of the PAVG methodology as currently employed by Centra recognizes the prevalence of peaking plant put in place to serve the load requirements of its customers. By weighting the peak component of PAVG by 1-LF, or approximately [redacted] correlates and is consistent with the peaking investment put in place to serve customers. Similarly, by 1e weighting the average component of PAVG by LF, or approximately [redacted] corresponds with the relatively less amount of baseload investment made by Centra in order to serve customer base load requirements over the course of the year. Baseload plant allows for continuous year-round use, in addition to allowing for some capacity during the year;

5. The results of the PAVG methodology is that from a cost-of-service perspective, customers pay for Centra's demand-related transmission and distribution investment weighted by the primary consideration for which the assets are put in place, that is, to serve peak requirements, but there is also weight to reflect the secondary benefits the investment provides and for which customers use throughout the year. Incorporating each class's portion of system average demand is an implicit acknowledgement that average load drives a portion of the demand-related costs owed to base-load resources, in addition to costs incurred to serve peaking requirements;

6. Centra's uses a detailed gas design system operations model, the DNV GL's Synergi[35](Customer Management Model) to estimate load for purposes of designing its system to ensure it can meet customer requirements under all conditions. Centra determines the load on its transmission and distribution pipeline on the basis of several factors including pressure, customer usage (volumes) related to non-heat dependant baseload, as well as temperature dependant load as inputs. PAVG was implemented and in place for decades in part, as it replicates, based on simplified characterizations of Centra's system operations, Centra's load estimation process;

7. Centra takes advantage of its excess capacity availability in the summer provided by low load factor customers, by utilizing available capacity for purposes of storage in order to optimize its total cost to serve for all customers; and

8. Allocating transmission and distribution demand-related costs based on the extreme year conditions CP allocator as proposed by Centra gives no weight to either peak use in normal conditions which underpins annual revenue requirement or the energy benefit provided to customers during the year (that is, baseload service).

5.4 It is Recommended the PUB Retain PAVG for the Allocation of the Demand-Related Transmission and Distribution Investment

It is understood that if a gas utility's system was sized and installed to accommodate average gas demands, it would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From gas engineering perspective, its appropriate and clear that a peak demand design criterion is utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system. However, cost allocation does and should weight costs, primary benefits and secondary benefits also.

It is recommended that the PUB retain the use of the PAVG methodology for the allocation of downstream transmission and distribution demand-related costs for the following reasons:

[35] 2019/20 Centra GRA, IGU/Centra 16

1e

1. The PAVG methodology that weights demand-related costs by [redacted] and provides a [redacted] weighting of annual throughput is well aligned with the broader definition of cost causation as per the PUB's prescribed COS policy that considers how the system is used throughout the year (s); how Centra's is system is built; as well as primary and secondary benefits;
2. PAVG is directionally consistent with how Centra's gas planners determine its load requirements;
3. PAVG recognizes the benefits of the excess summer capacity made available by low load factor customers in order to optimize the total cost to serve all customers;
4. Centra's proposed CP methodology that provides for 100% weighting based on a purported theoretical ideal of extreme max weather conditions results in a rigid and very narrow view of cost causation, contrary to the PUB's COS policy determinations; and
5. As Centra states, the PAVG methodology is reasonably cost-causal, simple and straightforward and well recognized in industry.

5.5 Centra's Rationale for Proposing CP to Allocate Year-Round Pipeline Costs and the Winter in Excess of Summer Demand for Storage & Related Pipeline Costs are Unclear and the Rationale for Conceptually Different Methodologies is Also Unclear.

There are a range of acceptable methods for the allocation of the demand-related costs associated with Year-Round (TCPL) Pipeline and Storage & Related Pipeline. The broad allocation methodologies include coincident peak (CP), average and excess (peak and average) and non-coincident peak (NCP). The Seasonal Resource Stacked-Based Analysis as well as the Winter in Excess of Summer Demand alternatives are simply detailed variations of these broad methods. A brief description of these methodologies was provided in Section 5.1.

It appears that Centra is recommending replacing the PAVG methodology for upstream demand-related costs as follows[36]:

1. Replace the PAVG allocator for upstream capacity costs with a CP allocation for Year-Round Pipeline (TCPL) capacity;
2. Replace the PAVG allocator for Storage and Related Pipeline capacity with the Winter Season Demand in Excess of Summer Season Demand allocator; and
3. Centra proposes that Interruptibles would be excluded from the CP allocation for year-round pipeline capacity but included in the allocation of storage and related pipeline capacity.

Centra currently allocates all upstream demand-related costs based on the PAVG methodology (for both Year-Round Capacity and Storage & Related Pipeline Capacity). The allocation methodology for upstream capacity has been consistent with the allocation methodology related to Centra's own downstream transmission and distribution pipeline for decades.

The rationale for Centra's fundamental philosophical change in methodology from PAVG to CP for Year-Round Pipeline costs and the change from PAVG to a Winter in Excess of Summer Demand is not readily apparent in Centra's Application. Centra simply states that Atrium's

[36] PUB/Centra 18f-g

recommendation for the changes are "worthy of additional consideration"[37]. It is also unclear why Centra would propose methodologies that conceptually differ between Year-Round Pipeline Capacity and Storage & Related Pipeline Capacity.

5.6 PAVG Aligns with the PUB's Broader Definition of Cost-Causation and is Consistent with Centra's Gas Supply Operations

Centra's current methodology allocates upstream demand-related costs based on PAVG. Similar to downstream Transmission and Distribution pipeline investment, the result is that approximately [redacted] of upstream demand-related costs are weighted and allocated based on CP. The remaining 1e
approximate [redacted] are weighted to energy and allocated based on a class's average annual volume.

Our observations regarding the allocation of the demand-related component of Year-Round Pipeline Capacity and Storage & Related Pipeline Capacity investment are as follows:

1. In evaluating the appropriate allocation methodology for upstream year-round capacity costs, the analysis and conclusions drawn in Sections 5.3 & 5.4 above are equally applicable. The PUB policy has been and is to apply a broader definition of cost causation and not apply a 100% weighting to peak metrics, but rather to consider a weighting of both design parameters and volume as reflected in the PAVG methodology.

2. Centra's describes its proposed Winter in Excess of Summer Demand allocation for storage and related pipeline capacity costs as a relative comparison of winter class contribution to the total winter excess demand where winter excess is calculated as the average winter load less the average summer load. Centra states that this equates to the average monthly throughput for November through March (winter) minus the average throughput for April through October (summer)[38].

   It is important to note that the difference between average monthly throughput in winter and summer equates to a volume allocator with an implicit demand influence. Thus, this methodology places a greater weighting of annual volumes to allocate storage and related pipeline capacity costs than the current PAVG methodology and appears to conflict with Centra's purely cost-causal policy objective.

3. No rationale has been provided to justify why a CP methodology is appropriate for purposes of allocating Year-Round Pipeline (TCPL) demand-related costs, and yet, a fundamentally different methodology that is heavily volumetric driven with some demand influence, that is the Winter in Excess of Summer Demand, is viewed as more cost causal for purposes of allocating Storage & Related Pipeline investment.

[37] Centra Application, page 35, lines 1-2

[38] PUB/Centra 8d

5.7 It is Recommended the PUB Retain the PAVG for the Allocation of the Demand-Related Upstream Year-Round Pipeline and Storage & Related Pipeline Cost

The PUB's policy reflects a broader definition of cost causation that not only looks at design parameters but also gives consideration to use, and primary and secondary benefits also. Centra's proposed CP methodology for Year-Round Pipeline capacity provides for 100% weighting based on a purported theoretical ideal of extreme conditions, the basis of such a determination has not been provided in the Application, and results in a rigid and very narrow view of cost causation, contrary to the PUB's COS policy. Centra's proposal to move to an allocator that is essentially volumetric with some implicit demand recognition may comport with the PUB's broader definition of cost causation, but is unclear, and may place too heavy a weighting on volumes for costs incurred largely to serve customer demand.

Our recommendations are as follows:

1. It is recommended the PUB retain the PAVG methodology for both Year-Round Pipeline and Storage & Related Pipeline demand-related costs. PAVG weights demand-related costs by [redacted] based on peak, and provides a [redacted] weighting of annual throughput is well 1e aligned with the broader definition of cost causation as per the PUB's prescribed COS policy that considers how the upstream system is planned for and used throughout the year; and
2. The retainment of the PAVG methodology also avoids the complications associated with Interruptible customer which is further discussed in Section 5.8 below.

5.8 The Issues Associated with the Interruptible Class are Minimized by Retaining the PAVG Methodology for the Allocation of Demand-Related Upstream and Downstream Costs

Centra is proposing, from a downstream perspective, to incorporate the Interruptible Class as part of the maximum design CP and allocate a full proportion of the demand-related transmission and distribution investment, compared to the current treatment that assigns a partial responsibility of these costs. From an upstream perspective, Centra proposes to eliminate the Interruptible Class from an allocation of Year-Round Pipeline (TCPL), but include the Interruptible Class in the allocation of Storage & Related Pipeline costs.

Centra's current methodology assigns cost responsibility to the Interruptible Class related to downstream Transmission and Distribution, as well as Year-Round Pipeline (TCPL) and Storage & Related Pipeline costs based on PAVG. The Interruptible Class is currently excluded in the allocation of "peak" component of the PAVG methodology on the basis that these customers are not provided service at the peak.

Centra's rationale for the change in the allocation of costs to the Interruptible Class is as follows:

1. Centra has firmed up all Interruptible customers from a downstream perspective, despite that the fact that Interruptible customers have been receiving the benefit of a discounted rate. That is, from a planning perspective, downstream, Centra is able to meet all customer load requirements on a firm basis;
2. From an upstream Year-Round Pipeline (TCPL) perspective, Centra states that its contracted upstream peak capacity does not include the peak requirements of the Interruptible Class[39] and as such should be excluded from the cost responsibility associated with Year-Round (TCPL) pipeline costs; and
3. Given the needs of the Interruptible Class are served using gas from storage, Centra proposes to include this class in the allocation of Storage & Related Pipeline capacity costs[40].

Our observations and recommendations are as follows:

1. From an economic perspective, Centra has either explicitly or implicitly concluded that the cost incurred to provide firm service to Interruptible customers is less than the discount provided through current rates. Unfortunately, there has been no analysis provided to either demonstrate this or the additional cost incurred in providing firm service to Interruptible customers;
2. Based on Centra's CP proposal for Year-Round (TCPL) Pipeline capacity, it should be noted that the Interruptible Class will avoid all demand-related TCPL costs despite using and benefiting from the capacity paid for by firm customers for a significant portion of the year, each and every year. The total upstream capacity costs of Centra are nearly $60.0 million[41] annually which Interruptible customers will avoid with a move to Centra's proposed allocation methodology;
3. Centra's proposal to include in the allocation of Storage & Related Pipeline costs on the basis of the Winter in Excess of Summer Demand appears to be a compromise position to avoid a situation whereby the Interruptible customers are excluded from all upstream demand-related costs. This is because the procurement of upstream Storage & Related Pipeline costs are largely incurred on the basis of the capacity requirement to serve Centra's customers regardless of the fact that Interruptibles "make use" of these services for large portion of the year. "Making use" of these services results in a decision that conflicts with Centra's stated policy objective to move to "pure cost causation";
4. In terms of Centra's proposed Winter in Excess of Summer Demand methodology, Centra states that Interruptible customers "make use" of Storage & Related Pipeline investment. There has been no evidence adduced that demonstrates the Winter in Excess of Summer Demand is so significantly superior in terms of cost causation for the Interruptible customers compared to the PAVG;
5. Centra states that a rationale for moving to a pure cost-causal CP methodology is based on the fact that Interruptible customers make use of Centra's downstream system in times

[39] Centra Application, page 35
[40] Centra Application, page 35
[41] Centra Application, Schedule 10.1.2

of upstream curtailment. This is simply non-sensical given that the Alternate rate reflects a downstream capacity cost component to recognize downstream capacity usage during upstream curtailment periods. And in any event, Centra states that it now provides firm downstream service to Interruptible customers and, as such, Interruptible customers will be responsible for a full share of demand-related transmission and distribution investment; and

6. It is recommended the PUB retain the PAVG methodology for the reasons noted in Section 5.7 and thus will avoid the complications associated with the Interruptible Class that are inherent in Centra's COS proposals.

6.0 Classification of Distribution Plant

This section of the evidence evaluates the classification of distribution plant between customer and demand, the methods available to determine the split between the customer and demand component of distribution plant and addresses the updating of diameter length and service & meter studies by Centra for the next GRA.

The results of the evaluation and recommendations in this section of the Evidence, can be summarized as follows:

1. It is recommended that the PUB retain the current classification of distribution plant between demand and customer as the split between demand and customer aligns with the broader definition of cost causation in accordance with the PUB's COS policy;
2. It is recommended that the PUB retain the diameter-length distribution classification study as a means to estimate the weighting of customer and demand for distribution plant as this methodology is the most commonly used; and
3. It is recommended that Centra update the diameter-length and service & meter Studies for its next GRA to ensure that they are providing a reasonable basis for the allocation of distribution plant.

6.1 It is Recommended the PUB Retains Current Classification of Distribution Plant Between Demand and Customer

As it relates to the classification of distribution plant, it is commonly viewed that there are two cost factors that influence the level of cost associated with distribution facilities installed in expanding a gas distribution system, including total installed footage of distribution mains (the number of customers) which is intended to consider customer dispersion and geography, and the size of the distribution main (i.e. the diameter of the main) which considers customer's capacity requirements. Centra's current classification attributes 67% weighting to demand and a 33% weighting based on customer numbers. Implicit in the Application, Centra is proposing to continue to classify Distribution investment based on demand and customer numbers.

Another alternate view is that the investment in distribution is a function of only the diameter of the main, that is, distribution investment is driven only by the diameter of the main to serve the peak requirements of a utility's customers. As is the case for MH electric COS, distribution assets (not including service lines, transformers and meters) are classified 100% demand driven by the cost incurred in serving customer class's peak demand requirements (NCP) on the basis that these costs are driven by a mix of peak loadings in different seasons, months, days and hours, and because the correlation between customer dispersion and customer numbers is tenuous.

Our observations and recommendations are as follows:

1. Based on a review of the gas industry research provided, the predominant view appears to be that distribution plant investment is driven by both demand considerations and customer numbers;

2. Based on the record of this proceeding, there is little evidence that would allow for any other recommendation; and
3. The split between demand and customer aligns with the broader definition of cost causation as per the PUB's COS policy.

6.2 It is Recommended the PUB Retains the Current Diameter-Length Distribution Classification Study

The two most common methods for the classification of distribution plant including the Zero Intercept Study and the Minimum System Study. Centra's current COS methodology for classification of distribution plant is based on a diameter-length study, which is a variation closely related to the minimum system study referred to in Centra's Application. A brief description of this method is as follows:

- The diameter-length study estimates the total capacity of the distribution mains by multiplying the length of pipe by its diameter. The minimum capacity of the system (customer component) is then determined by multiplying the same length of distribution main by the minimum-sized pipe (Centra assumes ¾ inch);
- In theory, a minimum sized pipe is put in place to only connect customers and provides for no capacity service. The ratio of the minimum capacity to the total capacity is the customer-related percentage of distribution mains investment; and
- Using this methodology, the linkage between the diameter of the pipe and its capacity captures the most basic aspects of this relationship.

A zero-intercept method may be preferred as even a ¾ inch distribution main is viewed to provide some capacity. Atrium states that the Minimum System method is the most utilized by natural gas utilities in North America and is best suited for Centra's circumstances.[42]

It is recommended Centra continue with a diameter length study for the classification of distribution investment between demand and customer numbers. This classification is common practice, and the minimum system approach is generally favoured.

6.3 It is Recommended the Diameter-Length and Service & Meter Studies Be Updated for Centra's Next GRA

Centra originally proposed to refresh the development of the customer component of distribution investment using either a Zero Intercept or a Minimum System method[43]. Centra last updated its diameter length study prior to the 1996 COS methodology review. However, in response to information requests, Centra clarified that its records are insufficient to undertake a Zero Intercept

[42] PUB/Atrium 5
[43] Centra Application, page 2

study and that while it may be possible to complete a Minimum System study, numerous estimates and assumptions would be required.[44]

Atrium also recommends that Centra update its Service & Meter investment studies. Centra's Service & Meter Investment studies were last reviewed and updated in 2004. Atrium further recommends that once these studies are updated, that Centra then index the vintage year installation to current year costs[45]. In the Application, Centra indicated that it supports the updating of these studies and plans to do so for the next GRA and agrees that indexing is a worthwhile refinement[46].

However, in response to information requests, Centra now indicates that it now proposes to index the results of the studies[47]. It is unclear if Centra is proposing to update the studies or if it simply proposing to index the outdated studies from 2004.

Our observations and recommendations are as follows:

1. Our understanding is consistent with Centra in that its records were insufficient to undertake a Zero Intercept Study. Centra states that its records continue to be insufficient to undertake this type of study and is thus not unexpected;
2. Centra last prepared a diameter length study approaching 30 years ago, and the Service & Meter studies nearly 20 years ago. It is recommended these studies be updated by Centra for the next GRA. It is observed that Centra has recently updated its Depreciation Study which is conducted approximately every five years. As such, it is timely to update the diameter length and meter & service studies. If these studies are not updated now, it begs the question of when such studies will be reviewed, if ever;
3. It is interesting to note that while Centra is proposing a move to a pure cost causal and transparent COS methodology, for reasons of administrative simplicity, it is not prepared to update the studies; and
4. It is observed that any financial, cost allocation or rate study involves simplifying assumptions and often has limitations in terms of data availability. Simplifying assumptions and data limitations are not valid reasons for failure to maintain current studies.

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[44] PUB/Centra 18 c-e
[45] Atrium Report, page 21
[46] Centra Application, page 35
[47] PUB/Centra 18 f-g

7.0 Allocation of Demand-Side Management (DSM) Costs

This section of the evidence evaluates the allocation of gas operations DSM costs, including the consistency with the allocation treatment with electric DSM costs.

The results of the evaluation and recommendations in this section of the Evidence, can be summarized as follows:

1. Gas operations DSM is currently directly assigned based on class participation, while electric operations DSM is treated as a system resource and follows the allocation of generation;
2. Centra appears to prefer retaining its current direct assignment approach for Gas DSM investment based on its view that there are only minimal incremental economic benefits to the overall natural gas system;
3. It is recommended that gas DSM be treated conceptually consistent with electric DSM, functionalized as transmission and allocated based on the peak and average allocator given that this investment benefits not only the participating classes, but also provides broader system and societal benefits and is consistent with the PUB's COS policy of a broader definition of cost causation.

7.1 Gas DSM is Currently Directly Assigned based on Class Participation while Electric DSM is treated as a System Resource and Follows the Allocation of Generation

The COS treatment of DSM investment differs between gas and electric operations.

Centra currently allocates the annualized forecasted cost of DSM based on anticipated participation in DSM activities. Centra states that Efficiency Manitoba (EM) provides the "DSM costs grouped into the specific customers classes used by Centra"[48]. Centra goes on to state that it is unaware of how EM reconciles its customer groupings with Centra's rate classes[49]. For purposes of rate design, it classifies these costs as energy[50]

An alternative allocation methodology raised in this proceeding (the concept of which is used in electric COS) considers that gas DSM costs not only serves to reduce natural gas purchases (i.e. commodity costs), but also contributes to a reduction in the costs of transportation, storage, transmission, and distribution investments costs, and provides environmental benefits by lowering greenhouse gas emissions.

[48] PUB/Centra 3e
[49]PUB/Centra 3e
[50] Centra Application, page 18, lines 25-26

Under this alternative, the costs of gas DSM could be allocated as a system benefit. Centra states that if such a perspective is taken, the appropriate allocation would be to functionalize the costs as production and allocate the costs based on forecasted annual energy by class[51].

7.2 Centra Appears to Prefer Retaining its Current Direct Assignment Approach for Gas DSM Investment

While Centra has not taken a firm perspective on the allocation of gas DSM costs, it appears that Centra's preference is to continue with its current approach of allocating gas DSM costs based on class participation[52] based on the following:

1. Centra asserts that gas DSM primarily provides economic benefits to the participating customers and only minimal incremental economic benefits to the overall system; and
2. Centra asserts that a methodology consistent with electric operations may not be cost causal given that gas DSM is less cost effective as gas operations are unable to benefit by the deferral of more costly generation investment or increases in export revenues (by freeing up energy to be sold extra-provincially that would otherwise be consumed by domestic customers).

7.3 It is Recommended Gas DSM is treated Conceptually Consistent with Electric DSM, Functionalized as Transmission and allocated based on PAVG

Centra's current allocation of DSM costs assumes that only those who participate benefit, and thus it is reasonable that those who participate should pay for those costs, based on the principle of cost causation.

However, in our view, Centra's perspective of the purpose and benefits of gas DSM is too narrow as the investment in DSM is not driven by the existence of the participating customers but provides benefits that extend beyond the participant as follows:

1. Reduce participants usage, and thus, serves to reduce the participants commodity bills;
2. Lower participant usage will serve to not only lower commodity requirements, but will also serve to reduce consumption at peak periods resulting in lower requirements in upstream and downstream capacity investment thereby lowering the total revenue requirement; and
3. Results in socio-economic and societal benefits, such as the lowering of greenhouse gas emissions.

While the economic case and the deferral of plant is readily understood and quantified for electric operations, it is expected that at least some of those benefits, such as reduced transmission, distribution and upstream capacity must also exist for gas DSM. Gas customers have exhibited a declining use per customer due to the improved efficiency of homes and businesses which

[51] PUB/Centra 3c
[52] PUB/Centra 3; CAC/Centra 7 a-b

lowers the design day requirements compared to the design day requirements at the time when the original plant was designed and installed to serve customer loads and thus, serves to lower overall revenue requirement for all customers. As such, the costs of gas DSM are driven to reduce usage which results in the reduction of system costs, and also provides socio economic and environmental benefits such as the reduction of greenhouse gases.

The PUB COS policy is that cost causation requires consideration of all of the uses of an investment to recognize that the primary and secondary benefits influence the planning and justification of assets. When gas DSM is analyzed within this policy framework, it is reasonable to consider that it benefits not only the participating classes, but also broader societal imperatives[53]. Additionally, this broader view of cost causation aligns with Centra's corporate decarbonization direction and allows for alignment in the treatment of DSM cost allocation between electric and gas operations. The Efficiency Manitoba Act was established in January 2018, which further underscores the broader primary and secondary benefits of gas DSM[54].

For these reasons, it is recommended that gas DSM investment be viewed as a system resource, functionalized as transmission and allocated based on PAVG which allocates these costs on both a demand and volumetric basis. This treatment recognizes that benefits are obtained by both non-participants as well as participants through the lowering of commodity costs and capacity investment in the long term. It also allocates DSM costs to all Centra customers and thus, recognizes the overall societal benefits provided. To functionalize DSM on the basis of production and allocated on the basis of energy, as Centra suggests, results in T-service and Direct Purchase customers avoiding cost responsibility for an investment that provides broad societal benefits and which conflicts with the spirit of DSM investment.

[53] PUB/Centra 3d
[54] CAC/Centra 7a

8.0 Direct Assignment of Transmission Plant to the Special Contract (SC) & Power Station (PS) Classes

This section of the Evidence evaluates the Centra COS proposal to directly assign transmission plant to the Special Contract and Power Station customer classes.

The results of the evaluation and recommendations in this section of the Evidence, can be summarized as follows:

1. Utility plant is fungible in that the investment can serve different purposes over time and as such is generally allocated rather than directly assigned to customers classes;
2. Centra's proposal to direct assign transmission plant to the Special Contract and Power Station customer classes is based on the recent evolution of its system configuration;
3. It is recommended that the Special Contract and Power Station customer classes continue to receive a broader allocation of transmission plant (and not a direct assignment) as the Brandon/Southwest Area System continues to be integrated under a broader view of cost causation consistent with the PUB's COS policy;
4. It is recommended that no interim rate reduction be provided to the Special Contract customer class as a result of this proceeding, as Centra's customer impact analysis that is relied upon to propose this reduction is incomplete and outdated and such a measure would constitute retroactive ratemaking; and
5. If the PUB approves any changes flowing from this proceeding, it is recommended that Centra be directed to file two COS studies at the next GRA, one that reflects all the COS changes as well as the updated revenue requirements, and one that excludes the COS changes such that the impacts as a result of the COS changes can be isolated and tested.

8.1 Utility Plant is Fungible as it Can Serve Different Purpose Over Time and Generally Allocated Rather Than Directly Assigned to Customers Classes

All classes are allocated the costs of Centra's broad transmission infrastructure costs as transmission has been viewed as integrated and commingled and all customers benefit from the integrated nature of Centra's system.

The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignment is used in cost allocation when costs are readily identifiable as belonging to a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers.

However, it is unrealistic to generally expect that plant and expenses of a utility can be directly assigned because the nature of utility operations is characterized by the existence of common use facilities as customers are served through integrated facilities.

Typically, direct cost assignments are based upon the equipment located on the customer's property or facility. Facilities that run along the public right of way, for example, are generally not directly assignable as these are typically fungible assets of the utility. Fungible in this context means that assets serve different purposes over time - a line that may serve one customer today, served many customers previously and can at other times can very easily attach another customer. Further, these assets may serve a customer under some conditions, such a normal operating conditions, but may not be able to support the customer (s) under all operating conditions.

As a result, to the extent a utility's plant and expenses cannot be directly assigned to customer groups, allocation methods must be derived to assign or allocate the costs to the various customer classes.

In the specific circumstances of Centra, there is a direct assignment of metering and regulation costs for the SC and PS classes, as well as for all customer classes as those costs are onsite the customer premises and it is readily apparent that these costs directly serve only the customer who uses them and cannot be used to serve other customers. In this case, the cost allocation treatment, that is, direct assignment is clear.

8.2 Centra's Proposal to Direct Assign Transmission to the SC and PS Classes is Based on the Recent Evolution of its System Configurations

Centra is proposing to direct assign transmission plant to the Special Contract and Power Station Classes. Centra asserts that given the evolution of its system configuration it is now able to identify facilities used to serve the Special Contract and Power Station classes exclusively in normal operating conditions which do not serve load for any other customers. Centra states:

> "Additionally, the pipelines that serve this customer class **predominantly** have a one-way relationship with the rest of the system. That is to say that the remainder of the transmission system can receive pressure and capacity support from the pipelines that serve the Special Contract Class, but the rest of the Brandon system, with the exception of the facilities serving the Brandon Power Station, cannot **generally** be used to serve the load requirements of the Special Contract Class.
>
> Similarly, the facilities that serve the Power Station in Brandon do not serve any other customers **under normal operating conditions**."[55] (Emphasis added)

Based on a review of the responses to information requests, however, it is unclear whether Centra is requesting only a direct assignment of transmission plant to both the SC and PS classes[56] or whether Centra is proposing to both direct assign transmission plant as well as a general allocation of remaining transmission plant using a CP allocator[57].

Notwithstanding the lack of clarity regarding Centra's proposal, the following perspectives and recommendations with respect to direct assignment of transmission plant to those classes are provided in Section 8.3 below.

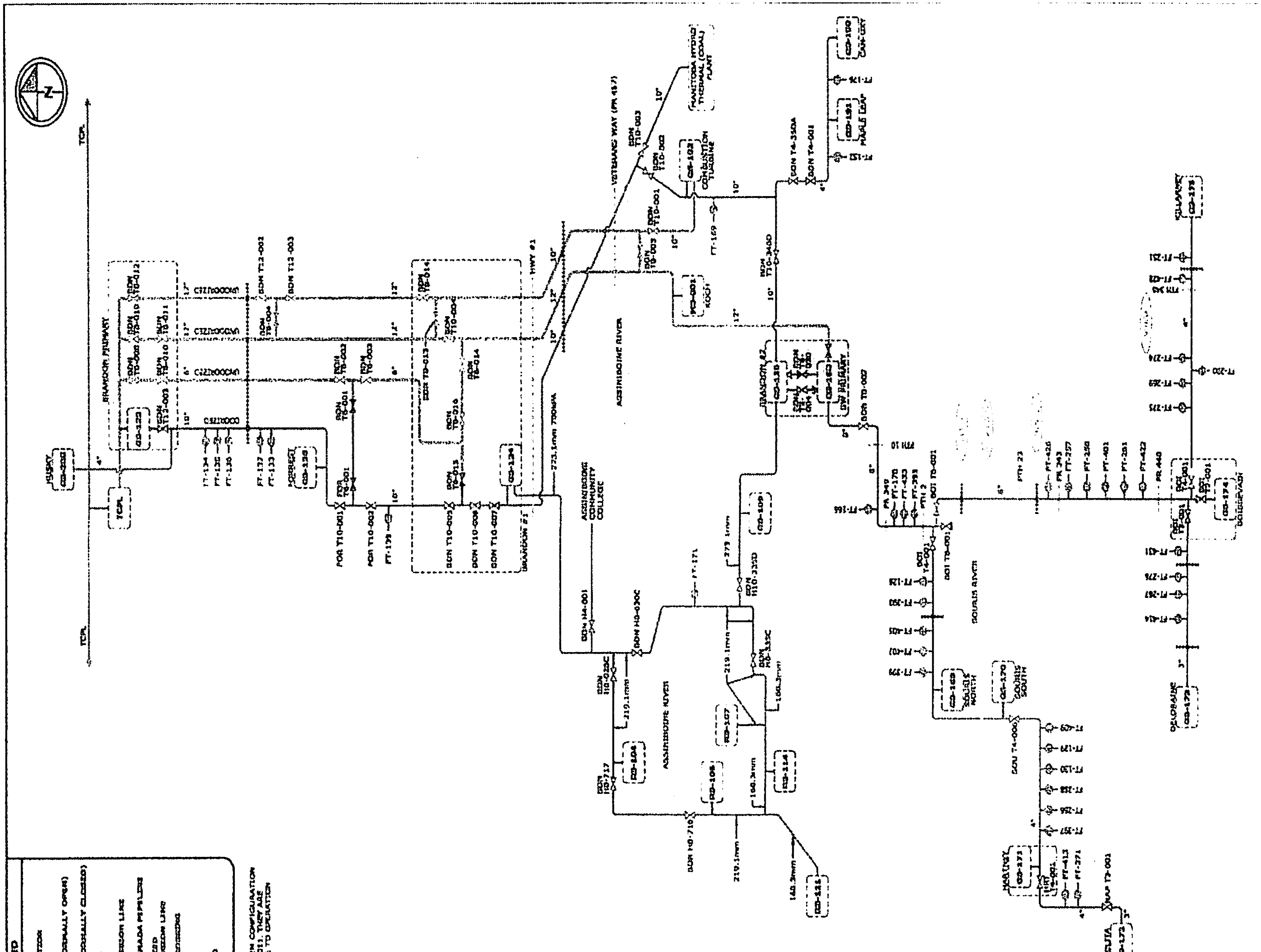
[55] Centra Application, page 32
[56] CAC/Centra 11e f
[57] CAC/Centra 8b-d

8.3 It is Recommended that the SC and PS Classes Continue to Receive a Broader Allocation of Transmission as the Brandon/Southwest Area System Continues to be Integrated under a Broader view of Cost Causation Consistent with the PUB's Policy

The transmission plant that Centra is now proposing to direct assigned to the SC and PS classes are all part of an integrated system serving not only Brandon, but other large customers (such as Maple Leaf, Canada Oxy, Assiniboine Community College, Husky), and the Southwest Manitoba (Malita, Hartney, Souris, Deloraine, Boissevain and Killarney). This system physically runs along a public right of way.

The schematic provided in the Atrium Report itself, at page 18 and by Centra in response to a number of information requests is only an excerpt of the overall system and not reflective of the full schematic of the Brandon and Southwest area system.

In considering this issue, it is important the PUB review the full schematic of the Brandon and Southwest area system provided below, as included in the Atrium Report Appendix A, page A-9:



LEGEND

- GATE STATION
- VALVE (NORMALLY OPEN)
- VALVE (NORMALLY CLOSED)
- FARM TAP
- TRANSMISSION LINE
- TRANS CANADA PIPELINE
- UNODORIZED TRANSMISSION LINE
- WATER CROSSING
- ROAD
- RAILROAD

NOTE:
VALVE POSITION & SYSTEM CONFIGURATION ARE AS OF SEPTEMBER 2011. THEY ARE SUBJECT TO CHANGE DUE TO OPERATION REQUIREMENTS.

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2014-04	ADDED UNODORIZED LINE DESIGNATION	C.A.		
2	2016-08	ADDED FARM TAP 178, 409, 413 & 414	H.A.	C.A.	D.P.
3	2017-09	UPDATED VALVE BOI T4-001 & ADDED FARM TAP 422	C.A.	A.A.	L.G.
4	2019-04	ADDED FARM TAP 428 & 426, UPDATED PTH 346	H.B.	K.M.	K.M.
5	2020-10	CLOSE T6-001, ADD FT 431, 433 & 280 REMOVE FT-138	H.B.	K.M.	K.M.

BRANDON

GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GB-91110-0002	0001 OF 2	05

Centra states in its Application that:

> "Gas **pipeline infrastructure** systems, such as the one serving the City of Brandon, are **highly interconnected systems** consisting of plant assets that are **not considered to function independently** of each other. Such **systems are managed** with the understanding that **changes to** one aspect of the system will typically **impact other aspects of the system** with **respect to performance or redundancy considerations**."[58]

As Centra concedes, the Brandon/Southwest area system is a highly integrated system. Since it was first built in the mid 1950's, there have been a complicated series of subsequent changes in 1974, 1988, 1996, 2001 and 2009[59].

The Brandon/Southwest area system, clearly for many decades has been an integrated asset that has been funded by all customers. It is also important to recognize that the SC load growth for the last 25 years have been met either through available transmission capacity provided by the Brandon/Southwest area system or through the addition of capacity, without the requirements of a customer contribution from the SC customer, and the costs were rolled into rates funded by all customers[60]. With respect to the PS class, contributions have been provided to incrementally fund the addition of capacity. However, the PS feasibility tests, the true-up as well as the minimum margin guarantee are not in scope of this proceeding and therefore, such matters remain unresolved.

As can be seen in the above Brandon/Southwest area schematic, both the SC and PS are connected to the larger system. While some engineering changes have been made to optimize the system, the costs of which have been funded by all customers, this does not result in a situation where it is abundantly clear that the facilities are dedicated to only those customers. In situations where the clarity regarding dedicated facilities is questionable and debatable, then cost allocation practice is such that these assets continue to be viewed as common, comingled, integrated, and allocated to all customers (who have funded the facilities), consistent with the postage stamp ratemaking framework.

Stated simply, once an omelette is scrambled, its not possible to unscramble it, which Centra is now asserting can be done to justify its proposal for direct assignment of transmission plant.

Contrary to Centra's assertion, the broader definition of cost causation as per PUB COS policy, is not limited to the current configuration of an asset[61] and normal operating conditions asserted by Centra[62]. In fact, the PUB's broader definition of cost causation requires "consideration of all of the uses and benefits of an asset, to recognize the primary and secondary benefits of an asset influence the planning and justification of assets. These considerations should be assessed over a range of years (as opposed to a single forecasted year) and over a range of conditions in order to capture all of the uses and benefits of an asset in determining cost causation."[63]

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[58] Centra Application, page 31
[59] CAC/Centra 11 a
[60] CAC/Centra 11 d
[61] CAC/Centra 11 b
[62] CAC/Centra 11 c
[63] Order 164/16, page 27

Based on this broader definition, it is appropriate to consider the long-standing integrated nature of the Brandon/Southwest area system and operating conditions that extend beyond normal operating conditions assumed in a test year. The clarity that is necessary to directly assign the transmission plant to the SC and PS classes does not exist. Accordingly, it is recommended that the PUB retain the current approved methodology to allocate common costs to all customer classes, including the SC and PS classes without a direct assignment. On this basis and to the extent possible, the methodology for cost allocation purposes should be consistent among customer classes.

8.4 It is Recommended that No Interim Rate Adjustment be Made for the Special Contract Class as Centra's Customer Impact Analysis is Incomplete, Outdated and Unreliable for Rate Setting Purposes

Centra states that it is not proposing rate changes as a result of this Application as rate changes typically occur as part of a GRA. Centra also took the position in its process submission leading to Order 36/22 that its COS methodology should be evaluated on its own merits, and as such, the class impacts of the allocation methods should not be a focus of this review or influence any Party's position on the issues within the scope of this proceeding.

Somewhat surprisingly, Centra relies on the illustrative customer class impacts to propose an interim measure to immediately adjust current rates for the Special Contract and Power Stations classes.[64] Centra's proposal is to decrease the SC class rates to the level of non-gas costs in effect prior to the 2019/20 GRA resulting in an $830,000 adjustment to be reallocated/recovered from the PS class. If this interim rate reduction is approved by the PUB, it would be necessary for it to be reviewed and approved or varied at the next GRA.

While intervenors were not provided with access to the information that underlies the derivation of the indicative customer class impacts as provided in Figure 10 and Figure 11 of Centra's Application, our basic understanding of that information is as follows:

1. Some of Centra's proposed changes have been reflected in the indicative class impacts;
2. Centra provides proxies for some its proposed changes where additional analysis is required in order to implement the proposed change; and
3. Some of the proposed changes have not been reflected in the indicative class impacts at all.

The data set used in Figure 10 relates to the 2019/20 GRA which the PUB found in Order 36/22 as out of date for purposes of rate setting[65].

[64] Centra Application, page 39
[65] Order 36/22, page 14

Our observations and recommendations regarding the interim rate reduction are provided as follows:

1. The fact that these indicative customer class impacts have been ruled by the PUB to be out of scope but remain on the public record, may be viewed as prejudicial to interested parties. To rule this matter out of scope but leave this information on the record is tempting for parties to be influenced by the indicative results but without the ability to test and make arguments as to their veracity; and
2. There are several problems with this proposal:

   i. Centra is placing reliance on an incomplete and outdated set of calculations in order to propose the general level of its interim adjustment;
   ii. It is obvious that Centra is placing reliance on the $1.229 million from the indicative customer class impacts in order to have confidence that the $830,000 adjustment would not be excessive;
   iii. By relying on unreliable indicative class impacts, the potential exists that the interim rate reduction would need to be recovered from the SC class at the next GRA; and
   iv. Centra's interim rate measure relies on rates prior to the 2019/20 GRA, and based on the 2013/14 GRA, nearly a decade ago, and such a measure would constitute retroactive ratemaking.

For these reasons, it is recommended that no interim rate adjustment be made as a result of this proceeding. The PUB has ruled that the 2019/20 GRA revenue requirement and COS is inadequate and outdated. As such, the indicative class impacts in Figure 10 and Figure 11 cannot be relied upon for setting rates whatsoever. Any rate adjustment that may flow from COS changes is appropriately implemented as part of Centra's next GRA, once the PUB's directives flowing from this proceeding are known, the updated test year data and any changes to the COSMR have been implemented into the COS model and tested in a public hearing by the PUB and Intervenors.

Further, if the PUB approves any changes flowing from this proceeding, it is recommended that Centra be directed to file two COS studies at the next GRA, one that reflects all the COS changes as well as the updated revenue requirements, and one that excludes the COS changes such that the impacts as a result of the COS changes can be isolated and tested.