REFERENCE:

Application p. 34 of 40; Appendix 1 Atrium Report pp.11-12, 20, MFR 8 Attachment 2 pp.13-14 of 25

PREAMBLE TO IR (IF ANY):

In its report at page 11, Atrium states: “From a purely cost causation perspective, transmission and distribution main investments are simply not a function of throughput. Instead, they are a function of the cumulative peak day demand of those customers served by those transmission and distribution main investments. Based on today’s rate design structures, changes in throughput will affect the recovery of the utility’s investment in distribution mains but that is much different from concluding that there is a cost causation relationship between the investment and throughput. In fact, there is no such cost relationship.”

In its report at page 20, Atrium states: “First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Second, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system or to reach existing customers when a particular distribution pipeline segment needs to be replaced. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on peak period demands and the number of customers served by the LDC”

At MFR 8 (Centra’s response to the 2012 Christensen Associates’ COSS Review), pp. 13-14 of 25, Centra stated:

> “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.”

When considering whether to expand its system and lay distribution mains, Centra is subject to the PUB’s approved feasibility test (per Orders 109/94, 124/96, 89/97, and 123/98). The feasibility test compares the revenues from the expansion with the estimated construction, operation, maintenance, and financing costs. Considering the revenues from most customer classes are predominantly derived from the volumetric rate revenue paid by customers (especially for SGS and LGS customers), it can be argued that the volumetric energy consumption of customers is what causes the company to make the investment decision and to proceed with extension of mains. In this way, therefore, an energy-related classification of mains costs may be appropriate.

QUESTION:

a) Please explain whether Atrium is aware of any natural gas utilities in North America that currently make use of a Peak & Average method (or one similar to NARUC’s Average & Excess demand methods) to allocate Transmission or Distribution demand-related costs. If so, provide more information regarding the justification or rationale used in that jurisdiction for the continued utilization of this allocation method for the natural gas utility in question. How prevalent is this approach?

b) Please provide Atrium’s views on the idea that the revenues, predominantly from volumetric rates, are a driver for the utility to construct gas mains and thus volumetric consumption is a cost causal factor.

c) Does “Principles of Public Utility Rates” by Bonbright, Danielsen, and Kamerschen support or recommend the use of minimum system methods for classifying mains? What do Bonbright et. al. recommend for classifying distribution mains?

d) Please provide additional justification for Atrium's position that number of customers is an appropriate proxy for length of distribution main and therefore is a significant cost driver.
e) Once a utility has installed a distribution main, how do the number of additional customers connecting to that main affect the costs incurred by the utility with respect to the mains?
f) Please provide descriptions of any alternative methodologies for allocating the cost of mains that take into consideration that length of the main is a significant cost driver.

RESPONSE:

Atrium disagrees with the premise in the Request that "an energy-related classification of mains costs may be appropriate," for the reasons stated in the referenced excerpts from our report.

a) Atrium is aware of the following jurisdictions where the utility commission has authorized the use of the Peak & Average method (or one similar to the Average & Excess demand method).

- Alaska: Enstar Natural Gas Company, Docket U-16-066 (2017)
  Regulatory Commission of Alaska Order, "Cost Allocation and Rate Design" discussed on p. 99, decision on this issue pages 104-105.
- Illinois: Northern Illinois Gas, Docket D-18-1775 (2019), Illinois Commerce Commission Order, p.126.
- Michigan: Consumers Energy Company, Docket U-20322 (2019) Michigan Public Service Commission Order No.25394.
- N. Carolina: Carolina Power & Light Company, Docket No. E-2, SUB 537 (1988). North Carolina Utilities Commission approved Peak & Average, with Minimum System.
- Pennsylvania: Columbia Gas of Pennsylvania, Docket R-2020-3018835 (2021).
- Washington: Rulemaking Proceeding on Cost of Service Studies, Docket No. UG-17003 (2020), General Order R-599.
- West Virginia: Hope Gas, Inc., Case No. 20-0746-6-42T (2021), Public Service

Commission of West Virginia, note: transitioning from P&A (Note Atrium supported Design Day Peak with Customer Component):

> *"The Commission finds that a movement away from the 2008 methodology (Hope's Method 1 [P&A]) is appropriate. However, in the interest of moderation and to allow for future review of the effects of a shift in CCOSS methodology, we will not adopt Hope's alternative methodology (Method 2 [Design Day Peak & Customer Component]) totally at this time. Instead, we will use, as an initial allocation, an average of the two methods."*

b) The distribution system investment is a function of the cost to serve the peak demands of the customers and the distance involved in attaching the customers to the system. The fact that revenues are predominantly recovered through volumetric rates is not a "driver" of the costs to construct mains. The notion that volumetric usage is a cost causal factor merely conflates line extension policy considerations with cost causation for purposes of cost of service studies; that is, a certain amount of expected revenue from a new customer will help pay for the return on and of the capital investment and associated O&M expenses through the rates the customer pays.

c) In <u>Principles of Public Utility Rates</u>, Professor Bonbright notes that the use of a two-part rate structure is based on the assumption that one part of the total costs of a utility's business is a function of the output of or energy provided by the system, whereas another part is a function of plant capacity and hence of all costs related to this capacity. Professor Bonbright goes on to point out, however, that: "this two-fold distinction overlooks the fact that a <u>material part of the operation and capital costs of a utility business is more directly and closely related to the number of customers</u> than to energy consumption on the one hand or maximum demand on the other hand." (Emphasis added) Ref. James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, <u>Principles of Public Utility Rates</u>, 1988 Edition, at 401.

However, Professor Bonbright's text has been known to favor elements of opposite sides of an argument (or neither of them) at various points throughout his text:

"But if the hypothetical cost of a minimum-sized distribution is properly excluded from the demand-related costs for the reason just stated … while it is also denied a place among the customer costs … to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly un-allocable portion of total costs. … But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that 'the sum of the parts equals the whole.'… In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with FERC accounts." Ibid, at 492.

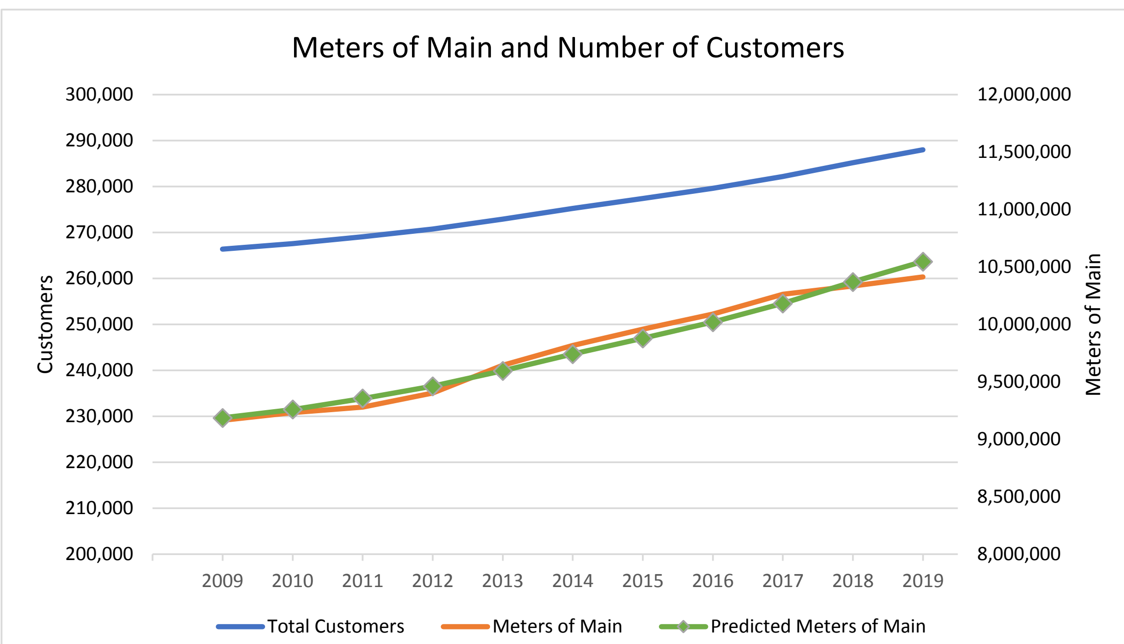
d) One can simply analyze the relationship between the total installed meters of distribution mains, and the number of customers as shown in graphical representation and table below. This schedule presents a linear regression analysis, which regresses Centra's number of customers served against the meters of mains installed by the Company over the 11-year period, 2009 through 2019. The regression analysis results indicate that the level of customers is strongly correlated to the meters of mains. Approximately 98% of the variation in Centra's meters of mains can be explained by the variation in the number of customers. Logically, as the number of customers served by Centra <u>increases</u>, the level of investment in distribution mains, as measured by installed meters, also <u>increases</u>.

Line	Year	Total Customers	Change	Meters of Main	Change	Predicted Meters of Main
1	2009	266,395		9,165,729		9,186,195
2	2010	267,558	0.4%	9,231,298	0.7%	9,259,416
3	2011	269,077	0.6%	9,280,960	0.5%	9,355,051
4	2012	270,777	0.6%	9,401,677	1.3%	9,462,082
5	2013	272,896	0.8%	9,644,222	2.6%	9,595,492
6	2014	275,230	0.9%	9,816,075	1.8%	9,742,438
7	2015	277,391	0.8%	9,957,471	1.4%	9,878,493
8	2016	279,645	0.8%	10,090,029	1.3%	10,020,403
9	2017	282,223	0.9%	10,262,784	1.7%	10,182,711
10	2018	285,188	1.1%	10,333,815	0.7%	10,369,385
11	2019	288,006	1.0%	10,414,409	0.8%	10,546,804

12 SUMMARY OUTPUT
13 Simple Regression of Miles of Mains and Number of Customers

Line	*Regression Statistics*	
15	Multiple R	0.987
16	R Square	0.975
17	Adjusted R Square	0.972
18	Standard Error	77,771
19	Observations	11

20		*Coefficients*	*Standard Error*	*t Stat*	*P-value*
21	Intercept	(7,585,789)	931,093.64	(8.15)	0.00002
22	X Variable 1	62.9591	3.3743	18.66	0.00000



e) Customers are continuously added to the distribution system under various installation conditions. Accordingly, the Minimum System analysis process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional cost of mains installed, there are contrasting situations where customers can be added only by extending the distribution system to the customers' "off-system" location.

f) See discussion of Centra's Diameter-Length Study in the R. J. Rudden Associates, Inc. Cost of Service and Rate Design Review Report (1996) on page 10 of 22 (Attachment 1 to this response).

Distribution Mains are functionalized to Distribution, and classified as demand-related and customer-related using Centra's existing diameter-mile study. RJRA recognizes that distribution mains exhibit both demand-related and customer-related costs because distribution mains serve two purposes: distribution mains have sufficient length to connect customers to the town border stations and distribution mains have sufficient diameter to meet the design day requirements of customers. There are three common methods for distinguishing the demand-related and customer-related components of distribution mains:

Minimum Grid Studies estimate the cost of connecting existing customers to the town border stations using the smallest diameter of pipe. Minimum grid studies are sometimes criticized for overstating the customer-component because even the minimum size pipe does provide some capacity.

Zero Intercept Studies estimate the cost of connecting existing customers to the town border stations using a hypothetical, zero diameter pipe. Zero intercept studies were developed in response to the criticism that minimum grid studies include some element of capacity. The zero diameter pipe would carry no capacity, and therefore would estimate the purely customer-related cost of distribution mains. Zero intercept studies are performed by regressing the cost per metre of distribution mains of varying diameters against the diameter (or some exponent of the diameter). The resulting intercept indicates the cost per foot of a zero diameter main.

Material/Labor Studies approximate the cost of connecting existing customers to the town border stations by recognizing that the cost of installing distribution main tends not to vary with the diameter of the main. Since only the material cost of the pipe varies with diameter, the material cost is considered to represent the capacity cost of the main, and the installation cost to represent the customer (capacity-invariant) cost of the main.

Centra's diameter-length study is a less common variation of these approaches, and is closely related to the minimum grid study. 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 (1 inch or less). The ratio of the minimum capacity to the total capacity is the customer-related percentage of distribution mains investment. In Centra's proposed 1995 Cost Study, the customer component was 33%.

REFERENCE:

Appendix 1 Atrium Report pp. 13 and 30

PREAMBLE TO IR (IF ANY):

At p. 13 of Atrium's report, Atrium states: "Further, the interruptible customers have not been curtailed for system reliability reasons for over twenty years. Therefore, Atrium recommends interruptible customers' demands should be included in the system peak day demand allocation, which would address concerns that interruptible customers would not contribute to the recovery of capacity costs under a CP method, resulting in shifting capacity costs to the firm customer classes."

However, at p. 30, Atrium's recommendation regarding the treatment of Interruptible customers is not included in Section 9.0 of Atrium's report.

QUESTION:

Please confirm whether the Interruptible customers' design day demands should also be included in the Coincident Peak Day Allocation Method recommended in Section 9.0 of Atrium's report (i.e. for Atrium's recommendations regarding the allocation of Transmission and Distribution assets, as well as for some upstream capacity resources).

RESPONSE:

Confirmed that Interruptibles should be included in the Coincident Peak Day allocation. However, not all Interruptible customers are typically heat sensitive. Therefore, an alternative to a design day peak or a composite of different measures may be considered for their contribution to the system peak.

REFERENCE:

Appendix 1 Atrium Report pp. 17-18; Appendix 1 Atrium Report Appendix A pp. A-15 and A-37; Application p. 33 of 40

PREAMBLE TO IR (IF ANY):

Appendix 1 Atrium Report, p. 17: “the Power Station Class should not receive an allocation of the broader transmission system capacity related to this power station’s demand requirements.”

Application, p. 33 (lines 1-3): “Centra notes that 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 and approved.”

QUESTION:

Considering the Selkirk generating station was served from shared transmission facilities, please confirm whether Atrium would still recommend that the Power Station class should not receive an allocation of the broader transmission system capacity if the Selkirk generating station was still operating.

RESPONSE:

If Selkirk were in service, then the Power Station class would receive an allocation of the shared transmission system based on the Selkirk station’s contribution to design day peak demand.

REFERENCE:

Appendix 1 Atrium Report p. 19

PREAMBLE TO IR (IF ANY):

"Based on Atrium's review of Centra's transmission and distribution pipeline systems, […], we find no apparent support for a departure from postage stamp ratemaking policy followed by Centra."

QUESTION:

Do the specific direct assignments proposed for the Special Contract and Power Station classes conflict with the principles of postage stamp rate- making? Please explain why or why not.

RESPONSE:

No. The term "direct assignment" means the allocation to a specific customer or class of customers based on exclusive identification of the customer or class with the particular plant or expense at issue. Usually costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation.

REFERENCE:

Appendix 1 Atrium Report p. 20

PREAMBLE TO IR (IF ANY):

"The two most commonly used methods for determining the customer cost component of distribution main facilities consist of the following: (1) the zero- intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment."

QUESTION:

Please explain the pros and cons of each of the zero-intercept or minimum-sized unit approaches for determining the customer cost component of distribution plant and which method of the two is viewed by Atrium as being i) most utilized by natural gas utilities in North America and ii) best suited for circumstances in Manitoba.

RESPONSE:

Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the utility's gas system against the actual size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the utility's distribution system, regardless of the customer's peak or annual gas consumption. The strength of the zero-intercept method is that it can produce a statistically significant result for the "zero inch" main; and therefore, needs no further adjustment for the load carrying capacity of that zero diameter main. The weakness inherent in the method is entirely related to the integrity of the underlying distribution pipeline data. The zero-intercept method requires vintage year pipeline data by size, material type, length, and installed cost from the plant accounting functional area of the utility. It has been Atrium's experience that many of our natural gas utility clients have not consistently maintained this level of detailed plant accounting records over time. This is often due to mergers and acquisitions among utilities whereby the consolidation of plant records results in losses of the original level of plant detail. Changes in accounting software products can often cause similar deterioration of the accounting records from the prior data storage system.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. This method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe diameter, the minimum-size method may include some capacity costs since any minimum size pipe considered will, in fact, be capable of actually delivering some level peak capacity. Therefore, to account for this capacity factor, an adjustment must be made to the minimum size pipe result to account for that size pipe's carrying capacity.

Atrium's data indicates that the minimum size method is: i) most utilized by natural gas utilities in North America by a ratio of three to one, and ii) from what we have learned about Centra's plant accounting records, is best suited for application to Centra's circumstances in Manitoba.

REFERENCE:

Appendix 1 Atrium Report p. 21

PREAMBLE TO IR (IF ANY):

"Atrium recommends that Centra update the services study from the current 2004 study with data up to the most currently available. Atrium further recommends that Centra index the vintage year installation cost data to current year costs in future service line studies. Because the service study is conducted using installed costs and not plant in service, this will provide a more equivalent comparison of cost of installation for developing the weighting factors."

QUESTION:

Please explain whether by "indexing" Atrium means to account for the impacts of inflation on the service line costs included in Centra's service line study.

RESPONSE:

Yes. Indexing accounts for the impacts of inflation.

REFERENCE:

Appendix 1 Atrium Report p. 22

PREAMBLE TO IR (IF ANY):

"The following are summary descriptions of the development of allocation methods by Centra for various O&M, Customer Service and Administrative expenses. Atrium found the analyses supporting the allocation methods to reflect a thorough representation of the underlying functions, responsibilities, and activities of the cost categories."

QUESTION:

For each of the O& M, Customer Service, and Administrative Expenses listed in Section 5.5 of Atrium's report (except for "DSM" for which additional information is requested in another information request), please identify:

a) Alternative allocation methods, based on Atrium's experience with other utilities and its own judgment;
b) The pros and cons of Centra's current allocation methods with respect to alternative allocation methods;
c) Atrium's rationale supporting Centra's continued use of each allocation method.

RESPONSE:

Response to parts a) through c):

In Atrium's collective experience in conducting cost of service studies over the course of several decades, and reviewing the studies performed by others, there are two general approaches to determining the basis upon which to allocate the referenced categories of costs. One approach is to choose a high-level allocator such as number of customers, annual throughput, or an internally generated allocator within the cost study that is typically a summation of different plant or O&M accounts. The other approach is to conduct a "Special Study." A Special Study is used when direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. In evaluating the costs charged to certain operating or administrative expense accounts such as those listed below, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed, which reflects a more accurate representation of the underlying cost causation and is the approach followed by Centra. Atrium considers this to be an industry best practice.

Distribution Maintenance – The portion of costs that are functionalized to Onsite are classified as customer-related. The costs are allocated to customer classes based on a two-year average weighting of number of dispatch calls.

An alternative high-level method often used to classify and allocate costs in this account is by an internally generated classifier and allocator based on the sum of the classification and allocation of all distribution plant accounts.

Unaccounted for Gas – Allocated to the customer classes using the percentage allocation established in Order 131/04.

See the response to PUB/ATRIUM I-8.

Dispatch – Allocated to the customer classes based on the two-year average of number of service orders calls.

An alternative high-level method often used to classify and allocate costs in this account is by number of customers.

Customer Inspections – The portion of costs that are functionalized to Onsite are classified as customer-related. The cost of burner tip service is allocated only to SGS customers. The costs for equipment inspections are allocated to all customer classes based on number of customers in each class.

Aside from Centra's appropriate direct assignment of the Equipment Problem Program costs, the classification and allocation method used by Centra is generally used to classify and allocate costs in this category in accordance with the type of equipment being inspected. For example, costs related to the inspection of meters on customer premises would be recorded in the Meters and House Regulators expense account (under the FERC Uniform System of Accounts). The costs in this account would then be classified and allocated according to the classification and allocation of the Meters plant account. Inspection of customer equipment behind the meter would be recorded in the Customer Installations expense account, classified as customer-related and allocated on number of customers.

Meter Repair – Allocated to the customer classes in proportion to Centra's Meter Repair study which estimates the meter repair costs for each customer class.

An alternative high-level method used is to classify and allocate costs related to the repair of meters would be recorded in the Meters and House Regulators expense account. The costs in this account would then be classified and allocated according to the classification and allocation of the Meters plant account.

Meter Reading – Allocated to the customer classes in proportion to monthly meter reading costs for each class as derived from the meter reading data from Manitoba Hydro Utility Services Ltd.

An alternative high-level method used to classify and allocate costs related to meter reading expense is on number of meters or customers.

Billing & Collections – Allocated to the customer classes based on the number of customers weighted by the effort required to produce bills and collect payments for each customer class.

An alternative high-level method used to classify and allocate costs related to Billing & Collections is on number of customers.

Customer Contact Center – Costs are directly assigned to the customer classes based on estimated call volumes by class.

An alternative high-level method used to classify and allocate costs related to Customer Contact Center is based on number of customers.

Customer & Public Relations – Allocated to the customer classes based on a composite allocation factor derived from customer numbers weighted for the specific expense categories.

An alternative high-level method used to classify and allocate costs related to Customer & Public Relations is based on number of customers.

Customer Safety – Allocated to the customer classes based on a composite allocation factor derived from customer numbers weighted for the specific expense categories of safety watching, odor related calls, customer education and safety.

An alternative high-level method used to classify and allocate costs related to Customer Safety is on number of customers.

REFERENCE:

Appendix 1 Atrium Report p. 22

PREAMBLE TO IR (IF ANY):

"Unaccounted for Gas – Allocated to the customer classes using the percentage allocation established in Order 131/04."

QUESTION:

a) Further explain and justify Atrium's reasoning for not recommending an update to Centra's Unaccounted For Gas study methodology, which was last reviewed by the Board in 2004.

b) Please discuss the possible benefits and practical expected outcomes associated with Centra refreshing its 2004 Unaccounted For Gas study.

RESPONSE:

a) Atrium did not engage in discussions with Centra specifically related to the allocation of Unaccounted for Gas (UFG) during the course of our review. The UFG study stated, "*It is expected that the pro-rata share of UFG would be relatively constant over time, assuming that the variables examined in this study remain constant and the forecast volumes for each customer class remain relatively unchanged. Should an individual customer class volume forecast change significantly in the future, or if there are significant changes to the factors that influence the overall level of UFG, the allocation percentages should be reviewed and adjusted if deemed appropriate.*"

b) Having since discussed the matter with Centra, Atrium recommends that the UFG study be updated to establish the current, overall system-wide level of UFG. Establishing a class-level allocation is unnecessary. UFG is a system-wide phenomenon, the cost of which should be recovered in a uniform system-wide fashion, similar to the weighted average commodity cost of gas. In addition, Atrium learned that a portion of the UFG costs are recovered in base rates and the remainder of the costs are recovered in Centra's gas cost recovery mechanism. Atrium recommends the recovery of UFG costs be consolidated in the gas cost recovery mechanism to provide better tracking of the fluctuating gas costs related to UFG and in the interest of administrative and auditing efficiency.

REFERENCE:

Appendix 1 Atrium Report p. 22; Order 164/16 p.85 of 116

PREAMBLE TO IR (IF ANY):

Atrium Report p. 22: “DSM – Allocated to the customer classes based on the forecasted participation by customer class.”

Order 164/16 (p. 85 of 116) regarding Manitoba Hydro’s electric Cost of Service Study: “The Board finds that DSM costs should be functionalized as 100% Generation. DSM should be classified with the other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion and unweighted energy for the Energy portion. The Board finds that DSM is a Generation resource: it avoids Generation costs, rather than the costs of Transmission and Distribution. […] DSM programs may appear similar to customer service programs such that the costs should be allocated or assigned to individual customer classes on a cost causation basis. The Board finds that, because DSM is a system resource, assigning DSM costs to individual classes is not warranted.”

QUESTION:

a) With respect to the allocation of demand-side management (“DSM”) costs, please explain how Centra should functionalize, classify, and allocate DSM costs if DSM costs were to be treated as a system resource, similar to the approved cost allocation method for the electric cost of service study.
b) Please explain the pros and cons of treating DSM costs as a system resource in the COSS compared to Centra’s proposed allocation based on class participation.

RESPONSE:

a) Based on the premise provided to the request, whereby the DSM costs are to be treated as a system resource, Centra should functionalize, classify, and allocate DSM costs in accordance with the corresponding specific avoided system supply resource costs that DSM programs are targeted to alleviate.

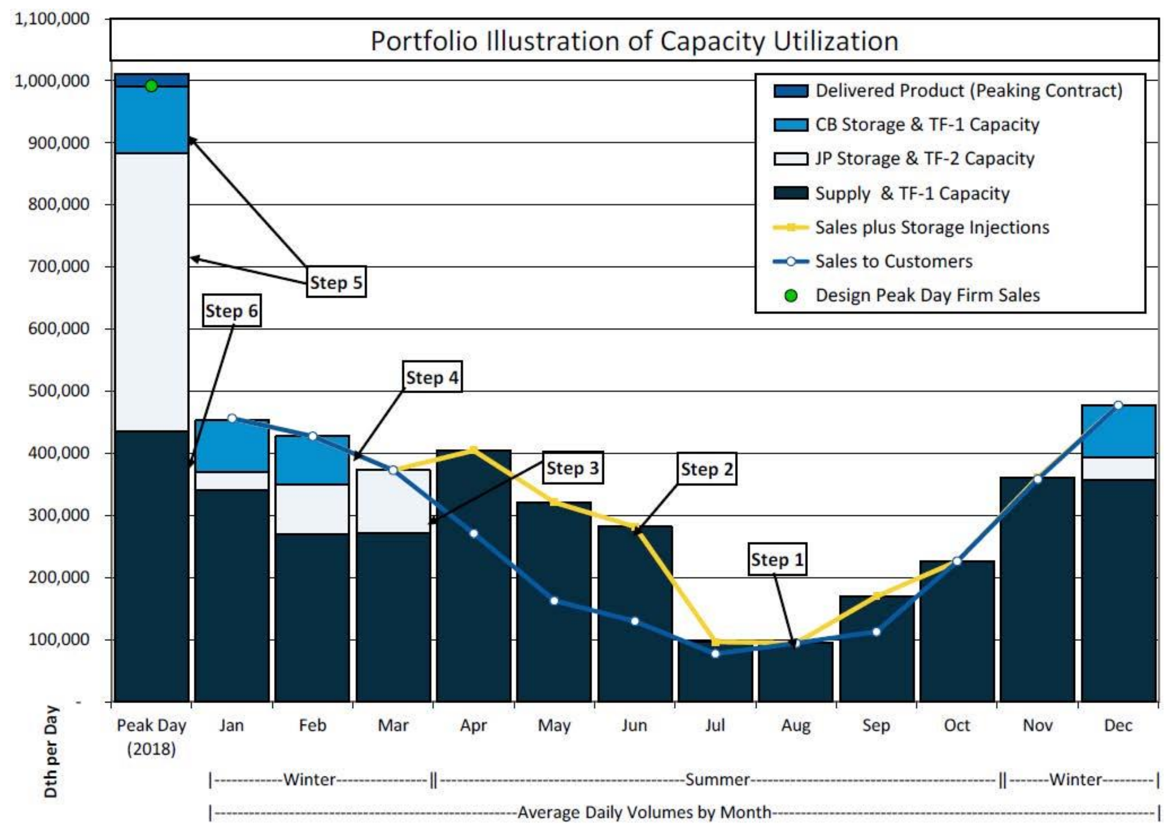
b) Under the assumption that there is an evidentiary basis that supports the finding of the Board that DSM is a system resource, there would presumably be some consistency between the methods for recovery of the DSM costs between electric and gas customers in Manitoba. However, the program bundles and the corresponding customer segments identified in the Efficiency Manitoba 2020/23 Efficiency Plan suggest that the natural gas DSM programs are targeted at those specific consumer markets and therefore the associated costs can be identified for direct assignment to the appropriate customer classes, which is consistent with utility cost of service principles. See the response to PUB/ATRIUM I-4.

REFERENCE:

Appendix 1 Atrium Report pp. 23-25

PREAMBLE TO IR (IF ANY):

"Atrium recommends that Centra conduct a seasonal resource stack- based analysis of each pipeline and storage capacity resource's contribution to the seasonal and peak day demands of its customers. The analysis should include modeling the use of pipeline capacity for serving the seasonal customer demands vis-a-vis storage injections as well as peak day."



QUESTION:

a) Further explain the steps involved in conducting a seasonal resource stack- based analysis of each pipeline and storage capacity resource as well as the incremental benefits that this analysis would provide to Centra over Centra's existing methodology.
b) Please explain what the output of the seasonal resource stack-based analysis yields in terms of allocators. Does the output include demand and energy allocators? Only demand allocators?
c) For Figure 2 of Atrium's report, please clarify how the utilization for each of the months shown relate to the peak day column on the left side of Figure 2.
d) Please explain why the seasonal resource stack-based analysis proposed is preferred by Atrium for the Manitoba circumstance over the alternative "winter season demand in excess of summer season demand".
e) Please explain Atrium's position regarding the treatment of Centra's Interruptible Class with respect to the proposed seasonal resource stack- based analysis.

RESPONSE:

Please note: The above Portfolio Illustration of Capacity Utilization as well as the steps described below does not and is not intended to reflect Centra's actual customer demand or supply-related capacity resources and is provided for illustrative purposes only.

a) Given Centra's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, that drives Centra to plan for and use upstream pipeline and storage capacity resources. Centra seeks the least-cost mix of available pipeline and storage capacity resources that can meet its design-day peak standard.

   The process for determining the need for pipeline capacity can be summarized in the process described below and illustrated in the portfolio illustration above. The steps reflect a logical progression in identifying why and when capacity is needed, and thus give guidance as to how to allocate the related costs. One must first consider the average summer demand. This must be served by flowing gas supply using year-round pipeline capacity because, other than for load balancing, storage and peaking resources are not available in the summer. Since this capacity is only available on a year-round basis and will be used to serve winter sales volumes as well, it is reasonable to allocate the cost of this capacity to annual volumes (Step 1).

In order to have sufficient volumes in storage to serve the winter sales volumes, storage injections must be made using flowing gas and year-round pipeline capacity. Because this capacity is needed specifically to fill storage, which is in turn used to serve winter sales volumes, it is reasonable to allocate the costs of this capacity to winter volumes (Step 2). This capacity is also available to flow additional gas to serve winter volumes after the summer injection period. Before determining the need for additional pipeline capacity to serve winter demand, the LDC must consider the average availability of storage withdrawals that use seasonal transportation capacity and thus do not require the use of year-round pipeline capacity. The seasonal transportation capacity utilized by storage withdrawals would reasonably be allocated partially to winter volumes, design peak volumes and of course, system load balancing (Step 3).

Winter average daily volumes are met with the capacity acquired in Steps 1, 2 and 3, thus leaving the remaining average winter demand to be fulfilled with additional year-round pipeline capacity. It is reasonable to allocate the costs of this capacity to winter volumes (Step 4).

The LDC must consider its design peak requirement and the deliverability of all of its storage and peaking resources that have not already been considered in use on the average winter day. It is therefore reasonable that the costs of the various available resources that provide this incremental deliverability should be allocated based on their use to serve the design peak requirements of the system (Step 5).

If the design peak demand is not yet met, and no additional gas storage or peaking resources are available in a cost-effective manner, the LDC thus must use additional year-round pipeline capacity. Because this last increment of pipeline capacity is required only to serve the design peak day requirements of the customer demand, it is reasonable to allocate the cost of this capacity based on the contribution of various customer classes to design peak day demand (Step 6). This illustration demonstrates the systematic approach to allocating the various components of an LDC's upstream pipeline and storage capacity resources to meet the demand requirements of its firm customers throughout the year.

Atrium recommends that Centra conduct a seasonal resource stack-based analysis of each pipeline and storage capacity resource's contribution to the seasonal and peak day demands of its customers. The analysis should include modeling the use of pipeline capacity for serving the seasonal customer demands vis-a-vis storage injections as well as peak day.

b) The contract based fixed capacity costs of the resources would be demand-related costs; therefore, yielding demand allocators.

c) See steps 5 and 6 in part a) above.

d) See the response to part a).

e) The treatment of Centra's Interruptible Class for purposes of this analysis would be determined by Centra's evaluation of the capacity resources that serve the Interruptible demands. See the quotation from the Atrium Report in the Preamble to PUB/ATRIUM 1-11, below.

> *"In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand. Winter season throughput would be an alternative allocation method for Supplemental Supply. An alternative allocation method for year-round pipeline capacity should be peak day demand, at the design day level. For interruptible customers, Centra should consider the use of a 100% load factor contribution to the peak day allocator. This will prevent these customers from escaping some peak day responsibility; that is, if Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group."*

REFERENCE:

Appendix 1 Atrium Report pp. 24-25 and B-1

PREAMBLE TO IR (IF ANY):

"In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand. Winter season throughput would be an alternative allocation method for Supplemental Supply. An alternative allocation method for year-round pipeline capacity should be peak day demand, at the design day level. For interruptible customers, Centra should consider the use of a 100% load factor contribution to the peak day allocator. This will prevent these customers from escaping some peak day responsibility; that is, if Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group."

QUESTION:

a) Please explain why Winter Season Demand in Excess of Summer Season Demand is a more appropriate allocator than Coincident Peak or Peak & Average for the storage and related pipeline capacity costs.
b) Please explain why winter season demand in excess of summer season demand is not a more appropriate allocator than Coincident Peak or Peak & Average for the year-round pipeline capacity costs.
c) Please explain how the summer season demand should be defined for the Manitoba situation and whether it should include the April and October demands (i.e. generally deemed shoulder months for gas consumption in Manitoba).
d) Given that Centra's need to serve customers in the shoulder months (April, May, and October) drives the supply, storage, and transportation requirements of its portfolio of contracted assets, please explain how the Winter Season Demand in Excess of Summer Demand captures the contributions of each class toward the costs incurred to meet these requirements. Does the seasonal resource stack-based analysis better address the allocation of costs incurred to serve these shoulder month periods?

RESPONSE:

a) From a purely cost causation perspective, the contracted level of storage and related pipeline transportation capacity serve the cumulative design day peak and winter season demands of those customers by those winter season upstream resources, which are in excess of the level of year-round pipeline capacity. Changes in throughput will affect the timing of recovery of the utility's upstream capacity costs but that is much different from concluding that there is a cost causation relationship between the capacity costs and throughput. In fact, there is no such cost relationship.

b) The year-round pipeline capacity costs are incurred to serve the coincident peak capacity needs of Centra's customers, a critical role in peak day resource stack. The response to PUB/ATRIUM I-10a discusses the role that year-round pipeline capacity may play in serving the coincident peak capacity needs of an LDC's customers, which is also illustrated in the peak day column on the left side of the accompanying Figure 2.

c) Centra should determine the range of months that defines the summer season based on its own evaluation of the shoulder months, whereby the incremental storage deliverability and related pipeline capacity are required to serve the incremental seasonal demand and are contractually available.

d) See the response to PUB/ATRIUM I-10a.

REFERENCE:

Appendix 1 Atrium Report p. 26 (section 7.1), Application pp. 29 and 36 of 40

PREAMBLE TO IR (IF ANY):

Appendix 1 Atrium Report, p. 26: "Atrium believes that non-cost causation considerations should be addressed outside of the cost of service study process, reflecting revenue allocation and rate design principles such as non- discrimination (e.g., fairness and equity), which may impact judgements regarding a sufficient zone of reasonableness. […] In Atrium's experience, many utilities and regulatory commissions recognize a zone of reasonableness in setting class revenue responsibility, with the use of parity ratios as a guide, and we recommend that it be considered in this instance whereby a full cost of service methodological review has been undertaken."

Application p. 29 (lines 21-29): "The Peak and Average methodology has been used since 1996 and recognizes the utilization of the system as an explicit factor to be included in the determination of cost responsibility. Centra believes that its historic use of the Peak and Average allocator has been both a reasonable and a practical solution to incorporating fairness considerations in the development of rates. While the use of a Coincident Peak allocator would be a departure from Centra's long-standing PUB approved methodology, it more accurately reflects the cost causation principle."

Application p. 36 (lines 7-11): "As a ZOR recognizes the range of judgment that applies when conducting Cost of Service studies and would facilitate considerations of fairness and equity as well as rate stability and gradualism at the rate design stage, Centra is supportive of the recommendation put forward by Atrium to establish a ZOR and intends to bring forward its recommendation as part of its next GRA."

QUESTION:

Further explain the link between the proposed implementation of the Coincident Peak Day allocator and the possible re-introduction of a Zone of Reasonableness at the rate design stage (e.g. at Centra's next General Rate Application). Specifically, does the need for a Zone of Reasonableness now arise as the proposed implementation of a Coincident Peak Day allocator removes the fairness and equity considerations currently embodied in the current Peak and Average allocator?

RESPONSE:

No, Fairness requires no undue subsidization either between customers within the same class or across different classes of customers. This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized to properly distribute the total cost of service to and within customer classes.

This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

REFERENCE:

Application p. 34 of 40; PUB MFR 7 Attachment p. 30 of 102

PREAMBLE TO IR (IF ANY):

Application p. 34 (lines 5-10): "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. As the current 67%/33% split between Demand and Customer is within industry standards, Centra is not proposing or committing to undertake any additional studies on this matter at this time and awaits feedback from stakeholders as part of this proceeding."

MFR 7 Attachment, p. 30 of 102 (lines 21-27): "Initially, it was RJRA's intention to recommend that Centra switch to the zero intercept methodology. However, when RJRA attempted to perform a zero-intercept study for Centra, we recognized that Centra's available data on distribution mains investment was not perfectly suitable for such an analysis. Since Centra's present methodology results in a 33% customer component, which is quite reasonable when compared to other zero intercept studies performed by RJRA, we decided to accept the diameter-length results for the classification of distribution mains."

QUESTION:

Please provide Atrium's perspective regarding the reasonableness of Centra's existing 67%/33% split between Demand and Customer for distribution mains compared to other North American natural gas utilities

RESPONSE:

Atrium finds that Centra's current 67%/33% split between Demand and Customer classifications for distribution mains to be reasonable based on our experience with zero-intercept studies performed for our clients. As to the recent work by Centra in connection with a depreciation study, we find that the granularity of vintage mains data from that study recently reviewed by us is inadequate for the purpose of conducting a statistically sound zero-intercept study. Alternatively, we recommend Centra pursue a most-commonly-installed, minimum-size unit of mains plant ("minimum system") study to determine a new Demand/Customer split for distribution mains.

REFERENCE:

Application pp. 4 and 36 of 40; Appendix 4 p. 4 of 16; MFR 7-Attachment 2 p. 14 of 102

PREAMBLE TO IR (IF ANY):

“Customer classes currently served by Centra include: Small General Service Class (“SGS”) – Residential (“SGS-R”) and small commercial (“SGS-C”) customers with an annual consumption less than 680,000 m3 […]”

Centra’s Cost of Service Study allocates costs to the SGS-R and SGS-C sub- classes but the cost allocation results for the two sub-classes are totaled together to inform the existing Small General Service rates.

MFR 7-Attachment 2 (p. 14 of 102, lines 15-23): “Centra weighed these difficulties against the potential benefits of having a separate Residential rate. The cost study indicates that residential customers are paying cost-based rates today. Based on the cost study, there is no reason to believe that a separate rate would offer any benefits to residential customers. Furthermore, the distinctions between the two groups do not appear to be great. Since the practical effects of a separate Residential rate would be to create artificial distinctions, without any significant change in rate levels, Centra has determined to reject RJRA's recommendation to create a separate Residential rate at this time. However, the residential customers will remain separated in the Cost of Service study so that the situation can be monitored in the future.”

QUESTION:

a) Please confirm whether Atrium considered the customer class definitions in its evaluation of Centra’s cost of service study.
b) Please explain Atrium’s views regarding the pros and cons associated with the implementation of separate customer classes and rates for the SGS-R and SGS-C sub-classes, considering they are already segregated in Centra’s cost of service studies.

RESPONSE:

a) Atrium did not consider nor question the structure of Centra's customer classes.

b) From an intra-class cross-subsidization perspective, the implementation of separate rates for the SGS-R and SGS-C subclasses could be beneficial for both subclasses, provided the respective load characteristics of the sub-classes, associated level of demand and customer classified costs, and the corresponding cost of service study results supported such a distinction. There would likely be some additional administrative costs associated with the separation of the sub-classes for rate design and billing system implementation purposes.