REFERENCE:

Section 1.0, page 5 (lines 23-27)

PREAMBLE TO IR (IF ANY):

Centra states:
"Cost causation may be the dominant factor in determining the appropriate level of rates for a class of customers, but it is not the only factor to be considered. Since at least 1996, Manitoba has recognized "non-cost causal" factors in the setting of fair and reasonable natural gas distribution rates. Rates may be considered to be fair and equitable when they reasonably reflect the costs incurred to provide the service." (Application, page 5)

QUESTION:

a) Please explain Centra's policy drivers that are influencing its proposed changes to cost allocation methodology.

RESPONSE:

Fundamentally, Centra's proposed changes to cost allocation methodology are to ensure that its cost allocation study best reflects cost causation and therefore continues to be a useful tool in the rate making process. A utility's cost structure is not static and evolves over time which can necessitate changes to allocation methodologies.

Centra's 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.

REFERENCE:

Section 1.0, page 5 (lines 23-27)

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide Centra's views as to whether its cost allocation proposals are consistent with the transformational and disruptive forces that are changing the energy sector terms of decarbonization, decentralization, deregulation, democratization and digitization.

RESPONSE:

As noted decarbonization, decentralization, democratization, and digitization are expected to be both transformational and disruptive. Such forces are expected to require updates to a utility's rate designs and strategies in order to achieve desired rate objectives. While Centra's proposed changes to cost allocation are not aimed at specifically addressing any particular one of these forces, they will make Centra's cost of service more transparent by removing non-cost causal considerations thereby better facilitating the achievement of any desired rate objectives during the rate design phase.

REFERENCE:

Section 1.0, page 5 (lines 23-27)

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please explain how Centra's cost allocation proposals that shift cost responsibility based on demand only rather than based on demand and volumes are consistent with the societal and organizational imperative of decarbonization and the ability to influence customer behaviour through Centra's ratemaking practices including cost allocation.

RESPONSE:

Fundamentally, Centra's cost allocation proposals appropriately shift cost responsibility to better reflect cost-causation principles rather than attempting to influence certain customer behaviours. Given the nature of a Gas LDC, in a cold climate such as Manitoba, the vast majority of costs, excluding purchased gas and variable transportation, are related to having the available capacity required to meet customer's needs during peak conditions.

While the current cost allocation methodology includes a larger volumetric component that may be considered directionally consistent with the goal of encouraging decarbonization, using implicit adjustments in attempting to influence customer behaviour to address the issue of decarbonization is not the preferred approach as:

- It is more difficult to identify and quantify the price signal that is included in rates when it is accomplished by incorporating equity considerations at the cost allocation stage.
- Adjustments to the cost allocation methodology are unlikely to achieve the optimal level of price signal. Future climate policy may require additional rate measures to achieve decarbonization goals or may make the implicit signal redundant if external factors such as carbon tax are deemed to provide a sufficient signal.

- Explicitly incorporating any policy considerations into the rate design stage will allow Centra to measure, evaluate and adjust the price signal as needed without the need to modify the cost allocation methodology.

Centra’s cost allocation proposals do not impede its ability to influence customer behaviour through rate making practices but rather provide a better indication of which behaviours would result in a reduction of costs not just for customers but also for Centra.

REFERENCE:

PUB Orders 107/96, pages 26- 27, 164/16, page 27

PREAMBLE TO IR (IF ANY):

In Orders 107/96 and 164/16, the PUB stated:
"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" **PUB Order 107/96, pages 26 to 27**

"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. This methodology is to apply to assets currently in service, as well as future assets, such as Keeyask and Bipole III. 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 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." **PUB Order 164/16, page 27**

QUESTION:

a) Please explain if Centra disagrees with the PUB's definition of cost causation as reflected in its findings in Orders 107/96 and 164/16 as noted in the preamble above. If Centra disagrees, provide an explanation as to the basis for its deiagreement.
b) Please explain if Centra's cost allocation proposals in its the current Application are consistent with the PUB's findings related to the definition of cost causation.

RESPONSE:

a) Centra agrees with both of these statements.

b) Centra's proposals in this Application are consistent with the PUB's findings in 107/96 and 164/16.

REFERENCE:

Section 2.1, page 5, lines 23–26, MFR 8, Attachment 1, pages 32-33, Attachment 2, page 13

PREAMBLE TO IR (IF ANY):

Centra states: (2022)
"Cost causation may be the dominant factor in determining the appropriate level of rates for a class of customers, but it is not the only factor to be considered. Since at least 1996, Manitoba has recognized "non-cost causal" factors in the setting of fair and reasonable natural gas distribution rates. Rates may be considered to be fair and equitable when they reasonably reflect the costs incurred to provide the service" **Application, page 5**

Christensen Associates states: (2012)
"Centra's application of the peak-average allocation methodology rests on solid institutional precedent. One well-known method is the Atlantic Seaboard formula, where facility costs are allocated according to peak day and energy throughput, each weighted by 50%. Another method is the United formulation (United Gas Pipeline, 1973), in which the weights are 25% and 75% for peak day and energy, respectively. For pipelines, the Federal Energy Regulatory Commission adopted the so-called Modified Fixed Variable approach during the 1980s. All three cost allocation methods are variations of peak day-average throughput combination allocators. Moreover, the Gas Distribution Rate Design Manual of the NARUC describes the average and peak method (i.e., peak-average) as one of the most commonly used approaches for allocation of demand-related (fixed) costs (at page 27).

However, discussions with planners and general intuition suggest that transport costs are driven largely by peak demand and transport distance (line length), and secondarily by the type of terrain and factors associated with infrastructure density. Peak day demand (maximum daily throughput) is an observable causal factor for cost allocation. However, length of transmission and distribution mains attributable to customers is less observable and it is also difficult to associate distance measures with customers or customer classes because of practical and institutional limitations. As a consequence, to the degree that transport distances are accounted for in cost allocation, it is necessary to utilize surrogate allocation metrics.

One potential surrogate metric for length of mains is number of customers. MH could evaluate this idea by estimating the shares of total costs of mains attributable to: 1) peak capacity (“max day”) and 2) line distances. The share attributable to max day would be allocated according to peak day responsibility, and the cost share attributable to transport distances (line length) would be allocated according to class number of customers. Another potential surrogate is energy sales, a metric currently in use. Energy use makes sense as a proxy if the average energy per customer, for customers taking service from Centra’s distribution system, does not vary much (i.e., there is fairly homogenous consumption per customer.) If this is true, energy would capture the average/typical distance of mains (that is, the expected value of distance per customer) about as well as number of customers served. Under such a condition, even under strict cost causality, Centra would have good reason to retain its peak-average allocation metric.

Recommendation. For the reason of institutional precedent and recognizing the difficulty of incorporating transport-related metrics by rate class, we support Centra’s peak-average demand allocator for transmission and distribution. However, it may be useful to investigate a peak-customer allocation metric for future consideration, as peak day and transport distance are likely the key cost drivers of transport services. Proxies for distance metrics may be investigated for both transmission and distribution services. Detailed recommendations are as follows:

• **Transmission and Distribution**. If cost causation is the paramount criterion for selection of an allocator, then Centra may wish to explore the development of a combination allocation metric that includes maximum day and number of customers.

• **Combination allocator weights.** Under certain conditions, energy can serve as a useful surrogate to capture the underlying cost factors that drive the costs of distribution facilities. We recommend that Centra explore whether load factor conforms adequately to the impacts of the underlying two main cost drivers (peak day, distance) on facility costs. As a consequence, we recommend that Centra consider conducting a cross-sectional statistical analysis of costs and cost drivers, reflected in historical work order records. **MFR 8, Attachment 1, pages 32-33**

Centra states: (2012)
Recommendation 27: With respect to the Peak and Average demand allocator, CA supports the continuance of this demand allocator for Transmission and Distribution. CA goes on to state that Centra consider the investigation of a peak-customer allocator alternative (page 30).

Centra's Position and Rationale: Centra is supportive of the continuance of a peak and average approach for the allocation of demand related costs as endorsed by the CA. Centra is of the view that the peak and average methodology has served the utility well, is recognized in industry as a well-founded allocation approach that gives a balanced weight to the objectives of economic efficiency and fairness in that it gives recognition to the use of the system, is simple, and provides an objective basis for the determination of rates. Centra accepts CA's perspective that peak demand and length of pipe are likely key drivers of cost. However, Centra is of the view that:

1. Given the distribution of customers in Manitoba, it is not apparent that customer count is a reasonable proxy for distance; and
2. With respect to Distribution Plant, Customer numbers are considered at the Classification Phase (through its diameter-length study).

For these reasons as well as that this approach not employed elsewhere, Centra does not intend to pursue further study of the use of customer as a proxy for distance." **MFR 8, Attachment 2, page 13**

QUESTION:

a) Please explain the changes in circumstances that have caused Centra to reverse its earlier policy position (1996 and 2012) that cost causation is driven more than by the costs incurred in providing service at the peak day.

RESPONSE:

Centra has not reversed its position with regards to cost causation as suggested in the preamble. It is well documented through Centra's applications that the peak and average allocator is not purely cost causal. In response to PUB/CENTRA I-106 in the 2009/10 and 2010/11 GRA Centra stated:

> *"The Peak and Average method considers two factors in the allocation of capacity costs to each respective customer class. As the title suggests, the class' contribution to the system peak day is one component, and the class' respective share of total annual system throughput is the other component. This allocator reflects cost causation to the extent that capacity is designed from a gas supply perspective to meet the peak day requirements and the peak component is recognized. The allocator is not purely cost-causal in nature, as the use of the average component reflects some customer-to-customer equity considerations in that higher load factor customers use the system with more intensity than do lower load factor customers.*
>
> *Other possible allocation methodologies include the pure coincident peak methodology in which capacity costs would be allocated solely on each customer class' contribution to the coincident demand on the system's peak day. This would be a more cost causal approach than the current peak and average method, as it considers only demand or peak contribution and does not incorporate any consideration of average annual usage.*

Centra's proposals in this Application better reflect pure cost-causal principles and the PUB's views from Order 164/16 that non-cost causal considerations are best incorporated at the rate design stage rather than embedded in cost allocation.

REFERENCE:

Section 2.1, page 5, lines 23–26, MFR 8, Attachment 1, pages 32-33, Attachment 2, page 13

PREAMBLE TO IR (IF ANY):

Centra states:
"The PUB approved the proposed Cost of Service Methodology changes with the issuance of Order 107/96. While there have been some modifications to the Cost of Service Methodology in the ensuing years, as well as a subsequent assessment by Christensen and Associates completed in 2010 as part of their review of Manitoba Hydro's Cost of Service Study for the electric operations, the underlying methodological approach has remained relatively unchanged." **Application, page 1**

QUESTION:

b) Please summarize the most significant changes in circumstances since 1996 and 2012 that gave rise to Centra's current proposed cost allocation methodology changes, including changes in system planning, operations, and customer service requirements.

RESPONSE:

As detailed in CAC/CENTRA I-11 a) there have been several changes to the Brandon-area pipeline system which now result in both the Special Contract and Power Station being served by dedicated pipelines. This, along with the varied and often limited use of the Power Station class and the Interruptible class not being curtailed for downstream purposes, are the most significant changes influencing Centra's proposals.

REFERENCE:

Section 2.1, page 5, lines 7-15, lines 23-24, Section 3.0, page 26, lines 16-17, Section 4.1.1, page 30, lines 18-20, Section 5.0, page 37, lines 3-9

PREAMBLE TO IR (IF ANY):

Centra states:
"Centra's Cost of Service Methodology and approach to rate design are driven primarily by cost causation…. there can be a wide range of methodologies that are considered to reasonably reflect cost causation….. the methods used to apportion costs should consider the operating characteristics, reasons for investment, and business practices of the utility." **Application, page 5, lines 7-15**

"Cost causation may be the dominant factor in determining the appropriate level of rates for a class of customers, but it is not the only factor to be considered. Since at least 1996, Manitoba has recognized "non-cost causal" factors in the setting of fair and reasonable natural gas distribution rates." **Application, page 5, lines 23-24**

"A balance must be struck to produce customer classes and rate structures that are both fair and reasonable while remaining simple and practical enough to enable efficient and effective implementation for billing purposes." **Application, page 26, lines 16-17**

QUESTION:

a) Please reconcile Centra's stated ratemaking objectives as outlined in

i) Section 2.1 - there can be a wide range of methodologies that are considered to reasonably reflective of cost causation and cost causation may be dominant factor in determining the appropriate level of rates but not the only factor to be considered; and ii) Section 3.0 - a balance must be struck to ensure rates are fair, reasonable, simple, practical, efficient and effective with the statements made in Sections 4.1.1 (Centra supports a transition to a more pure cost causation approach) and Section 5.0 (cost of service is more transparent when non-cost causal factors are excluded).

RESPONSE:

Centra's rate making objectives are not irreconcilable. Rather, the quoted statements reflect the fact that the cost of service stage and the rate setting stage are two separate and distinct steps in the overall rate making process. The output of the cost of service study is used as a tool in determining the rate design and rates for each of the different customer classes. The multi-staged approach to rate making is further described at page 16 of Order 164/16.

In section 2.1, Centra recognizes that there are differing opinions when it comes to determining cost causation and that there may be more than one reasonable method of apportioning costs.

Section 3.0 recognizes the fact that it is not feasible to develop specific rates that recover the exact cost to serve each customer and as a result, the utility must make choices when grouping customers to create customer classes that will allow it to allocate costs and design rates that limit inter and intra class subsidies to the extent practical.

The referenced quotations from section 4.1.1 and section 5.0 reflect Centra's position that removing non-cost causal considerations from the cost of service study is an improvement that provides better insight into how rate objectives are reflected when they are incorporated at the rate design stage rather than at the cost allocation stage. This view is consistent with the Board's position from Order 164/16; *"The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage."*

REFERENCE:

Section 2.1, page 5, lines 7-15, lines 23-24, Section 3.0, page 26, lines 16-17, Section 4.1.1, page 30, lines 18-20, Section 5.0, page 37, lines 3-9

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Further to PUB/Centra IR 1-21, please also provide and explain Centra’s current ratemaking objectives and how those objectives have been specifically applied to each of Centra’s cost allocation proposals.

RESPONSE:

Centra’s cost of service proposals remove non-cost causal considerations such as rate making objectives from the cost allocation stage and as such, Centra’s rate making objectives have not been applied to its cost allocation proposals.

REFERENCE:

Section 2.1, page 5, lines 7-15, lines 23-24, Section 3.0, page 26, lines 16-17, Section 4.1.1, page 30, lines 18-20, Section 5.0, page 37, lines 3-9

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please explain how Centra has reflected and weighted the following considerations (as noted in the above preamble) as part of its cost allocation proposals:

   i) Operating characteristics;
   ii) Reasons for investment; and
   iii) Business practices

RESPONSE:

Centra does not ascribe a specific weighting to the relative importance of operating characteristics, reasons for investment or business practices when assessing its cost allocation methodologies but rather recognizes that each one of those items may be more or less relevance when assessing cost causality or the feasibility of implementing the cost allocation methodology for a particular cost.

REFERENCE:

Section 1.0, page 2, lines 9-13

PREAMBLE TO IR (IF ANY):

Centra states:
"Atrium met with Centra's subject matter experts in order to gain an understanding of Centra's gas transmission and distribution system operations and engineering practices, to review the physical configuration of the system, and to discuss the procurement of gas commodity and capacity-related resources from upstream suppliers." **Application, page 2**

QUESTION:

Please explain if Centra engaged with its customer groups, external stakeholders or intervenors, in advance of the finalization of its cost allocation recommendations and the filing of this Application? If yes, please explain which parties Centra engaged with, the dates, and provide a summary of the outcome of those discussions. If not, please explain why not.

RESPONSE:

Centra did not meet with external stakeholders or intervenors since the 2019/20 GRA when intervenor positions were well known as articulated in their respective evidence and extensively canvassed and reviewed as part of that proceeding and the filing of the Application. Those positions were carefully considered by both Atrium and Centra as part of the Application as requested by the PUB.

Furthermore, due to the technical nature of cost allocation, Centra is of the view that engaging with customers is most appropriately done at the rate setting stage as opposed to the cost allocation stage which involves determining suitable methods for apportioning the costs of operating its natural gas system among its customer classes.

REFERENCE:

Appendix 1, page c-1

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide Centra's perspectives and conclusions regarding the Atrium Canadian LDC research conducted as summarized in Section 8.0 and Appendix C of the Atrium Report including 1) is there a range of acceptable methods for the allocation of costs 2) is the use of non-cost causal factors prevalent in cost allocation methods in Canadian LDC's and 3) is there precedent for direct assignment of transmission cost to large volume customers?

RESPONSE:

As is documented in most cost allocation studies and literature, there is a wide range of acceptable methods for the allocation of costs dependent upon specific circumstances. Atrium's review of Canadian LDC's is consistent with this notion.

It is more difficult to discern whether the utilities consider there to be non-cost causal items in the study as that would require making an interpretation of filings, board orders and transcripts. Similarly, determining whether there is precedent for direct assignment of transmission to large volume customers would require a more nuanced understanding of each of the utility's specific circumstances. Instances of direct assignments would be very specific to both the customer in question and the utility providing the service and may not be explicitly reflected in the Cost of Service Study. For example, Fortis excludes their Special Contract customers from their cost allocation studies which implies that there are assets directly assigned to those customers.

REFERENCE:

Section 2.3.2, page 18, lines 25-26

PREAMBLE TO IR (IF ANY):

Centra states:
"Amortization of DSM investment is functionalized to Transmission, classified as Energy and allocated based on forecast customer class participation in DSM programs." **Application, pg 18**

QUESTION:

a) Please explain the purpose and intent for Centra's investment in gas DSM.

RESPONSE:

Prior to the establishment of Efficiency Manitoba ("EM") the investment in gas DSM was viewed as a means of allowing customers to reduce exposure to volatile natural gas prices, and enable Centra to serve domestic load with less energy, resulting in a reduction in the volume of green house gas emissions.

In January 2018 *the Efficiency Manitoba Act* ("*EM Act*") established EM as a corporation with a mandate to:

- implement and support demand-side management initiatives to meet savings targets and achieve any resulting reductions in greenhouse gas emissions in Manitoba;
- reduce consumption of electrical energy and natural gas beyond the savings targets if reductions can be achieved in a cost-effective manner;

- mitigate the impact of rate increases on Manitoba ratepayers through the delay of Manitoba Hydro's need for major capital investments in new generation and transmission projects; and
- promote and encourage the involvement of the private sector and other non-governmental entities in the delivery of its demand-side management initiatives.

On a go forward basis, the purpose of Centra's investment in gas DSM is to fulfill its obligation under the *EM Act* to provide funding necessary for EM to implement its approved efficiency plan and carry out its responsibilities under the *EM Act*.

REFERENCE:

Section 2.3.2, page 18, lines 25-26

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Further to PUB/Centra IR I-3, please explain whether there is any fundamental reason for preferring one cost allocation approach for the other (i.e the allocation of DSM cost based on class participation or a substitute for transmission and distribution investment and thus allocating DSM cost as a system benefit).

RESPONSE:

The marginal values used to evaluate the gas DSM portfolio do not attribute any value to the deferral of future investments in Centra's transmission and distribution system. Instead, the marginal value consists entirely of the benefits related to a reduction in natural gas purchases and transportation.

In absence of any demonstrated benefit from avoided investment in Centra facilities, implementing a system resource approach that allocates DSM as a substitute for transmission and distribution system investment does not appear to reflect cost causation.

Please see Centra's response to PUB/CENTRA I-3 b) and d) for a discussion of the merits of allocating DSM as a system resource.

REFERENCE:

Section 4.1.1, page 29, lines 14-16, Section 5.1, page 38, Figure 10

PREAMBLE TO IR (IF ANY):

Centra states:
"Atrium recommends the exclusive use of a Coincident Peak Day allocation of transmission mains and the demand component of distribution mains. Atrium further recommends the use of Centra's design day peak demand as superior to using an actual peak day demand or an historical average of multiple peak day demands for the purposes of deriving the allocation of demand-related costs of transmission and distribution pipeline facilities." **Application, page 29**

QUESTION:

a) Please clarify whether Centra interprets Atrium's recommendation to exclusively use a CP allocator for purposes of allocating "transmission mains" and the demand component of "distribution mains" or whether Centra's interpretation is to exclusively use a CP allocator for purposes of allocating all plant functionalized as transmission and, similarly all distribution demand-related plant.
b) In the analysis prepared by Centra and summarized in Figure 10 of its Application, did Centra apply a CP allocator to all plant functionalized as transmission and the demand component of distribution plant or just to transmission and distribution demand-related mains? Please explain.
c) If in the analysis as summarized in Figure 10 of Centra's Application, Centra has applied a CP allocator to only transmission and distribution-demand mains, please refile Figure 10, along with all the relevant supporting schedules (redacted for CSI as necessary) assuming that the CP allocator is used to allocate all transmission and distribution demand-related plant.

d) If in the analysis as summarized in Figure 10 of Centra's Application, Centra has applied a CP allocator to only transmission and distribution-demand mains, please explain how the remaining transmission plant and distribution demand-related plant has been allocated and provide Centra's rationale.

RESPONSE:

a) Centra's proposed methodology reflects the use a CP allocator for all transmission and distribution plant classified as demand. This is consistent with Atrium's recommendation.

Response to parts b) through d):

Figure 10 of the Application first reflects a direct assignment to the Power Station and Special Contract classes from the transmission mains costs. All remaining transmission plant costs were allocated using a CP allocator. Figure 10 also reflects all distribution plant classified as demand allocated using a CP allocator.

REFERENCE:

Section 4.1.1, page 29, lines 14-16, Section 5.1, page 38, Figure 10

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please explain the level of Centra's coincident factor (i.e. measuring the coincidence between the system coincident peak and non-coincident peaks) and whether its coincidence factor tends to be high or low.

RESPONSE:

As Centra does not track or record the individual peaks for SGS and LGS customers on its system, this information is not available. Given the predominance of heating load, however, Centra expects the coincidence factor of its system to be high.

REFERENCE:

Section 4.1.1, page 31, lines 22-28

PREAMBLE TO IR (IF ANY):

Centra states:
"To reliably meet the requirements of all customers, the transmission and distribution system must be able to supply the peak demand on the system. Design Day corresponds to the day with the highest coincident system peak conditions that the system is designed to meet under extreme weather conditions. As Centra uses a peak design hour approach for planning purposes, a Design Day metric by customer class is currently not available. As this metric will take time to develop, the illustrative impacts of the recommendations in Appendix 4 utilize the current peak day definition, as developed for…"

QUESTION:

a) Please explain whether Centra has used a design day allocator for purposes of the PAVG allocator since the 1996 cost allocation methodology review and if it has, please provide its rationale for having moved to the current peak day definition.

RESPONSE:

Centra has been using the same methodology to calculate the "peak" portion of its peak and average allocator since Centra was acquired by Manitoba Hydro in 2001. For cost allocation purposes, despite the "peak" having been referred to as either the "Design Day" or "Peak Day", since 2001 the "peak" has represented the coldest day expected in the test year. Centra is unable to definitively confirm if that calculation methodology was different than what was used prior to 2001 although from the narrative descriptions contained in the 1996 cost allocation methodology review that appears to be the case.

REFERENCE:

Section 4.1.1, page 31, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Further to PUB/Centra IR I – 9, please explain how Centra determines the peak design hour (without disclosing CSI) for the system and each class and whether its determination changes over time along with the frequency of change.

RESPONSE:

Please see the response to PUB/CENTRA I-9d.

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

Centra states:
"In part, this treatment was deemed necessary as it was assumed that Interruptible customers were being curtailed at the time of system peak. Without incorporating usage into the allocation of capacity costs, the Interruptible Class would not have contributed to the recovery of any capacity costs." **Application, page 30, Emphasis Added**

"With the evolution of Centra's system and the Interruptible Class, there are allocation methods other than Peak and Average that can be used while still ensuring cost recovery from all users of the system."

"First, the Interruptible Customers use Centra's distribution system to receive Alternate Supply even while being curtailed for upstream capacity factors. Second, Centra includes the Interruptible Class capacity requirements in its downstream capacity planning criteria."

QUESTION:

a) Centra states that one of the reasons that it moved to a PAVG methodology is that it addressed the concern that interruptible customers would not otherwise contribute to the recovery of any capacity costs. Please explain the other factors that lead to Centra's adoption of the PAVG methodology.

RESPONSE:

Centra adopted the Peak and Average allocator after its 1996 Cost of Service Methodology Review. At the time of adoption the following factors were identified as influencing Centra's position: Peak and Average recognized the utilization of the system as an explicit factor to be included in determining cost responsibility;

- Peak and Average is relatively simple and straightforward;
- Peak and Average is a widely accepted method of cost allocation;
- Peak and Average is considered cost-causal in many state and provincial jurisdictions; and
- Peak and Average produced results that were close to the PUB's approved class revenue requirements at the time.

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a detailed discussion of the evolution of Centra's system that has driven Centra to propose a move away from the longstanding PAVG methodology.

RESPONSE:

As noted in its Application (page 30, lines 18-20) and in CAC/CENTRA I-3 a), Centra's proposal to move away from the PAVG methodology is to better reflect a more pure cost-causal approach at the cost allocation stage.

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please explain why (and when) Centra began to include interruptible class capacity requirements as part of its firm downstream capacity planning criteria. In response, please also provide a summary of Centra's cost benefit analysis and conclusions to support this decision.

RESPONSE:

The customer loads of interruptible class customers have been included in the distribution system peak firm capacity planning criteria since at least 1997. Alternate Supply Service permits interruptible customers to maintain natural gas service during curtailment for upstream capacity factors. They pay a market rate for gas commodity and the Alternate Supply Service delivery charge. Centra's distribution system supports the interruptible load if these customers elect Alternate Supply Service, which has been available since at least 1997.

Centra has not been able to determine if a cost benefit analysis was performed at the time this approach was implemented over 25 years ago. However, the interruptible class reduces the amount of upstream transportation capacity for which Centra must contract, thereby reducing costs while maintaining gas service for Interruptible customers through Alternate Supply Service (if available).

At this time, Centra has a total of 21 interruptible class customers, comprised mainly of institutional entities like hospitals and personal care homes; 5 of these 21 customers are seasonal operations that do not impact Centra's winter peak.

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please explain what conditions, if any, would lead to curtailment, downstream (i.e in Centra's system) of the interruptible class given that it now plans for and designs its system assuming all customers are firm.

e) Please explain i) what value, from a downstream perspective, that interruptible customers provide to firm system customer requirements such that it is appropriate for the continuance of an interruptible class and ii) the downstream cost to serve differences of interruptible customers that necessitate the continuation of a separate class.

RESPONSE:

d) Curtailment of interruptible customers in Manitoba would occur if available gas supply from the TransCanada Pipelines ("TCPL") Mainline or Centra's distribution system was insufficient to meet Manitoba gas demand due to an operating issue such as pipeline damage or if Manitoba gas demand was exceeding available capacity on Centra's distribution system. Accordingly, curtailment of interruptible customers may help maintain service to firm customers under some operating conditions.

e) Under Centra's proposed cost allocation, the continuance of the interruptible class is not predicated on the need to provide value from a downstream perspective to other customer classes; as long as costs are properly allocated, there is no impact to firm customers. Centra's proposed cost allocation ensures the interruptible class is appropriately bearing its share of both upstream and downstream costs. Interruptible customers continue to receive the benefit of lower upstream costs based on the level of risk they are willing to assume and for this reason, the continuation of the interruptible class is warranted.

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

f) Please provide an updated Figure 10, along with all the supporting schedules that merges each interruptible customer into the appropriate firm class (HVF, Mainline or LGS) consistent with each current interruptible customer service requirements. Please also provide all assumptions made and a rationale for the outcome.

RESPONSE:

Based on the connection to Centra's system and 2018 load characteristics, the Interruptible class would primarily belong to the HVF class. When preparing the requested scenarios, Centra reflected the movement of all Interruptible customers to the HVF class in volume, customer numbers, demand units, and the coincident peak. All allocation factors as well as external studies used in the allocation of O&A costs, Supplemental Gas and UFG were adjusted to reflect the inclusion of the Interruptible volumes, customer numbers, demand units and coincident peak in the High Volume Firm class.

Centra did not alter the input costs, rather approved costs were re-allocated. This does not provide an accurate result rather is directionally indicative because if the INT class were to actually be "firmed up" there would be related changes in the gas supply portfolio and costs (specifically, an increase in upstream transportation capacity and cost). However, the analysis does provide an indication of how costs could shift if the INT class were to be discontinued.

Figure 10.1 below compares the allocation of the total Cost of Service to various customer classes resulting from the approved and the proposed methodology, both reflecting the Interruptible class entirely merged into High Volume Firm class.

Figure 10.1

Allocation Results of Revenue Requirement by Class ($000's)			
	2019/20 Test Year Approved Revenue Requirement		
Customer Class	Approved COS Methodology (INT class merged into HVF)	Proposed COS Methodology (INT class merged into HVF)	Increase/ (Decrease)
SGS	$127,886	$129,814	$1,928
LGS	$53,887	$54,810	$922
High Volume Firm	$15,876	$14,115	($1,762)
Co-op	$18	$15	($3)
Mainline	$2,200	$1,738	($462)
Special Contract	$2,265	$1,069	($1,196)
Power Stations	$279	$851	$572
Interruptible	$0	$0	($0)
Primary Gas	$115,089	$115,089	($0)
Supplemental Firm	$11,757	$11,757	$0
Supplemental Interruptible	$0	$0	$0
Fixed Rate Primary Gas	$64	$64	($0)
Total Cost of Service	$329,321	$329,321	($0)

Figure 10.2. below compares the approved allocation of the total Cost of Service to various customer classes to the approved allocation with INT merged into HVF class. Centra prepared this figure to isolate the effect of merging the Interruptible class into the System Supply HVF class from the methodology changes.

Figure 10.2

Allocation Results of Revenue Requirement by Class ($000's)

Customer Class	2019/20 Test Year Approved Revenue Requirement: Approved COS Methodology	2019/20 Test Year Approved Revenue Requirement: Approved COS Methodology (INT class merged into HVF)	Increase/ (Decrease)
SGS	$128,542	$127,886	($657)
LGS	$54,398	$53,887	($511)
High Volume Firm	$13,050	$15,876	$2,826
Co-op	$18	$18	($0)
Mainline	$2,225	$2,200	($26)
Special Contract	$2,299	$2,265	($34)
Power Stations	$280	$279	($1)
Interruptible	$1,599	$0	($1,599)
Primary Gas	$115,089	$115,089	$0
Supplemental Firm	$10,998	$11,757	$760
Supplemental Interruptible	$760	$0	($760)
Fixed Rate Primary Gas	$64	$64	$0
Total Cost of Service	$329,321	$329,321	$0

REFERENCE:

Section 4.1.1, page 30, lines 3-6, 8, 11-14, lines 22-28

PREAMBLE TO IR (IF ANY):

QUESTION:

g) Please explain if and what allocation changes have been made to update the Alternative Supply costs and rates to reflect that interruptible customers are firm on Centra's system.

RESPONSE:

Interruptible customers are not firm on Centra's system. Please see the response to CAC/CENTRA I-10 d) and e).

If the proposed cost allocation treatment to the Interruptible class is approved, Centra intends to propose a change to the formula calculating its Alternate Service rates at the next GRA. The Alternate Service delivery rate would continue to recover the volumetric portion of the charge as it does currently, but the demand portion of the delivery rate would be removed to reflect that capacity costs will be fully recovered from the regular monthly demand charge of the Interruptible class.

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

Centra states:
"While this has not always been the case, Centra's system configuration has evolved and based on conditions assumed in the Cost of Service Study (i.e. normal operating conditions), Centra is able to identify facilities that are used to serve the Special Contract Class exclusively and do not serve load for any other customers. Additionally, the pipelines that serve this customer class predominantly have a one-way relationship with the rest of the system. This 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. Furthermore, given both the customers' inability to utilize other parts of Centra's system from an operating perspective (i.e. the requirement for unodourized gas and high-pressure requirements), Centra supports Atrium's recommendation for a Direct Assignment approach for the Special Contract Class and the Brandon Power Station."

QUESTION:

a) Please explain how Centra's system configuration has changed and evolved overtime such that Centra is now able to identify the facilities to directly assign to the SC and PS classes.

RESPONSE:

Please see Attachment 1 to this response for the Brandon Gas Pipeline Schematic. The evolution of the Brandon Transmission Pressure Pipeline System is summarized in the table below:

Evolution of the Brandon Transmission Pressure Pipeline System					
Line Colour Code (Per attachment)	**Installation Date**	**Pipeline Size (mm)**	**Pipeline Maximum Operating Pressure (kPa)**	**Normal Operating Pressure (kPa)**	**Comments**
Blue	1956, 1988	273, 323	4140	3275 kPa (winter) 2410 kPa (summer)	Natural gas supply is pressure regulated and odourized.
Purple	1974	168	6070	See Note 1	See Note 2
Green	1996	323	6070	See Note 1	See Note 2
Orange	2001, 2009	323, 273	6070	See Note 1	See Note 2

Notes:

1. The pipeline operating pressure follows the available supply pressure from the TransCanada Pipeline to the maximum pressure of 6070 kPa.
2. The supply to the pipeline is not pressure regulated or odourized.

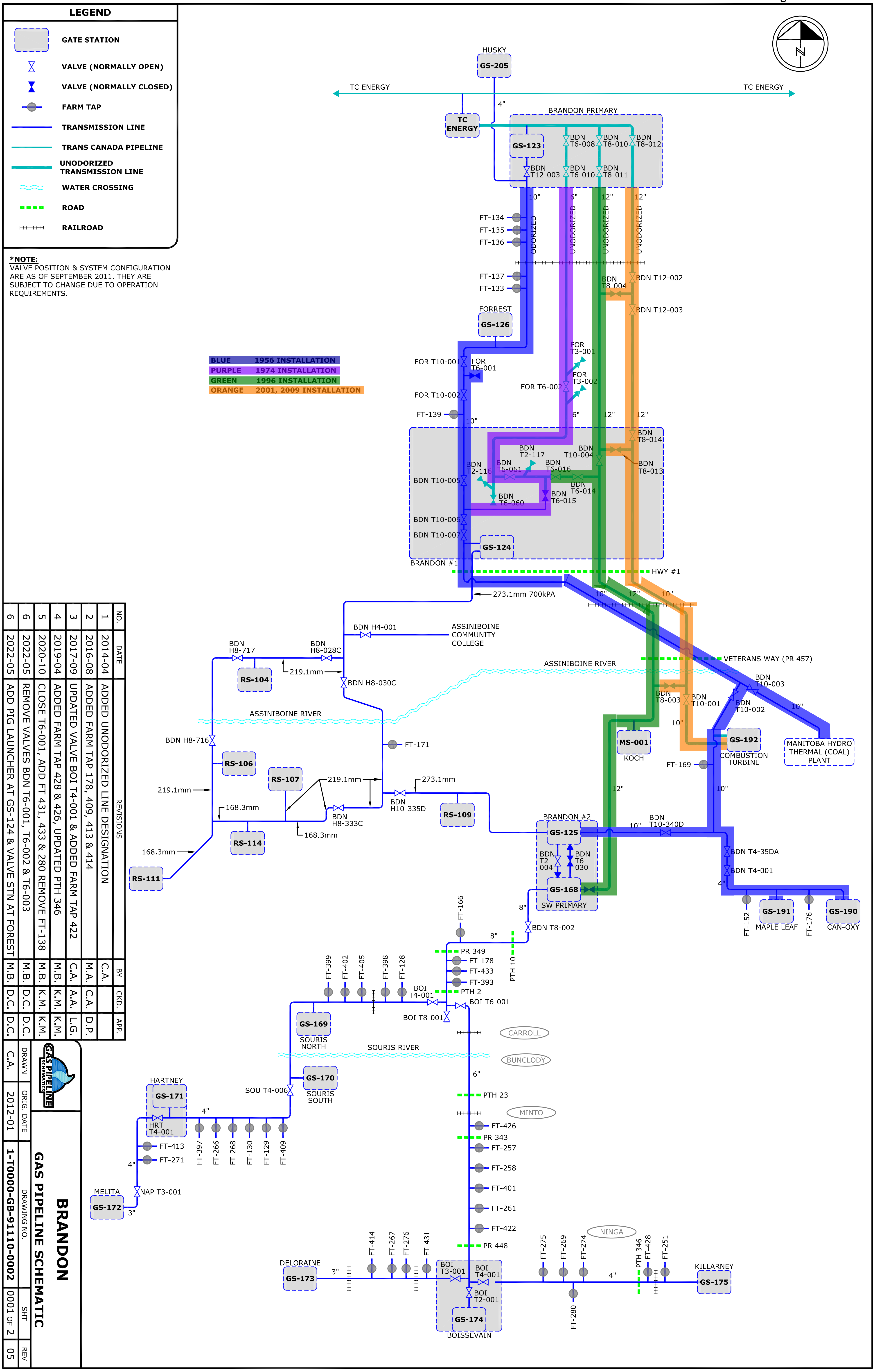
The evolution of the pipeline system generally follows the pipeline construction with some operational changes to meet changing customer load requirements:

- In 1956, the original 273 mm pipeline was built to supply Brandon and the immediate area. In 1965 the 273 mm pipeline was extended from the area of the Manitoba Hydro's thermal plant to GS-125.
- In 1974, the 168 mm pipeline was installed to provide increased capacity for the pipeline system.
- In 1996, a 323 mm pipeline was installed to support a major expansion of the Brandon based Special Contract Class industrial customer and the Southwest expansion project to supply gas to six communities. This pipeline was designed for operation at direct TransCanada Pipeline pressure and without odourization. The Special Contract Class customer has an inlet pressure requirement that exceeds the maximum operating pressure of the 1956 pipeline.
- In 2001, sections of 323 and 273 mm pipelines were installed parallel to the 1996 323 mm pipeline to supply a Power Station in Brandon. The pipeline sections were directly connected to the 1996 pipeline. The new pipeline segments increased

capacity of the 1996 pipeline but could not independently supply the Power Station customer. The pipeline segments were designed for operation at TransCanada Pipeline pressure and without odourization. The minimum design inlet pressure to GS-192, the dedicated Power Station pressure regulation station, is 3790 kPa.

- In 2009, a section of 323 mm pipeline was installed to connect the 323 and 273 mm pipelines installed in 2001. This created a continuous pipeline to fully supply the Power Station customer independently of other pipelines. This pipeline segment was also designed for operation at TransCanada Pipeline pressure and without odourization.
- At some time prior to October 2011, operational changes to the pipeline network were made to support increased gas demand for the Special Contract Class customer. The changes included:
  - Operation of manual isolation valves to isolate the 1974 168 mm line from the 1956 273 mm line and connect the 1974 168 mm line to the 1996 323 mm line.
  - Operation of manual valves at GS-168 to transfer the gas load of the Southwest communities from the 1996 323 mm line to the 1956 273 mm line.

In the current configuration, the Power Station Class customer is being supplied by a dedicated pipeline and the Special Contract Class customer is being supplied by two dedicated pipelines. Due to this operation and configuration, Centra is able to identify the facilities that can be assigned to the Special Contract and Power Station Classes.



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	M.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	M.B.	K.M.	K.M.
5	2020-10	CLOSE T6-001, ADD FT 431, 433 & 280 REMOVE FT-138	M.B.	K.M.	K.M.
6	2022-05	REMOVE VALVES BDN T6-001, T6-002 & T6-003	M.B.	D.C.	D.C.
6	2022-05	ADD PIG LAUNCHER AT GS-124 & VALVE STN AT FOREST	M.B.	D.C.	D.C.

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please explain Centra's views on whether the cost allocation methodology should be based on the original configuration of assets or the current configuration of assets.

RESPONSE:

Centra considers that the current configuration of assets is the most appropriate basis to use to evaluate cost allocation methodologies. This view is consistent with the PUB findings in Order 164-16 that the allocation methodology should consider how an asset fits in the current system planning as well as its current use[1]. Both of these considerations are entirely dependent on the current configuration of the asset which reflects how the system has evolved to serve changing load and operating requirements in the most economic fashion.

In addition, developing a rate design that provides appropriate price signals requires a costing methodology that functionalizes and classifies assets on the basis of current usage and system conditions. Using a methodology that reflects original asset configuration and the factors impacting the original investment, when more recent and relevant information is available, provides an inferior pricing that may not fully reflect current system operations.

[1] PUB 164-16 page 27

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please explain Centra's views and rationale for whether cost allocation methodology should be based on normal operating conditions or emergency situations or a combination of both.

RESPONSE:

Centra's cost allocation study is designed to produce rates for an average customer under normal conditions. Since the revenue requirement, load and other inputs underlying the study represent typical operating conditions it is appropriate to consider system operations only under normal conditions when evaluating costing methodologies.

To the extent that the revenue requirement for the test year includes any incremental costs for facilities or activities that are related to emergency situations and justified entirely on that basis, it may be appropriate to consider usage during emergency situations for these specific items. The need to consider this alternate view of causality depends on the materiality of the costs, as well as the ability to clearly and discretely identify these incremental assets or activities. Even in cases where it is appropriate to consider use in emergency situations, it is also appropriate to consider any alternate uses for the assets under the typical operating conditions assumed for the test year when evaluating the allocation methodology.

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

Centra states:
Both the Special Contract and Power Station Classes use gas very differently than all other gas customers and their usage can vary significantly based on operating conditions, market conditions and the price of natural gas. Given that their unique usage characteristics makes it inherently difficult to forecast usage for both classes, a Direct Assignment of costs also has the benefit of providing greater rate stability to other customer classes. As additional investments are required on the specific pipelines being directly assigned to these classes, the capital costs of the pipelines will be allocated directly to these classes and will increase in future studies." **Application, page 32, lines 20 – 27**

QUESTION:

d) Without disclosing CSI, please identify, explain, and provide Centra's rationale for how upgrades to the transmission system driven by increases to the SC load since 1996 were treated, including at least on three occasions i) in the late 1990's, ii) early 2000's and iii) in connection to the more recent Brandon Primary GS upgrade. For example, were these transmission upgrade costs treated as system betterment costs and rolled into rates for all customers, paid for though customer contributions from the SC class, or some combination?

RESPONSE:

Please see the response to CAC/CENTRA I-11a.

Special Contract load growth for the past 25 years has been largely met through the available transmission capacity and system modifications (described in the response to

CAC/CENTRA I-11a), without the requirements of a customer contribution in aid of construction ("CIAC") from this customer. The cost of the transmission upgrade was rolled into the rate base and funded by all customers in their rates.

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Without disclosing CSI, please provide a discussion of how the direct assignment was accomplished within Centra's COS. In responding, please provide a qualitative discussion of the assumptions made, along with Centra's rationale, to isolate the transmission main costs directly assigned to the SC customer to arrive at the indicative revenue requirement (and rate base) for this class as per Figure 10, including i) the types of other transmission plant cost assignment, if any, ii) depreciation levels assumed iii) the level of offsetting amortization of customer contributions, if any, iv) how finance expense (debt and equity) was assigned v) the types of OM&A assumed vi) the assignment of corporate allocation vii) the assignment of taxes, viii) land and easement costs assignment and ix) general plant.

RESPONSE:

For the purposes of Centra's illustrative results in Appendix 4 Centra directly assigned the costs of the 6 inch and 12 inch Transmission mains that flow from the Brandon Primary Station to the MS-001 (yellow highlighted lines per the schematic provided below) that serves the Special Contract customer. In addition, Centra has directly assigned costs associated with the assets serving the Special Contract customer located within the Brandon Primary Station. The design of the Brandon Primary Station is such that assets within it can be delineated between those that serve the Special Contract customer, the Power Station and the rest of the Brandon area. The costs directly assigned to the Special Contract customer include a flow meter, meter isolation valves, pipe and fittings.

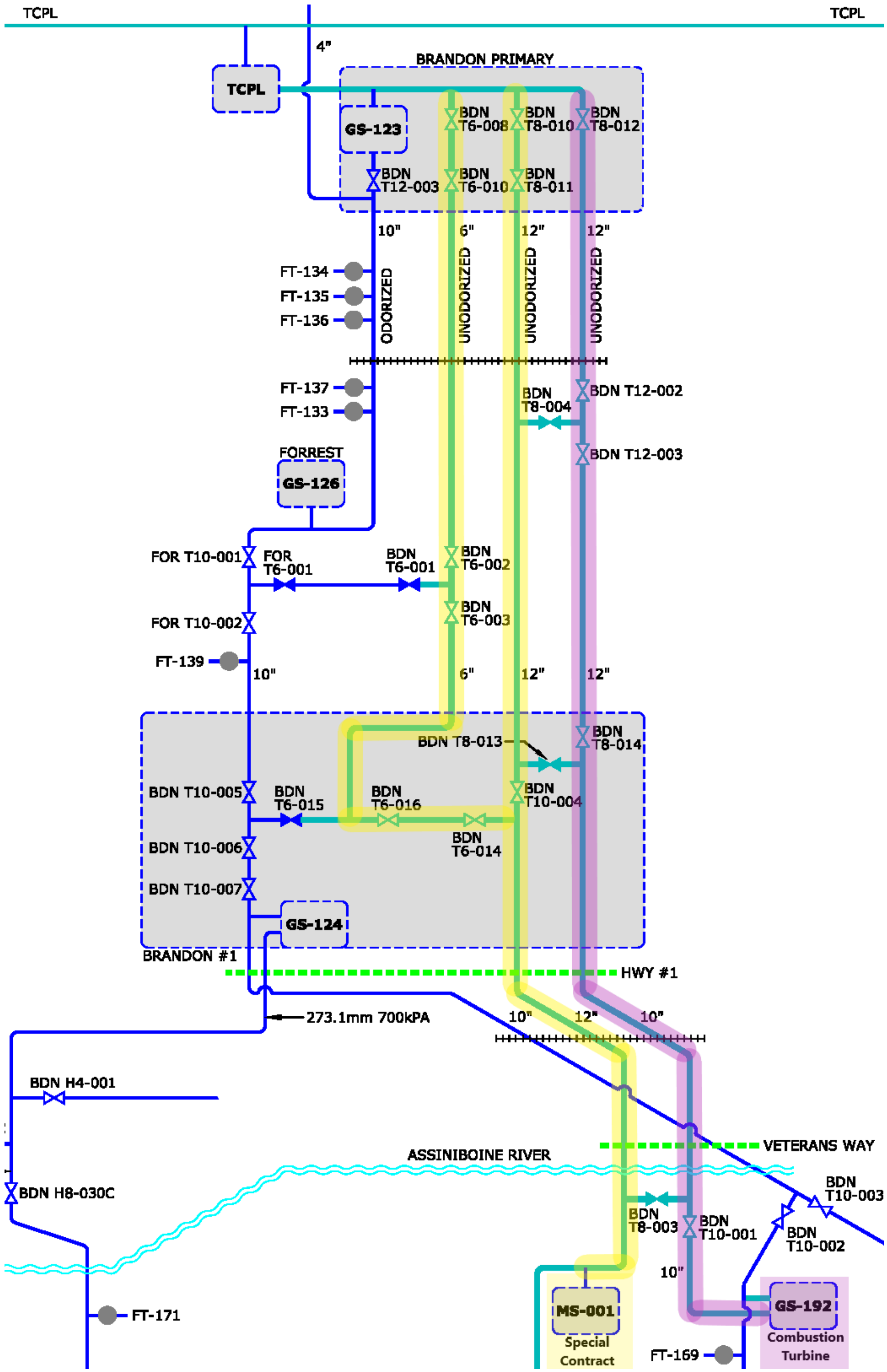
Consistent with its current practice Centra's proposed methodology directly assigns the costs of the dedicated Measuring and Regulating Station (MS-001).

Centra has discontinued the allocation of the amortization of CIAC to the Special Contract class as there are no customer contributions related to these specific transmission assets.

All other costs included in the indicative revenue requirement for the Special Contract Class were allocated as follows:

- Depreciation Expense is allocated in proportion to the corresponding plant accounts, consistent with the approved methodology.
- Finance Expense, Taxes, Corporate Allocation and Net Income continued to be allocated on the basis of Rate Base consistent with the current methodology.
- Land and easement costs related to transmission plant and distribution plant continue to be allocated based on the total transmission plant and distribution plant, respectively.

In addition, the Special Contract customer will continue to receive an allocation of Operating & Administrative ("O&A") expenses in the same manner as the current approved methodology. O&A costs allocated using the Peak and Average method in Centra's current methodology are allocated using the Peak Day method in the proposed methodology that underlying Figure 10 of the Application.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TCPL
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BRANDON PRIMARY
GS-123
BDN T6-008
BDN T8-010
BDN T8-012
BDN T12-003
BDN T6-010
BDN T8-011
10"
6"
12"
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FT-134
FT-135
FT-136
ODORIZED
UNODORIZED
UNODORIZED
UNODORIZED
FT-137
FT-133
BDN T8-004
BDN T12-002
BDN T12-003
FORREST
GS-126
FOR T10-001
FOR T6-001
BDN T6-001
BDN T6-002
BDN T6-003
FOR T10-002
FT-139
10"
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12"
12"
BDN T8-013
BDN T8-014
BDN T10-005
BDN T6-015
BDN T6-016
BDN T10-004
BDN T6-014
BDN T10-006
BDN T10-007
GS-124
BRANDON #1
HWY #1
273.1mm 700kPA
10"
12"
10"
BDN H4-001
VETERANS WAY
ASSINIBOINE RIVER
BDN H8-030C
BDN T10-003
BDN T8-003
BDN T10-001
BDN T10-002
10"
MS-001
Special Contract
GS-192
Combustion Turbine
FT-171
FT-169

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

QUESTION:

f) Similar to IR 11.5 above and without disclosing CSI, please provide a qualitative discussion of the assumptions made, along with Centra's rationale, to isolate the transmission main costs directly assigned to the PS customer to arrive at the indicative revenue requirement for this class as per Figure 10, as well as rate base including i) the types of other transmission plant cost assignment, if any, ii) depreciation levels assumed iii) the level of offsetting amortization of customer contributions, if any, iv) how finance expense (debt and equity) was assigned v) the types of OM&A assumed and vi) the assignment of corporate allocation vii) the assignment of taxes, viii) land and easement costs assignment and ix) general plant. In responding, please also discuss how the allocation of cost related to the Selkirk GS was arrived at including how the Brandon CT was isolated from the Selkirk GS in order to allocate costs of the broader system based on its individual load as forecast as part of the 2019/20 GRA.

RESPONSE:

For the purposes of Centra's illustrative results in Appendix 4, Centra directly assigned the costs of the 12 inch Transmission mains that flow from the Brandon Primary Station to GS-192 (purple highlighted line per the schematic below) that serves the Brandon Power Station to the Power Station class. In addition, Centra has directly assigned costs associated with the assets serving the Brandon Power Station located within the Brandon Primary Station. As discussed in CAC/CENTRA I-11e, the design of the Brandon Primary Station is such that assets within it can be delineated between those that serve the Special Contract customer, the Power Station and the rest of the Brandon area. The costs directly assigned to the Brandon CT include a flow meter, meter building, isolation valves, pipe and fittings.

Consistent with its current practice, Centra's proposed methodology directly assigns the costs of the dedicated Measuring and Regulating Station (GS-192).

Centra continues the allocation of the amortization of CIAC to the Power Station class as there are still customer contributions related to these specific transmission assets.

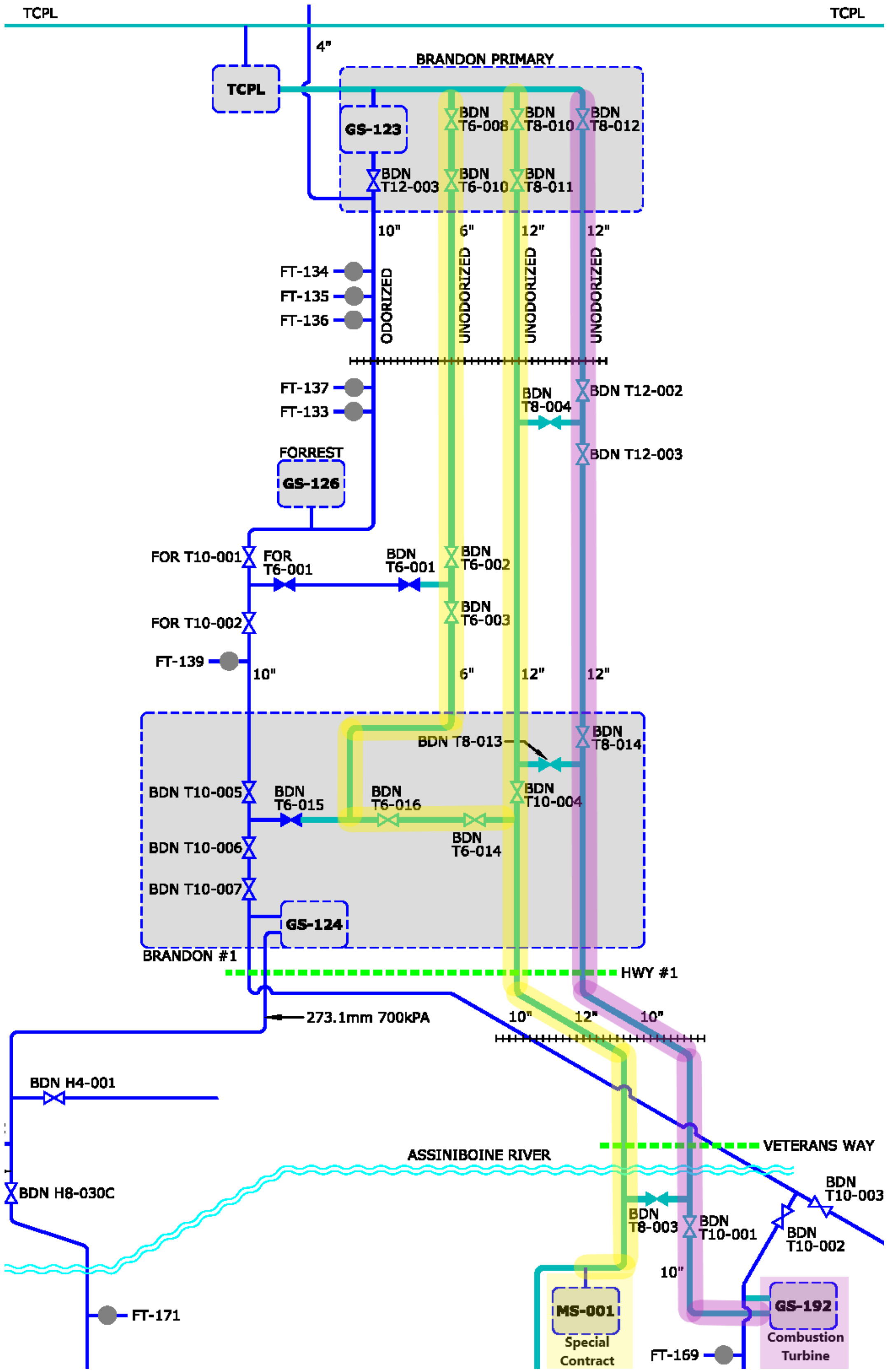
All other costs included in the indicative revenue requirement for the Special Contract Class were allocated as follows:

- Depreciation Expense is allocated in proportion to the corresponding plant accounts, consistent with the approved methodology.
- Finance Expense, Taxes, Corporate Allocation and Net Income continued to be allocated on the basis of Rate Base consistent with the current methodology.
- Land and easement costs related to transmission plant and distribution plant continue to be allocated based on the total transmission plant and distribution plant, respectively.
- Centra continues to allocate amortization related to CIAC to the Power Station class as there are still customer contributions related to these specific transmission assets.

In addition, the Special Contract customer will continue to receive an allocation of Operating & Administrative ("O&A") expenses in the same manner as the current approved methodology. O&A costs allocated using the Peak and Average method in Centra's current methodology are allocated using the Peak Day method in the proposed methodology that underlying Figure 10 of the Application.

As Centra notes in the COSMR submission the Selkirk Power Station is no longer part of the transmission grid and the assets associated with generating power were retired on March 31, 2021, and will be physically decommissioned once a decommissioning plan is established. For the purposes of consistency when developing the illustrative results, the load for the Power Stations Class has not been adjusted to reflect the reduced volumes resulting from the retirement of the Selkirk Power Station – i.e. the load remains the same as what was filed in the 2019/20 GRA. As a result, the illustrative Cost of Service Study assumes the Power Stations Class is receiving an allocation of the entire transmission system (less any assets being directly assigned) related to the forecast load of the Selkirk Power Station as well as the Direct Assignment related to the transmission assets serving the Brandon Power Station. In other words, the illustrative allocation to Power Station class consists of both, the direct allocation to the Brandon station and an allocation of the entire transmission system for the Selkirk station.

Given that the unique usage characteristics makes it inherently difficult to forecast usage for Power Stations, a Direct Assignment of costs will provide a stable allocation of costs for the Power Station class and consequently to the other customer classes.


TCPL
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BRANDON PRIMARY
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GS-123
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BDN T8-012
BDN T12-003
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BDN T8-011
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6"
12"
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FT-135
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ODORIZED
UNODORIZED
UNODORIZED
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BDN T12-003
FORREST
GS-126
FOR T10-001
FOR T6-001
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FOR T10-002
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10"
6"
12"
12"
BDN T8-013
BDN T8-014
BDN T10-005
BDN T6-015
BDN T6-016
BDN T10-004
BDN T6-014
BDN T10-006
BDN T10-007
GS-124
BRANDON #1
HWY #1
273.1mm 700kPA
10"
12"
10"
BDN H4-001
VETERANS WAY
ASSINIBOINE RIVER
BDN H8-030C
BDN T10-003
BDN T8-003
BDN T10-001
BDN T10-002
10"
MS-001
Special Contract
GS-192
Combustion Turbine
FT-171
FT-169

REFERENCE:

Section 4.1.2, page 32, lines 1-18, 20 – 27, Section 4.2, page 34, lines 2-7, Atrium Report, page 31

PREAMBLE TO IR (IF ANY):

QUESTION:

g) Please explain if the PUB was to approve the direct assignment of the costs associated with transmission mains to the SC, are other customers able to connect to that transmission main; and if so, how would the cost responsibility of the shared transmission be allocated between the new customers and SC?

RESPONSE:

The line serving the SC class is at capacity so it is not anticipated at this time that any other customers will be connected to that transmission main. Should the circumstances change in the future, Centra will review how the cost responsibility of any shared transmission will be allocated.

REFERENCE:

Section 4.2, page 34, lines 2-7

PREAMBLE TO IR (IF ANY):

Centra states:
"Centra acknowledges that the use of a minimum system or zero-intercept study to classify costs between Demand and Customer could produce results different than Centra's current split, which is based on the historic results of a diameter length study. While the current level of detail in its plant records is insufficient for Centra to undertake a zero-intercept study at this time; some work is currently underway that may provide sufficient granularity to perform the study in the future." **Application, page 34**

Atrium states:
"Atrium recommends revisiting Centra's basis for the Customer component of distribution mains using either a zero intercept or minimum system method. The current method used by Centra to determine the customer component has not been revisited in many years. Atrium understands that Centra is currently conducting a depreciation study, after which the related plant accounting data should be organized in such a manner that will facilitate the performance of a new study to determine the customer component of its distribution mains." **Atrium Report, page 31**

QUESTION:

a) Please describe the work that is underway and whether such work will be completed for purposes of the next GRA.

RESPONSE:

Please see the response to PUB/CENTRA I-18a-g.

REFERENCE:

Section 4.2, page 34, lines 2-7

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide Figure 10 of Centra Application, that reflects the use of an NCP allocator for purposes of allocating distribution demand-related costs along with a discussion of the derivation of the NCP.

RESPONSE:

For Centra the term non-coincident peak may refer to one of the following:

- The sum of the peak day of individual customers within the class which is equivalent to the billing demand units in each month; or
- The maximum daily class load in any given month.

Non-coincident demand units are only determined for customer classes that have a monthly demand charge as part of their rate design (High Volume Firm, Mainline, Power Station & Interruptible classes). Centra does not track or record the individual peaks for SGS and LGS customers on its system, as these values are not used for either cost allocation or billing purposes. As a result, Centra is not able to complete the requested analysis.

REFERENCE:

Section 4.2, page 34, lines 2-7

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide the approximate timeframe of the completion of Centra's depreciation study.

RESPONSE:

Centra is expecting to receive a draft report of the IFRS Average Service Life ("ASL") depreciation study from the consultant this summer (July-August time frame) at which time Centra will assess the results and impacts of the study on the financial statements. Following the review and assessment period with the consultant, a final report will be generated and reviewed with senior management for approval.

REFERENCE:

Section 4.1.1, page 30, lines 11-14, Section 4.3, page 35, lines 4-8, Atrium Report, page 24

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please clarify what is meant by the statement that Interruptibles use Centra's distribution system to receive Alternate Supply while being curtailed for upstream capacity factors given that Interruptibles load is reflected in Centra's distribution system planning and design and proposed to be treated as firm for downstream cost allocation purposes.

RESPONSE:

Centra does not contract for upstream transportation capacity to satisfy Interruptible customer demand. When Centra's transportation deliverability (i.e. upstream capacity) is required to meet firm customer demand, Interruptible customers are offered Alternate Supply Service (if supply is available in the market) such that they may continue to rely on natural gas for their operations. Centra's distribution system supports the delivery of Alternate Supply Service and as such, recovering downstream costs from Interruptible customers is appropriate as it ensures cost recovery from customers that use Centra's distribution system.

REFERENCE:

Section 4.1.1, page 30, lines 11-14, Section 4.3, page 35, lines 4-8, Atrium Report, page 24

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please explain whether Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group as noted by Atrium in its report, page 24.

RESPONSE:

Centra's upstream capacity resources cannot accommodate the cumulative design day peak demands of the interruptible customer group because Centra does not contract for services to meet peak Interruptible load. Please also see the response to PUB/CENTRA I-14.

REFERENCE:

Section 4.1.1, page 30, lines 11-14, Section 4.3, page 35, lines 4-8, Atrium Report, page 24

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide Centra's understanding, view, and rationale of Atrium's recommendation that winter season throughput be used to allocate Supplemental Supply as noted in Atrium's Report, page 24.

RESPONSE:

Atrium's recommendation that winter season throughput be used to allocate Supplemental Supply is consistent with Centra's current approach. Centra allocates variable transportation costs related to storage and Supplemental Supply using winter season throughput as these costs relate to serving customers' winter energy requirements.

REFERENCE:

Section 4.1.1, page 30, lines 11-14, Section 4.3, page 35, lines 4-8, Atrium Report, page 24

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please explain and provide the rationale of how non-gas costs are currently classified and allocated to the upstream functions commodity and capacity per Appendix 4, Schedule 10.1.2, including, for example, what non-gas costs vary based on throughput (volumes).

RESPONSE:

Non-gas costs allocated to upstream functions primarily include operating costs related to the following programs:

Customer Service & Corporate Relations
- Back / Middle Office Services
- Energy Supply, Planning & Support Programs
- Rates & Regulatory

Organizational Support
- Corporate Governance
- Corporate Infrastructure
- Corporate Services
- Departmental Support
- Operational Management

Organizational Support programs as well as Rates & Regulatory costs are functionalized to both upstream and downstream functions in proportion to how total O&A expenses are functionalized; and classified based on each function's proportional classification. This treatment does not suggest that the costs vary based on throughput but rather recognizes that these costs are incurred to support all operational areas of the enterprise.

Program costs related to Back / Middle Office Services, which includes costs associated with revenue and cost accounting for natural gas procurement, transportation, and storage, are functionalized in the same proportion as Gas Costs are functionalized (Production, Pipeline and Storage). Costs within each function are in turn classified as Energy and Demand in the same proportion that Gas Costs within each respective function are classified.

Energy, Supply, Planning & Support Programs are functionalized to Production, Pipeline, Storage and Transmission according to operating orders that are directly associated with each of the upstream functions. Functionalized costs are then classified as either Energy or Demand based on Gas Costs in the same manner as described above. This again does not suggest these costs vary with throughput or peak demand but reflect that these costs are incurred in support of costs that do vary on those basis (commodity, transportation, storage).

REFERENCE:

Section 4.1.1, page 30, lines 11-14, Section 4.3, page 35, lines 4-8, Atrium Report, page 24

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please explain and provide the rationale for the current cost allocation methodology associated with Delivered Service and whether Centra is proposing any methodology changes as part of its Application.

RESPONSE:

Delivered service is gas delivered directly to Centra at the Manitoba Delivery Area ("MDA') by a counterparty. Currently, Centra distinguishes two types of delivered services, Primary Gas Delivered Service ("PGDS") and Supplemental Gas Delivered Service ("SGDS"). [redacted] To derive an Empress-based Primary Gas commodity cost, Centra identifies the commodity and transportation costs separately for PGDS. PGDS imputed transportation costs are functionalized as Pipeline, classified as energy, and allocated based on Sales Service volumes. PGDS commodity costs are recovered through Primary Gas rates. 1a,1c

The separation of commodity and transportation was also applied to SGDS until November 2020. At that time, Centra determined that SGDS was most similar to [redacted] are simply treated as commodity purchases at a location (with no imputing of a transportation component), [redacted] can be treated the same way. This treatment is appropriate as Centra's [redacted] Accordingly, Centra no longer imputes a transportation cost to SGDS purchases, with SGDS costs now 1a,1c wholly recovered through Supplemental Gas rates. Prior to November 2020, SGDS imputed transportation costs were functionalized as Storage, classified as energy, and allocated based on winter volumes. SGDS commodity costs were recovered through Supplemental Gas rates.

Centra is not proposing any methodology changes as part of its Application with the exception of Delivered Service commodity costs being assigned as AECO supply or non-AECO supply (rather than Primary Gas or Supplemental Gas) and recovered through a single Gas Commodity rate and Commodity Cost Balancing Deferral account rate rider (as required) when Centra's revised gas rate structure (re-bundling) is implemented as of November 1, 2022.

REFERENCE:

Section 5.0, pages 37-40, Section 2.1, page 5, lines 10-11, Section 4.1.1, page 29, lines 24, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Further to PUB/Centra IR I – 9, please provide Centra's plan with respect to the timing of the filing of its next GRA.

RESPONSE:

On April 11, 2022, Manitoba Hydro and Centra filed a letter with the Public Utilities Board proposing a combined electric and gas General Rate Application to be filed in November 2022, and is awaiting a decision from the PUB.

REFERENCE:

Section 5.0, pages 37-40, Section 2.1, page 5, lines 10-11, Section 4.1.1, page 29, lines 24, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

b) In the event that a Cost of Gas Application is filed by Centra prior to its next GRA (i.e. the timing of its next GRA is delayed), please discuss how Centra intends to deal with the approved cost allocation changes flowing from this Application along with the zone of reasonableness and rate design in the context of a gas cost application.

RESPONSE:

Currently, Centra does not anticipate that a Cost of Gas Application would be filed in advance of its next GRA. However, even if that were to occur, Centra is of the view that the introduction of a zone of reasonableness and/or any rate design changes would most appropriately occur and be reviewed as part of a GRA as opposed to a Cost of Gas Application and accordingly, Centra would propose that those matters be deferred until the next GRA. It is anticipated, however, that approved cost allocation changes that impact the gas costs would be reflected in a Cost of Gas Application if it was filed in advance of the next Centra GRA.

REFERENCE:

Section 5.0, pages 37-40, Section 2.1, page 5, lines 10-11, Section 4.1.1, page 29, lines 24, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please confirm or otherwise explain, whether Figure 11 reflecting Centra's proposed interim rate treatment regarding the SC and PS classes has been applied assuming that costs and rates are based on and RCC equal to one or unity. If yes, please provide Centra's rationale its proposed treatment.

RESPONSE:

Not confirmed. Centra's interim solution is based on re-instating the non-gas portion of rates for the Special Contract to those in effect prior to the 2019/20 GRA.

REFERENCE:

Section 5.0, pages 37-40, Section 2.1, page 5, lines 10-11, Section 4.1.1, page 29, lines 24, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please confirm that in addition to the indicative impacts provided in Figure 10 of Centra's Application, further negative impacts are expected for the SGS Class once the cost allocation proposals are reflected in the allocation of PGVA's as well as the consolidation of gas commodity rates for Primary and Supplemental Gas.

RESPONSE:

Not confirmed. Centra intends to prepare the allocation of the PGVAs consistent with the cost allocation methodology in effect when the balances occurred. All PGVAs balances incurred prior the implementation of any changes to cost allocation will continue to be allocated using the current approved methodology. Once the cost allocation proposals are implemented and reflected in the base rates then the following allocation of PGVAs will reflect the proposed methodology. The SGS share of the Transportation PGVA will be larger under the proposed methodology, however the PGVA balance may be negative or positive in any given year and will be collected or refunded to customers as necessary. No material impacts are expected from the consolidation of Primary and Supplemental Gas into a single Gas Commodity rate as discussed in PUB Order 131/21.

REFERENCE:

Section 5.0, pages 37-40, Section 2.1, page 5, lines 10-11, Section 4.1.1, page 29, lines 24, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

e) As noted in Figure 10 of Centra's Application, please discuss what policy reflection, if any, was undertaken in Centra's final assessment prior to filing its cost allocation proposals which all negatively impact low volume users, including residential customers and low income customers considering i) the use of the PAVG methodology "has been both a reasonable and practical solution", ii) the "wide range of methodologies that are considered to reasonably reflect cost causation", and iii) the "departure from Centra's longstanding PUB approved methodology"

RESPONSE:

As stated at page 37 of the Application:

> "*The proposed recommendations by Atrium reflect their view that Cost of Service Studies should stand on their own objective merits and reflect only considerations of cost causation. This is consistent with the approach used for Manitoba Hydro's electric Cost of Service Study, which then considers fairness and equity at the rate design stage*[5]*. Centra supports using the same approach for its gas operations which allows for a more transparent assessment of such considerations than is possible when non cost-causal factors are embedded within the methodology.*
>
> *Centra's support of the recommendations made by Atrium as outlined herein is based upon how they comport with the way Centra plans and operates its system and not on the potential allocation of Revenue Requirements by class that would occur as a result of these recommendations."*