REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

a) Please provide a narrative description of all Centra Gas facilities (transmission pipelines and all facilities downstream of the transmission pipelines) used to provide service to the Koch Fertilizer plant in Brandon, Manitoba.
b) Are the NPS 6 diameter pipeline and the NPS 12 diameter pipeline that serve the Koch Fertilizer plant, as shown in the map attached to the response to KOCH/CENTRA I-1f, interconnected with any other Centra Gas transmission pipelines? If yes, please provide an updated map diagram with updated pressures and capacities that shows each interconnection (pipe size, capacity, and pressure) in detail.
c) Do the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serve any other customers besides the Koch Fertilizer plant? If yes, how many other customers are served by these pipelines?
d) Please describe how the Koch Fertilizer plant would be provided with gas supply if both the NPS 6 diameter and NPS 12 diameter pipelines serving the plant are out of service.

RESPONSE:

a) Centra provides natural gas service to the Koch Fertilizer plant in Brandon, the Manitoba Hydro Brandon Combustion Turbines, and approximately 13,000 customers through the Brandon pipeline system. This is an integrated system that consists of four transmission pressure pipelines that supply customers in the Brandon and southwest Manitoba area. The system has grown significantly since the installation of a single transmission pressure pipeline in 1955. System and operational modifications have been made to suit the requirements of the customers on the system. A single connection to the TransCanada Pipeline ("TCPL") at the Centra Gas Primary GS-123 is the supply for all pipelines and customers. In addition to the shared connection to TCPL and associated facilities, isolation and line access valves, and pipeline pig launchers are the main components at GS-123 associated with service to Koch. With reference to the map provided in the response to KOCH/Centra I-1 f), the pipelines supplying Koch include an NPS 12 pipeline from GS-123 to GS-125/GS-168 with a branch to MS-001 and a NPS 6 pipeline from GS-123 to GS-124. Meter station MS-001 is located at the Koch Fertilizer plant and contains two parallel customer meters. As mentioned, the system operation has changed over time to suit customer requirements. The NPS 12 pipeline currently supplying Koch was originally installed to supply Koch and the southwest Manitoba communities.

b) Please see the Brandon Gas Pipeline Schematic supplied at page 9 of the attachment to the response to IGU/Centra I-18. Three interconnects are provided from the Koch NPS 12 pipeline to the NPS 12/10 Brandon Combustion Turbine Pipeline (valves BDN T8-004, BDN T8-013 and BDN T8-003). There are two interconnects between the Koch NPS 6 pipeline and the Brandon NPS 10 pipeline (valves BDN T6-001 and BDN T6-015). The Koch NPS 6 connects to the Koch NPS 12 by BDN T6-014. The NPS 12/10 Brandon Combustion Turbine Pipeline operates at TCPL line pressures (no pressure regulation) and supplies unodourized gas. The Brandon NPS 10 pipeline supplies odourized gas and is pressure regulated to 435 psig. The maximum operating pressure of this pipeline is 600 psig. The design load of the Brandon Combustion Turbine Pipeline is [redacted] 1d
while the winter system design load for the Brandon Pipeline is [redacted]. Customer pressure requirements for Koch, the Brandon Combustion Turbines and the general customers in Brandon and area vary significantly and will greatly affect the pipeline capacity.

c) In normal system operation, the NPS 6 and NPS 12 pipeline do not supply any other customers.

d) With reference to the Brandon Gas Pipeline Schematic supplied at page 9 of the attachment to the response to IGU/Centra I-18, if the NPS 6 and NPS 12 pipelines can be isolated at GS-124 (north of Highway #1) with valves BDN T10-04 and BDN T6-014, valve BDN T8-003 can be opened to provide access to the NPS 12/10 Brandon Combustion Turbine Pipeline. The availability of this pipeline to supply Koch would be based on the status of operation of the Brandon Combustion Turbines. With the single pipeline, there may be a reduced supply available to Koch.

If the NPS 12 pipeline segment between GS-124 and GS-125 supplying MS-001 cannot be used, it will not be possible to supply Koch.

REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

e) Please provide Centra Gas's installed cost of the NPS 6 diameter pipeline and the installed cost of the NPS 12 diameter pipeline that serve the Koch Fertilizer plant.
f) Please provide Centra Gas's installed cost of all facilities, excluding the NPS 6 diameter pipeline and the NPS 12 diameter pipeline, which serve the Koch Fertilizer plant.
g) Please provide the gross plant amount, the accumulated depreciation amount, and the rate base amount for the NPS 6 diameter and NPS 12 diameter pipelines serving the Koch Fertilizer plant that are included in Centra Gas's total cost of service in this rate application.
h) Please provide the gross plant amount, the accumulated depreciation amount, and the rate base amount for all facilities, excluding the NPS 6 diameter pipeline and the NPS 12 diameter pipeline, serving the Koch Fertilizer plant that are included in Centra Gas's total cost of service in this rate application.
i) Please identify the respective current net book value (original cost – depreciation) for the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant.
j) Please provide the respective installation date for both the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant.

RESPONSE:

e) The installed cost of the NPS 6 diameter pipeline that serves the Koch fertilizer plant is $476K. The installed cost of the NPS 12 diameter pipeline that runs directly from the Brandon Gate Station #123 to the Koch fertilizer plant is $3,262K.

   When identifying the plant assets that "serve" the Koch Fertilizer plant, it is important to recognize that gas pipeline infrastructure systems, like the one serving the City of Brandon, are highly interconnected systems consisting of plant assets that are not considered to function independently of each other. Such systems are managed with the understanding that changes to one aspect of the system will typically impact other aspects of the system with respect to performance or redundancy considerations. As such, Centra has identified some of the other significant pipelines in the Brandon region that indirectly support the Koch plant. Those pipelines include an NPS 12 diameter pipeline with a cost of $5,460K that connects the Brandon primary gate station to the line serving the Brandon Generating Station and which also acts as a redundancy option for the Koch Fertilizer plant should the need arise. This NPS 12 diameter line attaches to an NPS 10 diameter pipeline with a cost of $1,092K that connects directly to the Brandon Generating Station.

f) Centra's installed cost of facilities in the Brandon region that support the Koch fertilizer plant, excluding the NPS 6 and NPS 12 diameter pipelines, includes the following:

- Distribution Meters: $60K
- Distribution Stations and Structures (Gate Station #123, Meter Service -001 and Gate Station #192): $1,593K
- Transmission Land: $63K
- Transmission Land Rights: $28K

In addition to the facilities identified above, there is an estimated $3.9 million project currently underway to re-build Brandon's primary gate station that connects to the TCPL mains and supplies all downstream customers including the Koch Fertilizer plant. The planned in-service date for this project is August 2019 and it is estimated that approximately $600K of this work is associated with the supply to the Koch plant.

g) Please see the table below for the estimated March 31, 2020 gross plant amount, accumulated depreciation amount, and rate base amount (i.e. Net Book Value) for the NPS 6 and NPS 12 diameter pipelines serving the Koch Fertilizer plant as well as the other significant pipelines identified in the response to part (e) above:

(in $ thousands)

Plant Item	Plant Cost	Accumulated Depreciation	Net Book Value (Rate Base)
NPS 6 diameter pipeline	$476	$412	$64
NPS 12 diameter pipeline	$3 262	$1 446	$1 816
Other Pipelines:			
NPS 10 diameter pipeline (connects directly to the Brandon Generating Station)	$1 092	$308	$784
NPS 12 diameter pipeline (connects the Brandon primary Gate Station to the Brandon Generating Station)	$5 460	$1 104	$4 356

h) Please see the table below for the estimated March 31, 2020 gross plant amount, the accumulated depreciation amount, and the rate base (i.e. Net Book Value) amount for the Brandon region facilities, excluding the NPS 6 and the NPS 12 diameter pipelines, supporting the Koch Fertilizer plant:

(in $ thousands)

Plant Item	Plant Cost	Accumulated Depreciation	Net Book Value (Rate Base)
Distribution Meters	$60	$53	$7
Distribution Stations and Structures*	$1 593	$945	$648
Transmission Land	$63	$0	$63
Transmission Land Rights	$28	$5	$23

*Excludes the Brandon primary gate Station re-build project for $3.9 million as this project is not scheduled to be fully in-service until August 2019.

i) Please see the response to part (g) above.

j) The respective installation dates for the NPS 6 and NPS 12 diameter pipelines serving the Koch Fertilizer plant are as follows:

- NPS 6 diameter pipeline: 1973
- NPS 12 diameter pipeline (Brandon Gate Station #123 to Koch plant): 1996

a) REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

k) For the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant, please identify the O&M expense in $ related to these pipelines included in Centra Gas's rate application test year.

RESPONSE:

As noted in the response to IGU/CENTRA I-8h, the costs to maintain pipelines are not specifically tracked by each section of pipe. Costs for general maintenance cannot be distinguished from the rest of the pipeline system, including steel valve maintenance, cathodic protection, buried plan locate services and Click Before You Dig/Safety Watch. Additionally, there are administrative costs associated with Pipeline Integrity and Safety & Loss Management Systems.

REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

l) For the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant, please identify the property tax in $ related to these pipelines included in Centra Gas's rate application test year.

RESPONSE:

The estimated taxes associated with these facilities are approximately $50,000 for 2019/20.

REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

m) Since the last rate case, please identify all improvements made to facilities, including the NPS 6 diameter pipeline and the NPS 12 diameter pipeline, serving the Koch Fertilizer plant and provide their respective installed costs.

RESPONSE:

Since the 2013/14 General Rate Application, one physical improvement was made to the facilities serving the Koch Fertilizer plant. This improvement included erosion protection for the NPS 12 diameter pipeline at the Assiniboine River crossing in 2016/17. The project cost was $150,000.

In addition, as noted in the response to IGU/CENTRA I-8h, there is a major rebuild required of the Centra primary station that connects to the TCPL mains and supplies all downstream customers including Koch. The planned in-service date of this work is August 2019. The portion of the work that is associated with the supply to Koch is estimated to be $600,000.

REFERENCE:

Centra Gas's Response to KOCH/CENTRA I-1a-c

QUESTION:

n) Please identify the revenue requirement for the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant included in the rates approved in Centra Gas's last rate case.

o) Please identify the revenue requirement for the NPS 6 diameter pipeline and the NPS 12 diameter pipeline serving the Koch Fertilizer plant included in the rates proposed for this rate case.

RESPONSE:

n) and o)

Centra is unable to isolate and provide a specific revenue requirement for the NSP 6 & 12 diameter pipelines. While costs such as depreciation expense may be estimated and may be directly attributable to an asset, other costs such as finance expense, capital taxes and benefits are not readily estimated on an incremental basis. In addition, the following table does not include operating, administrative & maintenance costs specific to these assets are not discernable because these costs are not specifically tracked on a per transmission asset basis. As indicated in the response to IGU/CENTRA I-8h, costs for general maintenance to these assets include:

- Steel valve maintenance;
- Cathodic protection system monitoring;
- Buried plant locate services; and,
- Click Before You Dig/Safety Watch.

In addition and as identified in the response to IGU/CENTRA II-1e-j, the cost of other pipe and facilities that serve the Brandon and surrounding region and form part of the overall gas infrastructure system that supplies the Koch plant needs to be considered. It is important to recognize that the interconnected pipelines and related facilities are not considered to function independently of each other and as such, this analysis is incomplete in terms of capturing all costs associated with delivering gas to the Koch Fertilizer plant.

In the context of these foregoing caveats, please see the revenue requirement analysis as requested below:

NPS 6 & 12 DIAMETER PIPELINE
(In Millions of Dollars)

For the year ended March 31	**2014**
Finance Expense	0.1
Depreciation	0.1
Capital & Other Tax	0.0
	0.2

NPS 6 & 12 DIAMETER PIPELINE
(In Millions of Dollars)

For the year ended March 31	**2020**
Finance Expense	0.1
Depreciation	0.1
Capital & Other Tax	0.1
	0.2

REFERENCE:

Koch's Contract with Centra

9. If the Customer or its authorized agent causes delivery imbalances relating to the delivery of gas to the Centra distribution system, Centra may impose any imbalancing costs or charges on the Customer, provided that and to the extent that any such imbalancing costs or charges are imposed on Centra. DELIVERY IMBALANCES

QUESTION:

Centra's tariff states that Special Contract Class customer services are governed by terms of the individual contract, and Koch's contract states imbalances may be subject to costs or charges provided such imbalances caused Centra to incur costs or charges. Please reconcile the language in Koch's contract with Centra's intent to charge Koch for daily and cumulative imbalances.

RESPONSE:

No reconciliation is necessary as the language on Delivery Imbalances within Koch's contract with Centra as referenced is not inconsistent with the intent of Centra's balancing fee proposal within the Application.

In any event, the terms and conditions of Koch's contract with Centra, including the payment for natural gas services and the rates associated therewith, are expressly subject to the jurisdiction of the Public Utilities Board of Manitoba ("PUB") and may be changed by the PUB from time to time.

The legislated authority of the PUB to establish just and reasonable rates for natural gas services within Manitoba cannot be fettered or constrained by individual contractual arrangements. The PUB's legislated mandate enables and permits the PUB to amend or alter contractual or tariffed terms from time to time when doing so is in the public interest.

The PUB must also consider cross-subsidization as amongst different groups of customers in its deliberations. To address the current unfairness and inequity between Sales Service and T-Service customers, Centra has proposed a measured and reasonable approach to balancing fees which:

1) Mitigates the impacts on T-Service customers;
2) Is modelled on the NEB-approved TCPL Mainline balancing fee structure;
3) Was finalized only after extensive consultation with T-Service customers, which resulted in changes to Centra's original proposal; and
4) Was communicated to impacted parties almost 3 years in advance of the proposed implementation date of November 1, 2019.

REFERENCE:

PUB I-1 a-b

QUESTION:

a) In Centra's December presentation to Koch, balancing fees were not mentioned. Please explain this important oversight.

RESPONSE:

The issue of balancing fees had already been extensively canvassed by Centra with Koch by the time of the December 2018 presentation. In addition to the consultations described in PUB-CENTRA I-149b, which applied equally to Koch as to each T-Service Customer, Centra conducted a conference call with Koch on November 27, 2018, just prior to filing the GRA with the PUB, to advise that Centra would be proposing changes to its Special Terms and Conditions of Service for T-Service customers that included changes to balancing fees. In addition, on December 7, 2018, Centra followed up with an email which provided a summary from the call.

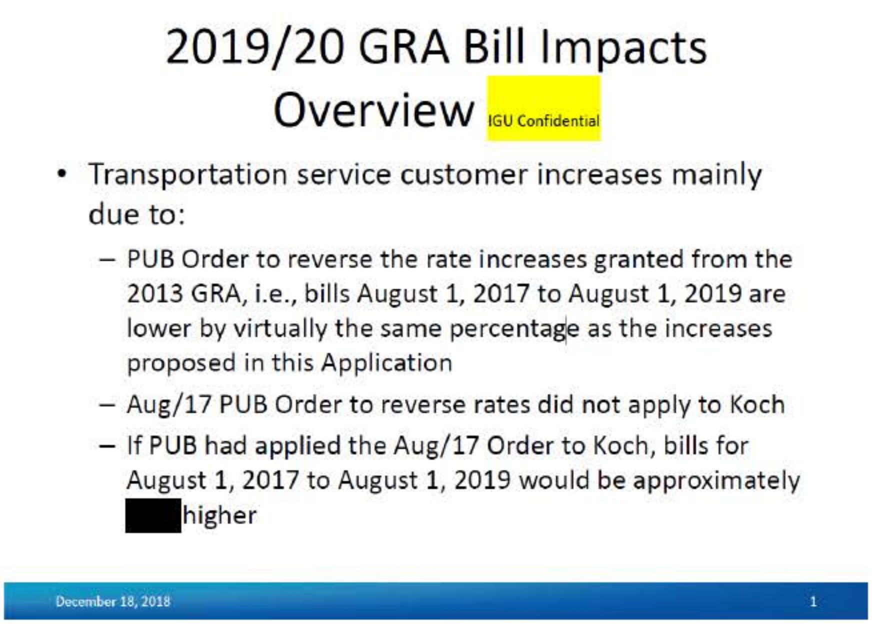
Topics covered in the conference call and the follow-up summary were the changes Centra was seeking, the rationale for the changes, the mitigation tools available to customers, a review of the reporting that Centra has been providing Koch, and, information on how Koch could register as an interested party or an intervenor in the GRA proceeding.

REFERENCE:

PUB I-1 a-b

QUESTION:

b) Please refer to Centra's presentation to Koch in December 2018 page 6 (attached). Can Centra explain clearly what this slide is trying to say?



2d

c) Is Centra able to amend slide 6 provided to Koch to have a clear explanation of the history of Koch's charges and how this related to the proposed increase in this GRA?

RESPONSE:

b) The slide above is intending to indicate the following:

- The bill impact for T-Service customers (other than Koch) is primarily due to the effect of reversing the bill decrease that these customers experienced as a result of reversal of the non-gas rate components on August 1, 2017 (Directive 5 in Order 108/15).
- The Special Contract class was not subject to the rate reversion on August 1, 2017 and therefore their rates remained unchanged.

- If the Special Contract class had been subject to reversion on August 1, 2017, the class would have experienced an annual bill increase of approximately [redacted]% at that time. 2d

c) The following table provides the history of the Bill Impact for Special Contract flowing from the previous applications:

Application	Billed Rate Impact $	Billed Rate Impact %	Base Rate Impact $	Base Rate Impact %
August 1, 2017 Non-Gas Rate Reversion	[redacted]			
2013/14 GRA				
2010/11 GRA (2010/11TY)				
2010/11 GRA (2009/10TY)				
2008/09 GRA (2008/09TY)				
2008/09 GRA (2007/08TY)				

2d

REFERENCE:

IGU/Centra I-27 Heating Value Deferral, IGU/Centra I-1a-c. In addition, Manitoba Hydro's response to Cost of Service Study recommendations by Christensen Association Energy consulting shown below (source: MH Website rate case documents).

> **Recommendation 30:** With respect to heating value deferral, CA recommends that Centra should include only customers with monthly bills that are determined according to energy sales volumes in the disposition of differentials attributable to heating value (page 31).
>
> **Centra's Position and Rationale:** Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulate if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that
>
> occurs when the energy content of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.

QUESTION:

a) Why has Centra decided to not follow the recommendation from Christensen Associates as they recommended that Koch should not participate in the disposition of the heating value deferral?

b) As the vast majority of Koch's payments to Centra are constant and independent of volume, please explain why Koch should pay a heating value deferral charge that varies with volume?

RESPONSE:

a) Centra continues to be supportive of the recommendation made by Christensen Associates that the Special Contract class should not be included in the refund or collection of the balance in the Heating Value Deferral Account. However, when considering the appropriate time to implement the recommendation, it is necessary to take into account the regulatory principles of fairness and equity as between and amongst customer classes with respect to the refunds and collections to date with respect to the Heating Value Deferral Account.

For illustration purposes, the total Heating Value Deferral Account balance allocated to the Special Contract class since 2002/03, as well the amount Centra is proposing to collect from the Special Contract class as part of this GRA, is shown in the summary table below:

[redacted]

2d

Over the period 2002-2016, the Special Contract class received a net refund of [redacted], 2d
a refund that would have otherwise been allocated to other customer classes under the Christensen recommendation. The total heating value (including carrying costs) accumulated in the Heating Value Deferral Account over the 2015/16, 2016/17 and the 2017/18 years that Centra is proposing to collect from the Special Contract class as part of this GRA is [redacted]. If Special Contract customers are excluded from the collection 2d
of the balance in the Heating Value Deferral Account in the current GRA, this amount would need to be allocated to, and collected from, the other customer classes (subject to PUB approval).

With the Special Contract class having received a net [redacted] benefit from this deferral 2d
over the course of 15 years, Centra believes there is a fairness argument that dictates that the current balances to be collected from customers should be apportioned in the same manner that previous balances have been refunded. At the same time the current proceeding allows for all parties to advise of their positions about appropriate treatment going forward.

b) In accordance and consistent with the long-standing PUB approved treatment for refunding or collecting the Heating Value Deferral Account, the Heating Value Deferral Account balance is to be collected from all customer classes on a volumetric basis as part of this GRA.

REFERENCE:

IGU/CGM-I-1a-c; and Centra Gas' historical experience, Tab 12 – Terms and Conditions of Service, page 4 of 13

PREAMBLE TO IR (IF ANY):

On page 2 of the referenced IR response, Centra provides its historical net cost experience for Balancing Fees from 2011/12 to 2018/19 forecast.
On page 4 of Tab 12, Centra states that: T-Service customers in Manitoba faced increased operating challenges when the National Energy Board approved pricing discretion for short term discretionary services including Interruptible Transportation ("IT") on the TCPL Mainline effective July 2013.

QUESTION:

a) Please expand the table provided on page 2 of the response to show the gross balancing fees for each year provided and a separate column for fees recovered from T-Service customers. Please provide an additional column if necessary to reconcile to the net balancing fees with an explanation of any additional reconciling items.
b) Please confirm that the net balancing fee costs shown on page 2 of the response are currently recovered entirely through the Transportation PGVA. If not confirmed, please provide an explanation for how these costs are currently recovered and a high level estimate of what portion of those costs are recovered through other mechanisms.
c) Please confirm whether or not T-service and special contract customers are currently charged for balances in the Transportation PGVA. If yes, please provide a rough estimate for each year of the percentage of the net balancing fees on page 2 of the IR response that are recovered from T-service and special contract customers. Please provide the response at a level of aggregation or detail that can be made public.
d) Please confirm whether or not the impacts of the NEB's 2013 Decision on short-term discretionary services continue to apply in the 2019/20 test year and beyond.
e) Please provide a copy of the 2013 NEB Decision mentioned on page 4 of Tab 12.

RESPONSE:

a) The table below provides the requested information:

Gas Year	TCPL Balancing Fees	Third Party Administration Fees	Total Balancing Fees	TCPL Balancing Fees Recovered from T-Service Customers	Balancing Fees Recovered from Sales Service Customers
2017/18	$273,504	$1,200	$274,704	($75,210)	$199,494
2016/17	$243,856	$1,200	$245,056	($87,693)	$157,363
2015/16	$214,739	$1,200	$215,939	($12,896)	$203,043
2014/15	$311,795	$1,200	$312,995	($92,083)	$220,912
2013/14	$377,195	$0	$377,195	($122,761)	$254,434
2012/13	$248,679	$0	$248,679	($54,551)	$194,128
2011/12	$245,720	$0	$245,720	($42,121)	$203,599

The reconciling item is the column titled Third Party Administration Fees. Centra pays $100 per month to a third party related to its transportation capacity on the Centra Transmission Holdings Inc. ("CTHI") pipeline. Given the immateriality of this annual amount, it has been included in the balancing fees line item of the Transportation PGVA since Centra contracted for CTHI capacity in the 2014/15 Gas Year to serve a customer in the R.M. of Piney.

Given Centra's current balancing fee practice as described in the response to PUB/CENTRA I-145e, Centra has only recovered balancing fees from the four largest T-Service customers within the timeframe captured in the table above.

b) Confirmed.

c) T-Service customers, including special contract customers, are not impacted by balances in the Transportation PGVA.

d) TCPL Mainline pricing discretion was most recently approved by the NEB in its RH-001-2018 decision to the end of calendar year 2020, thus Centra can confirm that this market condition will be in place for the 2019/20 test year. The settlement or hearing before the NEB on the matter of the post-2020 environment for the TCPL Mainline will determine the future of TCPL Mainline pricing discretion beyond December 31, 2020.

e) The following link is to the NEB's RH-003-2011 decision which provided the original approval of pricing discretion on the TCPL Mainline effective July 1, 2013:

https://apps.neb-one.gc.ca/REGDOCS/File/Download/939800

The relevant sections of the decision are at PDF page 21 of 276, Greater Pricing Discretion; and PDF pages 139 – 148 of 276, section 8.1: Flexible Pricing of IT and STFT. Since the issuance of this decision, the NEB has approved the continuation of pricing discretion on the TCPL Mainline in both its RH-001-2014 and RH-001-2018 tolls decisions.

REFERENCE:

PUB/CENTRA IGU/CGM-I-1a

PREAMBLE TO IR (IF ANY):

Centra states in this response:
"Any amounts collected from T-Service customers will be refunded to Sales Service Customers dollar for dollar."

QUESTION:

a) Can Centra please confirm, per the quote above, that any balancing fees collected from T-Services customers that are surplus to any balancing fees charged to Centra by TCPL will not be refunded back to T-Service Customers. If not, why?
b) How will Centra reward those companies who balance their gas better than others? Can you provide an illustrative example?
c) In Centra's view, have Sales Service customers ever benefitted from avoiding balancing charges due to T-service customers having offsetting loads?
d) In Centra's view, would removing all T-service and special contract customers (i.e. removing the loads entirely, not transitioning those loads to sales service) from the system result in higher balancing costs for existing sales service customers? Why or why not.

RESPONSE:

a) Confirmed, because T-Service imbalances result in costs borne by Sales Service customers as described in the responses to PUB/CENTRA I-147a and PUB/CENTRA II-58d. Additionally, please see the response to PUB/CENTRA II-58c which explains the reasons for balancing fees not being cost-based.

b) The premise of this question inappropriately suggests that it is Centra's role to "reward" those companies who balance their gas better than others. To the contrary, T-Service customers have a contractual obligation to balance their accounts on a daily and intra-day basis, which is consistently not being met by the majority of T-Service customers.

Under Centra's balancing fee proposal, companies who "balance their gas" (i.e., balance their nominations with consumption) better than others will pay relatively less or no balancing fees. An illustrative example of this was provided in the response to IGU/CENTRA I-26.

c) Please see the response to PUB/CENTRA I-148 b.

d) All else equal, removing T-service customers including special contract customers from the system would currently result in lower balancing costs for Sales Service customers because:

   i. Centra actively monitors and manages its Sales Service account balance on a daily and intra-day basis while most T-Service customers do not; and
   ii. Sales Service customers absorb the vast majority of costs (direct and indirect) associated with T-Service imbalances.

   Under Centra's balancing fee proposal, cross-subsidization of T-Service customers by Sales Service customers would be mitigated because more appropriate incentives would exist for T-Services customers to balance their accounts on a daily and intra-day basis.

REFERENCE:

PUB/CENTRA I-147 a-f

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm if the net TCPL Balancing Charges for 2015/16 ($201,843); 2016/17 ($156,163); and 2017/18 ($198,294) in the response to PUB/CENTRA I-147 (a) are equivalent to the values provided in page 2 of the response to IGU/CENTRA I-1 (a-c). If not, please provide an explanation.
b) In Centra's view, do sales service customers properly bear any cost responsibility for the Net balancing charges outlined in part (a) above?
c) Please provide a quantified estimate of the annual costs Centra incurs in terms of opportunity costs in the form of foregone capacity management revenue; and further direct costs in terms of higher commodity costs associated with the delay of transactions as described in the response to PUB/CENTRA I-147(a). Please clearly state all assumptions used in developing the estimates.
d) Please confirm:
    i. that the response to PUB/CENTRA I-147 b indicates that Centra would have charged T-service customers $920,602 in 2016/17 and $760,191 in 2017/18 if Centra's proposed balancing fees had been in place for those periods and customers did not alter their operating behaviour. If not confirmed, please provide a detailed explanation.
    ii. Whether or not any amounts in addition to those in part (i) would have been collected from special contract customers.
e) Please provide a version of the table in the response to PUB/CENTRA I-147 (a) that shows the Net TCPL Balancing Charges Applicable to Sales Service Customers assuming Centra's proposed balancing fee structure had been in place beginning in 2015/16 and customers did not alter their behaviour.

f) Please describe the reserve buffer that Centra uses on a daily basis to address the uncertainty of T-Service imbalances. Please provide the quantitative daily amount and if it changes seasonally, making sure to provide the peak and minimum.
g) How does Centra know the daily gas requirements of System Gas Users? How does Centra manage the daily gas uncertainty of System Gas Users?
h) Please describe the reserve buffer that Centra uses on a daily basis to contend with the uncertainty of System Gas imbalances. Please provide the quantitative daily amount and if it changes seasonally, making sure to provide the peak and minimum.
i) With respect to the response to PUB/CENTRA I-147 (d), please provide a reference to previous filings and PUB decisions that support the statement "The premise on which T-Service was originally introduced.....is that a customer who elects T-Service is contractually committed to manage its own upstream gas arrangements, including the need to forecast and balance its account on a daily basis."
j) Centra states in response to PUB/CENTRA I-147 (d) "If a T-Service customer wishes to be part of a pool of customers, Centra provides other service options with this service attribute".
   Would Centra consider:
k) Allowing several T-Service customers to pool their service together through a single nominating agent? Please explain why or why not.
   ii. Allowing shippers to trade imbalances between each other to make-up imbalances? If so, how would Centra propose to implement this? If not, why not?

RESPONSE:

a) Not confirmed. Please see the response to IGU/CENTRA II-5a for a reconciliation and explanation of historical balancing fees.

   b) This question should be considered within the broader context of the total cost of T-Service imbalances, rather than TCPL balancing fees alone, however it is Centra's view that Sales Service customers should reasonably bear balancing costs to the extent they caused them to be incurred. Currently, Sales Service customers are unduly cross-subsidizing T-Service customers and have been for a number of years.

By contrast, Centra's proposed balancing fee structure would directionally ensure fairness in relation to balancing costs which include TCPL balancing fees.

c) The quantum of direct and indirect (i.e., opportunity) costs associated with T-Service imbalances is material and exceeds the direct cost of balancing fees incurred from TCPL. As described in the response to parts f) and h) below, at least [redacted] of Centra's operational buffer is associated with the uncertainty impact that T-Service customers currently have on Centra's daily decision-making, which drives reduced Capacity Management ("CM") revenue and increased costs: 1c

- During the summer months, accommodating the uncertainty of T-Service imbalances results in both foregone CM revenue and increased commodity costs given the required delay of transactions. The delay of a sale of excess capacity results in foregone CM revenue as a result of moving from a day-ahead transaction to an intra-day transaction, the historical average of which is approximately $0.25/GJ. Similarly, higher commodity costs result from delaying a commodity purchase or sale to a later intra-day nomination window in order to balance the MDA. While the continuous change in spot market prices makes quantification impractical in this case, the diminished liquidity at later nomination windows definitely results in lower value for Centra's gas sales and higher costs for Centra's gas purchases. Given variability in weather and market conditions, Centra estimates summer opportunity and direct costs of at least [redacted]. 1a
- During the winter months, the opportunity costs associated with accommodating the uncertainty of T-Service imbalances take the form of foregone CM revenue due to the requirement of [redacted] 1a, 1c and reducing the volume of [redacted]. However, these volumes can vary widely based on weather and operational requirements. As a result, foregone revenue during the winter period exists but cannot be estimated with accuracy.

[1] [redacted] 1a

In summary, while not all direct and indirect costs can be quantified with precision given the challenges associated with valuing transactions that were never executed and the multitude of different and changing market conditions (such as seasonal differences in portfolio optimization activities, basis differentials in the market, and pipeline restrictions) that impact operational decisions on the day, Centra would not have undertaken the significant effort associated with introducing and refining a T-Service balancing fee structure if the cost to Sales Service customers of the status quo was not material, in fact exceeding the direct cost of balancing fees incurred from TCPL.

Additionally, there is no benefit to Centra of balancing fees other than to:

i. Incent improved balancing performance for the important reasons described in the response to PUB/CENTRA II-58c;
ii. Minimize the inefficiency and associated cost of Centra staff having to coax T-Service customers and/or nominating agents on a daily basis to do that which is a requirement of the service; and
iii. Directionally address an unfairness that has existed for a number of years.

d)

i. Confirmed.
ii. The information in the table in the response to PUB/CENTRA I-147b is inclusive of special contract customers. Thus, no amounts in addition to those provided in this table would have been collected from special contract customers.

e) Centra does not agree with the premise of this question which is to assume that T-Service customers will make no attempt to improve their balancing performance once the incentive of balancing fees are in effect. This is unrealistic. If a financial incentive is implemented in the form of the proposed balancing fee structure, it is reasonable to expect that T-Service customers' balancing performance will improve.

Additionally, Centra has already provided two and a half years of pro-forma reporting to all T-Service customers and nominating agents, and summarized this information in the response to PUB/Centra I-147 b). Accordingly, Centra respectfully declines to calculate pro-forma results for a further one year historical period which would be labour intensive and not value-added.

f) and h)

The operational buffer referenced in the response to PUB/Centra I-147 a) and in part c) above varies daily based on a number of factors including:

i. weather (which drives consumption);
ii. the season within which Centra is operating (which influences the range of potential weather to which Centra needs to be prepared to respond);
iii. market conditions (e.g., whether restrictions are in place on any of the pipelines on which Centra transports gas which may influence the amount of buffer used on the day); and
iv. the current uncertainty related to whether and to what degree T-Service customers will balance their accounts.

This operational buffer ranges between [redacted] of Centra's operational buffer. 1c

g) Centra forecasts the daily gas requirements of Sales Service customers (i.e., system-supplied and WTS-supplied customers) by maintaining a database of historical consumption data that it cross-references with key weather variables (e.g., temperature, wind chill, cloud cover) as provided by multiple weather forecast services for the coming day(s) and actual hourly metered consumption data from throughout the Manitoba market. Centra is also attuned to market conditions as described in parts f) and h) above.

Once daily consumption has been forecast, including defining a range of consumption with a low end, the pick, and a high end, Centra then actively monitors hourly consumption relative to forecast and has the following options available to it to respond to variation from forecast:

i. Increase or decrease supply by adjusting nominations to match updated consumption information at day-ahead and intra-day nomination windows, as required (at up to 5 nomination windows per gas day during summer and at up to 6 nomination windows per gas day during winter);

ii. Use the TCPL Mainline's Park and Loan Service ("PALS")[2]; and/or

iii. Execute purchases (if drafting) and sales (if packing) of gas in the market with other counterparties who operate on the TCPL Mainline.

By comparison, there is a current T-Service customer who advised during Centra's customer consultations that it hadn't evaluated its daily consumption *in a year*, another who routinely submits a monthly forecast of gas consumption to its nominating agent and to Centra, and others who forecast their consumption on a weekly basis at best, all within a gas market that operates <u>on a daily and intra-day basis</u> and regardless of their contractual obligation to balance their accounts on a daily basis.

i) Centra did not rely on previous filings and PUB decisions to support its statement that the premise on which T-Service was originally introduced, and how it is designed and functions. A customer who elects T-Service is contractually committing to manage its own upstream gas arrangements including the need to forecast and balance its account on a daily basis. The current terms and conditions of T-Service outline this requirement, as described in Centra's evidence.[3]

j) and k), i) and ii)

The premise of these questions suggests that Centra would act as a clearing house for commodity imbalances to and from T-Service customers. Centra is neither set up, nor compensated, to perform this function which would inevitably result in greater costs and effort on Centra's part. Given the extent to which Sales Service customers are, and have been, cross-subsidizing T-Service customers, Centra does not support the addition of yet another layer of complexity and administrative cost for the benefit of T-Service customers and nominating agents and to the detriment of Sales Service customers. Sales Service, including both system supply and WTS options, is available for customers that do not wish to manage their upstream gas arrangements on a daily basis using

[2] Subject to availability and as described in the response to PUB/Centra I-149 d).
[3] Tab 12, pages 2-3.

existing market options, while Centra's balancing fee proposal is low cost and appropriately incents improved balancing performance.

REFERENCE:

PUB/CENTRA I-149 c and IGU/CENTRA I-24 a and b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please itemize and elaborate on the 'significantly more economic alternatives that Centra routinely avails itself of and which are also available to T-Service customers or their nominating agents' referenced in the response to IGU/CENTRA I – 24 (a) and (b).
b) Has Centra ever investigated on its own or been approached by another party about the possibility of developing new local storage options in Manitoba? If not, when not. If yes, please discuss why such options have not been developed.

RESPONSE:

a) Any of the following actions are available to a T-Service customer or its nominating agent in order to balance their account within tolerance:
   i. Increase or decrease supply by adjusting nominations to match updated consumption information at day-ahead and intra-day nomination windows, as required;
   ii. Use the TCPL Mainline's Park and Loan Service ("PALS")[1]; and/or
   iii. Execute purchases (if drafting) and sales (if packing) of gas in the market with other counterparties who operate on the TCPL Mainline.

   Some T-Service customers routinely avail themselves of these options but most T-Service customers (or their nominating agents) do not, the latter group balking at the associated costs relative to their current free option to swing on Centra's assets which are contracted and paid for by Sales Service customers.

[1] Subject to availability and as described in the response to PUB/CENTRA I-149d.

Any of the readily available and industry recognized above-noted options are immensely more cost effective than would be options like developing local storage[2] and peak shaving facilities, which could require capital investment in the hundreds of millions of dollars.

b) Centra has investigated the possibility of developing local storage in Manitoba but it is not economic relative to market alternatives.

[2] PUB/CENTRA I-149c.

REFERENCE:

IGU/CENTRA I-22(b) and Attachment 3

PREAMBLE TO IR (IF ANY):

Regarding Centra's future imbalance resolution and make-up process and its plan to mirror TCPL Mainlines approach to imbalances excerpt from Centra rate application, tab 12: charging for imbalances at 50% of the current TCPL Mainline balancing fees. In order to do so, Centra proposes to revise the wording of Section V. N), formerly O) (page 32) of the Ts & Cs to indicate that Centra may impose balancing fees on the customer mirroring the existing and longstanding TCPL Mainline approach to imbalances.

QUESTION:

Will Centra be using TCPL's tariff options for shippers to resolve imbalances in the next month following an imbalance being incurred? [see TransCanada Pipeline Gas Tariff, page 40]

RESPONSE:

Centra is not impacted by the referenced section of TCPL's tariff, nor is it proposing that T-Service customers in Manitoba would be impacted by it. Centra has been providing detailed pro-forma reporting of its balancing fee structure to all T-Service customers and nominating agents from October 2016 to April 2019 (to date). Attachment 2 to PUB/CENTRA I-149b is an example of this pro-forma reporting, which demonstrates that this section of TCPL's tariff is not relevant for T-Service customers in Manitoba.

REFERENCE:

PUB/CENTRA I-117 a-b and PUB/CENTRA I-146 a-c

PREAMBLE TO IR (IF ANY):

Centra states in the response to PUB/CENTRA I-177 a: Centra also put forward the position that unlimited pricing discretion for short-term services on the TCPL Mainline is unnecessary and should be constrained. However, the NEB approved the continuation of the existing Mainline pricing discretion for Interruptible Transportation and Short-Term Firm Transportation services for the 2018 to 2020 period.

QUESTION:

a) Please confirm if it is Centra's understanding that for the post-2020 toll application the NEB may re-evaluate continuation of the Mainline pricing discretion and that it could be discontinued starting in 2021.
b) If pricing discretion on the Mainline did not exist, would Centra develop a different balancing mechanism for T-Service? If so, please describe the mechanism and how it would be different.
c) Please confirm that Centra does not purchase TransCanada mainline capacity for T-Service customers and therefore any future value the Centra may derive from the adjustment of any deferral account referred to as the Long-Term Adjustment Account would accrue directly to system gas users. If not confirmed, please provide an explanation.
d) What mechanism could Centra propose to ensure a balance of costs/credits for T-Service customers.

RESPONSE:

a) Please see the response to IGU/CENTRA II-5d.

b) Centra would proceed with the current form of its balancing fee proposal for the important reasons described in the response to PUB/CENTRA II-58c.

c) and d)

Confirmed that Centra does not contract for TCPL Mainline capacity for T-Service customers. In terms of the TCPL Mainline deferral account referred to as the Long-Term Adjustment Account ("LTAA"), the magnitude and direction of its balance at the end of 2020 is unknown, as is the NEB's decision on the amortization of same and to whose account. However, in the event that the LTAA balance at the end of 2020 is owing to customers and the NEB makes a decision similar to its RH-001-2018 tolls decision as it relates to LTAA amortization, Centra (on behalf of Sales Service customers) and T-Service customers would obtain the identical benefit in the form of a further reduction in TCPL Mainline tolls from the current RH-001-2018-approved levels, all else equal on the Mainline.

The only scenario that Centra envisions as potentially negating or reducing the benefit that T-Service customers would obtain relative to Centra's Sales Service customers in these circumstances, is if a T-Service customer has agreed to fixed transportation tolls in its contract with its nominating agent. This would be unrelated to fairness between Sales Service customers and a T-Service customer on Centra's system, rather it would relate to the different objectives and risk tolerances of Centra (on behalf of Sales Service customers) and the T-Service customer in this example. As such, no mechanism to ensure a balance of costs/credits for T-Service customers is required.

REFERENCE:

IGU/CENTRA I-26

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the IR response.

QUESTION:

a) Please confirm:
   i. Did Centra change its proposed daily and cumulative tolerances between April 2018 and April 2019? If so, please describe how and why Centra's proposal changed.
   ii. If changes were made please provide an outline of how this was communicated to impacted customers.
   iii. Was the response to IGU/CENTRA I-26 prepared based on the April 2018 or April 2019 proposed daily and cumulative tolerances?

b) Please update the response to show the balancing fees that would be incurred in the scenario described in IGU/CENTRA I-26 under both the proposal from the April 2018 period and the proposal in the April 2019 period.

RESPONSE:

a)
   i. Yes, Centra revised absolute daily and cumulative tolerances for some T-Service customers based on updated average daily consumption over the most recently completed gas year and after a review to ensure relative consistency of absolute tolerances amongst the majority of T-Service customers. Please also see the responses to PUB/CENTRA II-57a.

   ii. Following the revisions to absolute daily and cumulative tolerances and in conjunction with the first pro-forma report sent to customers for the 2018/19 gas year (i.e., the pro-forma reports related to balancing activity for the month of November 2018), Centra identified any changes to absolute daily and cumulative tolerances to impacted customers in the e-mails that accompanied their pro-forma reporting, and indicated that going forward, the pro-forma reporting would be based on these revised absolute tolerances.

To ensure clarity on this matter, T-Service customers have not yet been billed on the basis of Centra's proposed balancing fee structure. Rather, pro-forma reporting is being provided to assist customers in understanding potential impacts and preparing for the transition to balancing fee implementation.

iii. The response to IGU/CENTRA I-26 was based on the absolute tolerances being used by Centra for pro-forma reporting as of November 1, 2018, for the 2018/19 gas year.

b) Centra's balancing fee proposal and response to IGU/CENTRA I-26 is based on the most current assumptions for pro-forma balancing fee determination. However, if the absolute daily and cumulative tolerances being used for pro-forma reporting prior to November 1, 2018 were alternatively used in responding to IGU/CENTRA I-26, a customer with approximately 2,000 GJ/day of average daily consumption would have been assigned an absolute daily tolerance +/- 100 GJ and an absolute cumulative tolerance of +/- 200 GJ. Accordingly, the following daily and cumulative balancing fees would result:

- <u>Daily Balancing Fees - $19</u>
  Given the daily imbalance of 120 GJ and the customer's absolute daily tolerance of 100 GJ, 20 GJ of pack imbalance would be subject to daily balancing fees.
- <u>Cumulative Balancing Fees - $0</u>
  There would be no cumulative fees for the pack that was not removed from the delivery area given that the imbalance of 120 GJ is less than the customer's 200 GJ absolute cumulative tolerance.

REFERENCE:

IGU/CENTRA I-27

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the Heating Value Deferral Account charges.

QUESTION:

a) Please confirm if the $2,519,879 to be recovered from customer classes in 2019/20 is the same as the sum of row 26 of Schedule 11.3.0 (a) (2014/15); row 26 of Schedule 11.3.0(b) (2016/17) and row 26 of Schedule 11.3.0 (c). If not confirmed, please provide a detailed explanation.
b) Please confirm the $2,519,879 million relates only to non-gas costs. If not confirmed, please provide an explanation.
c) Please provide a table that shows for each customer class:
    i. The total of the Heating Value dollars for each customer class from row 26 of Schedules 11.3.0 (a); 11.3.0 (b) and 11.3.0 (c).
    ii. The total Non-gas costs allocated to each customer class as shown at row 43 of Schedule 10.1.2.
    iii. The percentage of total non-gas revenues recovered through fixed customer charges.
    iv. The percentage of total non-gas revenues recovered through demand charges.
    v. The percentage of total non-gas revenues recovered through volume based charges.
d) Please discuss how variations in heating content of natural gas leads to variations in Centra's revenue collected from each of:
    i. Fixed customer charges
    ii. Demand charges
    iii. Volumetric charges
e) Page 16 of Attachment 11 to application states Centra agrees with CA's recommendation that the Special Contract rate class should not participate in the disposition of the heating value deferral. Given that statement, please explain why

Centra continues to apply the heating value margin deferral account adjustment to all customer classes as stated in the response to IGU/CENTRA I-27 (g).

f) Please discuss if in Centra's view, CA's recommendation 30 as stated on page 15 of 25 of Attachment 11 should also apply to T-Service customers. Why or why not?

g) Please confirm:

   i. The $2,519,879 million total heating value to be recovered from each customer class in 2019/20 shown in the Attachment to IGU/CENTRA I-27 was accumulated over a three year period. If not confirmed, please provide an explanation.

   ii. Centra is proposing to recover that amount over a 1-year period. If confirmed, please discuss whether or not Centra considered recovering that amount over a longer period than 1-year and if not, why not.

   iii. Please provide versions of Schedule 11.1.0 and Schedule 11.2.1 assuming the $2,519,879 amount was collected over a three year period.

RESPONSE:

a) Confirmed. Please refer to the response to part c) that provides the allocation of the total Heating Value Deferral Account for each of 2015/16, 2016/17 and 2017/18 year.

b) Centra confirms that the $2,519,879 relates only to non-gas costs.

c) Response to part i)

   The following table provides the total Heating Value Deferral Account allocated to each customer class in 2019/20 GRA:

		Total	SGS	LGS	HVF	ML	INT	SC	PS
2015/16 Heating Value (incl carrying costs)	Sch. 11.3.0 a), line 26	[redacted]							
2016/17 Heating Value (incl carrying costs)	Sch. 11.3.0 b), line 26								
2016/17 Heating Value (incl carrying costs)	Sch. 11.3.0 c), line 26								
Total Heating Value (including carrying costs)		2,519,879							

2d,1e

   Response to ii), iii), iv) and v)

   Please see Attachment 1 to this response.

d) Variations in heating content would not have an effect on the recovery of costs through fixed monthly charges.

Variations in heating content would have some effect on the recovery of capacity costs through demand charges, as billing demand is measured as the peak daily consumption for the month. Therefore, variation in heating content may have a slight impact on the demand level measured on a peak day for a customer.

Variations in heating content would have a greater effect on the recovery of costs through volumetric charges where fixed costs are largely being recovered through volumetric charges as found in the SGS and LGS customer classes.

e) In the period of 1999 to 2014 the Heating Value Deferral Account was consistently refunding amounts to customers as the heat content of gas was lower than the heat content level used in setting rates. In that time period Centra applied those refund amounts to all customer classes.

Given that all customer classes participated in the refund of those amounts over that period of time, Centra has continued to include all customer classes in the recovery of amounts owing to Centra in the period of time since the heat content of natural gas has increased above [redacted] $GJ/10^3\ m^3$ as shown in the response to part l) of IGU/Centra II-12. 1d

f) The recommendation by Christensen Associates specifically identified the Special Contract class due to the fixed cost recovery associated with the two part rate design for that class.

T-Service is a service option and not a customer class. T-Service customers may be found in the HVF, Mainline and Power Station classes. As HVF and Mainline customers are charged through a three part rate design, Centra sees no justification in applying the Christensen Associates conclusion to T-Service customers. Further Centra sees no justification in treating customers who select different service options within the same rate class (T-Service and Sales) differently.

g)

i. The $2,519,879 referenced in the question is the total heating value (including carrying costs) accumulated in the Heating Value Deferral Account in 2015/16, 2016/17 and the 2017/18. This amount will be recovered from all customer classes as determined through Centra's cost allocation methodology.

ii. Confirmed. Centra did not consider recovering this amount over a period of greater than one year. The Heating Value Deferral Account is one of four variance accounts related to non-Primary Gas rates that are tracked and disposed of on a regular basis, but not necessarily annually. Historically, the Heating Value Deferral Account balance has been disposed of over a one year period, regardless of either the balance or the period it was accumulated over. The only occasion in recent history when any of the non-Primary Gas deferral accounts have been disposed of in a period greater than one year was the 2013/14 Supplemental Gas PGVA when the balance exceeded $45 million.

iii. Please see Attachment 2 to this response. For purpose of preparing this response Centra did not estimate additional carrying costs associated with the 3-year recovery period. Centra assumed the total balance of $2,519,879 to be recovered over 3 years.

			System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
Non-Gas Revenue																
part ii)	Total Non-Gas Revenue (per Sch. 10.1.2, line 43)		148,519,256	102,632,670	32,455,799	6,824,301	8,233	2,057,841	2,246,833	157,798	769,561	[redacted]			21,155	1e
			100%	100%	100%	100%	100%	100%	100.00%	100%	100%	100%	100%	100%	100%	
part iii)	BMC Non-Gas Revenue (IGU-Centra I-15 Attachment, line 47)	($)	58,718,928	[redacted]												1e
	% of total non-gas revenues recovered through BMC	(%)	40%													
part iv)	Demand Transportation (IGU-Centra I-15 Attachment , line 49)		180,282	[redacted]												
	Demand Distribution (IGU-Centra I-15 Attachment, line 50)		5,016,453													1e
	Total Demand Non-Gas Revenue	($)	5,196,735									0	0	0	0	
	% of total non-gas revenues recovered through demand charges	(%)	3%													
part v)	Commodity Transportation (IGU-Centra I-15 Attachment , line 52)		5,806,226	[redacted]												
	Commodity Distribution (IGU-Centra I-15 Attachment , line 53)		78,797,365													1e
	Total Commodity Non-Gas Revenue	($)	84,603,592													
	% of total non-gas revenues recovered through volumetric charges	(%)	57%													

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

BILLED VS. BILLED

	Load Factor	Annual Use 10³m³	Annual Use Mcf	FEB 1/19 APPROVED BILLED RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$218	$386	($18)	-4.5%
		1.98	70	$168	$0	$468	$636	$168	$0	$432	$600	($36)	-5.6%
(Typical Residential Customer)		**2.22**	78	$168	$0	$523	$691	$168	$0	$483	$651	($40)	-5.8%
		2.80	99	$168	$0	$662	$830	$168	$0	$611	$779	($51)	-6.1%
		3.20	113	$168	$0	$755	$923	$168	$0	$697	$865	($58)	-6.3%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$802	$970	($66)	-6.4%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,469	$2,637	($204)	-7.2%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,060	$2,984	($12)	-0.4%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,816	$11,740	($63)	-0.5%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$123,612	$124,536	($723)	-0.6%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,097	$77,395	$78,109	$167,601	($954)	-0.6%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,097	$48,372	$78,109	$138,578	($10,792)	-7.2%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,097	$80,619	$130,182	$222,899	($17,105)	-7.1%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,097	$161,239	$260,365	$433,701	($32,887)	-7.0%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,097	$352,897	$569,850	$934,844	($70,406)	-7.0%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,097	$717,177	$1,158,083	$1,887,357	($141,717)	-7.0%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,097	$20,794	$62,959	$95,851	($15,123)	-13.6%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,097	$25,798	$78,109	$116,005	($18,444)	-13.7%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,097	$42,997	$130,182	$185,277	($29,858)	-13.9%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,097	$85,994	$260,365	$358,456	($58,393)	-14.0%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,097	$188,212	$569,850	$770,159	($126,231)	-14.1%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,097	$382,495	$1,158,083	$1,552,675	($255,169)	-14.1%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,374	$23,659	$75,131	$10,661	16.5%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$166,584	$100,096	$278,778	$49,376	21.5%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$266,535	$160,154	$438,786	$79,795	22.2%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$21,000	$23,659	$56,756	$7,279	14.7%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,845	$100,096	$201,038	$35,068	21.1%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$142,152	$160,154	$314,403	$56,903	22.1%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,169	$14,982	$24,100	$42,251	($392)	-0.9%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,169	$20,975	$33,740	$57,884	($501)	-0.9%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,169	$29,965	$48,200	$81,333	($665)	-0.8%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,969	$96,885	$274,590	$384,444	($98,388)	-20.4%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,969	$484,423	$1,372,950	$1,870,342	($430,858)	-18.7%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,969	$968,846	$2,745,900	$3,727,715	($846,445)	-18.5%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,969	$51,672	$274,590	$339,231	($67,196)	-16.5%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,969	$258,359	$1,372,950	$1,644,278	($274,896)	-14.3%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,969	$516,718	$2,745,900	$3,275,587	($534,522)	-14.0%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,969	$747,866	$3,974,249	$4,735,084	($766,803)	-13.9%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$269,492	-$609	$281,852	$54,926	24.2%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$346,490	-$784	$358,675	$74,982	26.4%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$846,975	-$1,915	$858,029	$205,348	31.5%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,729	-$609	$156,089	$13,813	9.7%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,795	-$784	$196,980	$22,123	12.7%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$451,720	-$1,915	$462,774	$76,136	19.7%
Special Contract	[redacted]												
Power Stations	[redacted]												2d
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,423	$40,283	$78,998	$131,705	($5,888)	-4.3%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,423	$83,924	$263,328	$359,676	($39,020)	-9.8%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,423	$419,620	$1,316,641	$1,748,684	($194,743)	-10.0%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,423	$13,428	$78,998	$104,850	($16,342)	-13.5%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,423	$44,759	$263,328	$320,511	($54,266)	-14.5%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,423	$223,797	$1,316,641	$1,552,862	($270,974)	-14.9%

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

1	**BASE VS. BASE**													
2														
3					**FEB 1/19 APPROVED BASE RATES**				**NOV 1/19 PROPOSED BASE RATES**				**BASE IMPACTS**	
4														
5		Load	Annual Use		Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	10^3m^3	Mcf										
7														
8	Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$214	$382	($13)	-3.3%
9			1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($26)	-4.1%
10	*(Typical Residential Customer)*		2.22	78	$168	$0	$504	$672	$168	$0	$475	$643	($29)	-4.3%
11			2.80	99	$168	$0	$637	$805	$168	$0	$601	$769	($36)	-4.5%
12			3.20	113	$168	$0	$727	$895	$168	$0	$686	$854	($41)	-4.6%
13			3.68	130	$168	$0	$837	$1,005	$168	$0	$789	$957	($48)	-4.7%
14			11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,428	$2,596	($146)	-5.3%
15														
16	Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,004	$2,928	$31	1.1%
17			59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,524	$11,448	$162	1.4%
18			679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,269	$121,193	$1,849	1.5%
19														
20	HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$53,466	$93,907	$159,469	($1,735)	-1.1%
21		40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$33,417	$93,910	$139,424	($2,600)	-1.8%
22		40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$55,693	$156,511	$224,302	($3,452)	-1.5%
23		40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$111,387	$313,023	$436,506	($5,580)	-1.3%
24		40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$243,787	$685,100	$940,984	($10,642)	-1.1%
25		40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$495,439	$1,392,300	$1,899,836	($20,261)	-1.1%
26		75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,365	$75,693	$102,155	($2,894)	-2.8%
27		75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$17,822	$93,907	$123,826	($3,273)	-2.6%
28		75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$29,703	$156,511	$198,311	($4,573)	-2.3%
29		75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$59,406	$313,023	$384,526	($7,823)	-2.0%
30		75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$130,020	$685,100	$827,217	($15,549)	-1.8%
31		75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$264,234	$1,392,300	$1,668,631	($30,235)	-1.8%
32														
33	HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,192	$26,000	$77,289	$12,819	19.9%
34		40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$165,814	$110,000	$287,911	$58,509	25.5%
35		40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$265,302	$176,000	$453,399	$94,408	26.3%
36		75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$20,903	$26,000	$59,000	$9,523	19.2%
37		75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,434	$110,000	$210,531	$44,561	26.8%
38		75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$141,494	$176,000	$329,591	$72,091	28.0%
39														
40	Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$14,982	$21,925	$40,076	($405)	-1.0%
41		35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$20,975	$30,695	$54,839	($519)	-0.9%
42		35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$29,965	$43,850	$76,983	($690)	-0.9%
43														
44	MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$152,761	$252,968	$418,697	($39,634)	-8.6%
45		40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$763,804	$1,264,838	$2,041,611	($137,085)	-6.3%
46		40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,527,608	$2,529,676	$4,070,253	($258,899)	-6.0%
47		75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$81,472	$252,968	$347,409	($34,517)	-9.0%
48		75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$407,362	$1,264,838	$1,685,169	($111,501)	-6.2%
49		75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$814,724	$2,529,676	$3,357,369	($207,732)	-5.8%
50		75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,179,182	$3,661,300	$4,853,451	($293,827)	-5.7%
51														
52	MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$269,030	$21,000	$302,999	$76,074	33.5%
53		40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$345,896	$27,000	$385,865	$102,172	36.0%
54		40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$845,523	$66,000	$924,492	$271,812	41.6%
55		75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,483	$21,000	$177,452	$35,176	24.7%
56		75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,478	$27,000	$224,447	$49,590	28.4%
57		75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$450,946	$66,000	$529,915	$143,277	37.1%
58														
59	Special Contract	[redacted]												
60														
61	Power Stations													
62														
63	Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,610	$87,873	$126,906	($3,890)	-3.0%
64		40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$55,437	$292,910	$360,771	($15,268)	-4.1%
65		40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$277,186	$1,464,549	$1,754,159	($75,986)	-4.2%
66		75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,870	$87,873	$109,166	($5,229)	-4.6%
67		75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,567	$292,910	$334,900	($17,221)	-4.9%
68		75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$147,833	$1,464,549	$1,624,805	($85,748)	-5.0%

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CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

	Transportation to Centra	Distribution to Customers		Primary Gas Supply	Supplemental Gas Supply[1]
		Sales Service	T-Service		
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,008.09	$1,008.09	N/A	N/A
Cooperative (CO-OP)	N/A	$264.05	$264.05	N/A	N/A
Main Line Class (MLC)	N/A	$1,080.75	$1,080.75	N/A	N/A
Special Contract	N/A	N/A	$189,667.91	N/A	N/A
Power Station	N/A	N/A	$6,559.41	N/A	N/A
Monthly Demand Charge ($/m³ /month)					
High Volume Firm Class (HVF)	$0.2950	$0.1834	$0.1834	N/A	N/A
Cooperative (CO-OP)	$0.4706	$0.1674	$0.1674	N/A	N/A
Main Line Class (MLC)	$0.4223	$0.2338	$0.2338	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0001	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0497	$0.0793	N/A	$0.0816	$0.1349
Large General Class (LGC)	$0.0481	$0.0435	N/A	$0.0816	$0.1349
High Volume Firm (HVF)	$0.0152	$0.0100	$0.0100	$0.0816	$0.1349
Cooperative (CO-OP)	$0.0023	$0.0001	$0.0001	$0.0816	$0.1349
Main Line Class (MLC)	$0.0025	$0.0015	$0.0015	$0.0816	$0.1349
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0183	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as descr bed above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after November 1, 2019

Approved by Board Order:
Effective from: November 1, 2019
Date Implemented: November 1, 2019

Supersedes Board Order: 16/19
Supersedes: February 1, 2019 Rates

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interrupt ble Service	N/A	$1,035.29	$1,035.29	N/A	N/A
Mainline Interrupt ble (with firm delivery)	N/A	$1,080.75	$1,080.75	N/A	N/A
Monthly Demand Charge ($/m³ /month)					
Interrupt ble Service	$0.1493	$0.0888	$0.0888	N/A	N/A
Mainline Interrupt ble (with firm delivery)	$0.2297	$0.2338	$0.2338	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Interrupt ble Service	$0.0080	$0.0064	$0.0064	$0.0816	$0.1343
Mainline Interrupt ble (with firm delivery)	$0.0026	$0.0015	$0.0015	$0.0816	$0.1343
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0093		
Delivery - Mainline Interrup ible Class			$0.0092		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after November 1, 2019

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory:	Entire natural gas service area of Company, including all zones
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered to natural gas distribution cooperatives
CO-OP:	For gas delivered through one meter at annual volumes greater than 680,000 m³
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,008.09	$1,008.09	N/A	N/A
Cooperative (CO-OP)	N/A	$264.05	$264.05	N/A	N/A
Main Line Class (MLC)	N/A	$1,080.75	$1,080.75	N/A	N/A
Special Contract	N/A	N/A	$189,667.91	N/A	N/A
Power Station	N/A	N/A	$6,559.41	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.5083	$0.1843	$0.1843	N/A	N/A
Cooperative (CO-OP)	$0.4706	$0.1674	$0.1674	N/A	N/A
Main Line Class (MLC)	$0.1819	$0.2342	$0.2342	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0001	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0557	$0.0682	N/A	$0.0909	$0.1349
Large General Class (LGC)	$0.0553	$0.0325	N/A	$0.0909	$0.1349
High Volume Firm (HVF)	$0.0152	$0.0100	$0.0091	$0.0909	$0.1349
High Volume Firm (HVF) Refund	-$0.0168	-$0.0105			
Cooperative (CO-OP)	$0.0023	$0.0001	$0.0001	$0.0909	$0.1349
Main Line Class (MLC)	$0.0126	$0.0015	$0.0000	$0.0909	$0.1349
Main Line Class (MLC) Refund		-$0.0111			
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0183	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as descr bed above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after November 1, 2019

Approved by Board Order:
Effective from: November 1, 2019
Date Implemented: November 1, 2019

Supersedes Board Order: 16/19
Supersedes: February 1, 2019 Rates

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gss Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Interrupt ble Service	N/A	$1,035.29	$1,035.29	N/A	N/A
Mainline Interrupt ble (with firm delivery)	N/A	$1,080.75	$1,080.75	N/A	N/A
Monthly Demand Charge ($/m³ /month)					
Interrupt ble Service	$0.2710	$0.0895	$0.0895	N/A	N/A
Mainline Interrupt ble (with firm delivery)	$0.4169	$0.2342	$0.2342	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Interrupt ble Service	$0.0075	$0.0064	$0.0007	$0.0909	$0.1343
Interrupt ble Service Refund		-$0.0180			
Mainline Interrupt ble (with firm delivery)	-$0.0008	$0.0015	$0.0000	$0.0909	$0.1343

Alternate Supply Service:	
Gas Supply (Interruptible Sales and Mainline Interruptible)	Negotiated Cost of Gas
Delivery - Interruptible Class	$0.0093
Delivery - Mainline Interrup ible Class	$0.0092

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after November 1, 2019

REFERENCE:

IGU/CENTRA I-27

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the Heating Value Deferral Account charges.

QUESTION:

h) Please provide an estimate of the total 2018/19 heating value cost at a level of aggregation that can be made public.
i) Please discuss if the $2,519,879 balance is typical of the magnitude of balances in this account historically recovered over a one year period. If not, please explain what has contributed to a different balance.
j) Has Centra adjusted its forecast heat values to try to minimize future charges to this account? Please discuss why or why not.

RESPONSE:

h) The 2018/19 Heating Value Deferral Account balance including actual results for the months of November 2018 through March 2019 and applicable carrying costs through October 31, 2019 is forecast at a balance owing to Centra of [redacted], where the heating value ranged between 38.18 GJ/10^3m^3 to 38.34 GJ/10^3m^3 during the first five months of the 2018/19 Gas Year. 1d

i) Please see part l) to this question for the historical accumulations and dispositions of this account. As shown in that response, the largest prior balance requiring disposition was $1.6 million. The current balance of $2.5 million is larger than historically experienced largely due to the fact that the balance has accumulated over a three year timeframe, specifically the 2015/16 through 2017/18 Gas Years. Historically, deferral balances considerably larger than $2.5 million have routinely been collected in a single year.

j) Centra continues to embed a heating value of [redacted] GJ / 10^3m^3 as a reasonable forecast assumption. The graphic below illustrates the monthly average heating values 1d experienced over the eight-year period through October 2018, where the heating value ranged between 37.43 GJ/10^3m^3 to 38.49 GJ/10^3m^3.

[redacted] 1d

All of the aforementioned actual heating values fall within plus or minus 2% of the [redacted] GJ / 10^3m^3 utilized by Centra. In addition, it can be noted that the scale of the graphic provided 1d represents the range of acceptable heating values as found in TCPL's Transportation Tariff (between 36.00 GJ/10^3m^3 to 41.34 GJ/10^3m^3), helping to illustrate the modest range of actual experience realized by Centra customers in relation to said Tariff.

As discussed in the response to IGU/Centra I-27 f), the Heating Value Deferral Account functions in a reasonable and efficient manner to keep customers and the utility financially whole given the inevitable uncertainty and variability of the heating content of natural gas.

Please also see the response to PUB/CENTRA I-105c.

REFERENCE:

IGU/CENTRA I-27

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the Heating Value Deferral Account charges.

QUESTION:

k) Has Centra explored alternatives such as implementing rates based on energy instead of volumes to mitigate the need for this account? Why or why not?

l) Please provide a schedule showing the total amounts related to heating value variances collected or refunded to customers in each class by year for each of the last 10 years.

RESPONSE:

k) Centra has not undertaken a study related to a change to energy-based billing. A change from volumetric billing to energy-based billing for natural gas services would require significant changes to billing systems and customer care administrative processes and would require a significant amount of time and effort to communicate with customers to inform and educate them of such a change to their bills and rates.

l) The following table provides the total Heating Value Deferral Account collected or refunded to each customer class over the period 2006-2016.

Application	Heating Value Deferral Account - Gas Year	Total	SGS	LGS	HVF	ML	INT	SC	PS
2015/16 COG	2014/15 Heating Value (incl carrying costs)	[redacted]							
2014 Riders Appl.	2013/14 Heating Value (incl carrying costs)								
2015 Riders Appl.	2012/13 Heating Value (incl carrying costs)								
2013/14 GRA	2011/12 Heating Value (incl carrying costs)	(499,057)	(162,705)	(122,799)	(39,836)	(32,694)	(28,343)		
2013/14 GRA	2010/11 Heating Value (incl carrying costs)	(786,854)	(262,868)	(193,555)	(59,693)	(48,100)	(41,872)		
2011/12 COG	2009/10 Heating Value (incl carrying costs)	(922,298)	(311,027)	(225,497)	(67,184)	(67,808)	(56,842)		
2010/11 COG	2008/09 Heating Value (incl carrying costs)	(870,663)	(304,989)	(219,125)	(59,217)	(56,560)	(52,240)		
2009/10 GRA	2007/08 & 2008 Stub Heating Value (incl carrying costs	(1,611,401)	(512,013)	(369,220)	(122,341)	(102,836)	(104,177)		
2007/08 GRA	2006/07 Heating Value (incl carrying costs)	(1,186,526)	(409,896)	(289,121)	(85,658)	(57,800)	(76,948)		
2006/07 COG	2005/06 Heating Value (incl carrying costs)	(948,950)	(318,415)	(227,546)	(64,348)	(50,029)	(65,081)		
Total Heating Value Collection from customers/(Refund to customers)		(6,750,651)	(2,266,085)	(1,630,549)	(475,432)	(412,944)	(432,263)		

2d,1e

REFERENCE:

IGU/CENTRA I-15

PREAMBLE TO IR (IF ANY):

IGU requires some additional information on cost of service results.

QUESTION:

a) Please provide versions of IGU/CENTRA 1-15 Attachment 1 and Schedule 11.1.0 (pages 1 and 2) for each of the following scenarios:
   i. Assuming Centra targeted revenue to cost ratios at proposed non-gas rates (as shown at row 61 of IGU/CENTRA I-15 Attachment 1) of between 90% to 110%.
   ii. Assuming Centra targeted revenue to cost ratios at proposed non-gas rates (as shown at row 61 of IGU/CENTRA I-15 Attachment 1) of between 95% to 105%.
   iii. Assuming Centra targeted revenue to cost ratios at proposed non-gas rates (as shown at row 61 of IGU/CENTRA I-15 Attachment 1) of between 97% to 103%.
   iv. Assuming Centra did not make any adjustments to rates to rebalance RCC ratios across customer classes in the current application.
   v. Assuming Centra excluded the Special Contract Class from any cost allocations related to the Winnipeg Northwest Project (both Phase I and Phase II)
   vi. Assuming Centra excluded both the Special Contract Class and T-Service customers from any cost allocations related to the Winnipeg Northwest Project (both Phase I and Phase II).
   vii. Assuming Centra used the 2013/14 Transmission classification ratios as shown in the response to IGU/CENTRA I – 12 instead of the proposed 2019/20 Transmission classification ratios.

b) Please provide:
   i. a reference and an extract from the document that supports Centra's statement at page 15 of Attachment 11 to the Application that "Using load factor as the basis to weight peak and average appears to be consistent with an approach stated by the National Association of Regulatory Utility Commissioners but its origins in Manitoba are unknown and likely are due to be reviewed."

ii. An update on whether Centra has reviewed this issue and any conclusions or modifications that have been made to Centra's cost of service methods as a result.

c) Please discuss how Centra's cost of service study separates T-service customers from Sales Service customers for both the HVF and MLC classes.

d) Has Centra considered separating T-service customers into distinct customer classes for cost allocation purposes (essentially two classes for each HVF and MLC)? Please explain why or why not.

RESPONSE:

a) Response to part i), ii), iii) and iv):

Centra's cost allocation model produces ratios that are set at unity; therefore, the requested analysis cannot be performed. For additional context, please see the response to CAC/Centra I -19 b).

Response to part v):

Similar to above, the requested analysis cannot be performed but information responsive to this request can be found in PUB/Centra II-54

Response to part vi):

Please refer to parts c) and d) below.

Response to part vii):

The transmission classification ratios changed due to the plant additions in the period between 2013/14 GRA and the current application. As such, providing a scenario based on the 2013/14 transmission classification ratios would not provide a feasible analysis.

b)

i. Attachment 11 to the PUB Completeness Review filed on December 11, 2018 is "Manitoba Hydro's Response to the Cost of Service Methods Review by Christensen Associates". Centra's quotation in the question above relates to the application of load factor to the weighting of capacity allocation in the Peak and Average Method.

Centra's statement refers to information found on pages 81 and 82 from the NARUC Electric Utility Cost Allocation Manual, which are filed as an attachment to this response, regarding the "Average and Excess Allocation Method" which utilizes system load factor in its methodology. Centra notes that Peak and Average is a similar method to Average and Excess in that they both utilize system load factor in their respective methodologies.

ii. Centra has not undertaken further review of the matter to date.

c) and d)

Centra's cost allocation study was designed to provide the required level of cost separation and transparency to support the offering of unbundled natural gas supply options for its customers as the natural gas utility industry evolved in the 1990's. The cost allocation study categorizes costs into various functions, then classifies those costs and allocates them to the appropriate customer classes.

The differences between the HVF and Mainline customer classes and the various supply options that may be available to customers in that class (Sales Service (either system supplied or marketer supplied by way of WTS) or Transportation Service) are discussed below.

HVF class customers are firm service customers that are served from the distribution system and consume more than 680,000 cubic metres per year. Mainline class customers are firm service customers that consume more than 680,000 cubic metres per year and are served directly from the Centra transmission system.

The cost distinction between a Sales Service customer and a Transportation Service customer is accomplished by the functionalization of costs in Centra's cost allocation study, as described below.

The cost allocation study functionalizes costs into 6 separate categories. There are three upstream cost functions, Production, Pipeline and Storage, to address all of the costs incurred upstream of Centra's primary gate stations. There are three downstream cost functions, Transmission, Distribution and On-Site, to address all of the costs incurred on Centra’s own facilities in Manitoba.

The following example discusses a HVF customer that may choose from either Sales Service, system supplied by Centra, marketer supplied Sales Service through Western Transportation Service or Transportation Service.

The HVF customer choosing Sales Service using Centra’s system supply will be responsible for its share of costs from all six functions. Production-related costs are recovered through Centra’s Primary and Supplemental Gas charges and through UFG recoveries in the “Distribution to Customers” charge, and the upstream Pipeline and Storage function costs ultimately are recovered through the “Transportation to Centra” charges on the rate schedule. The HVF customer is served from the distribution system and is also responsible for a share of the Transmission, Distribution and On-Site costs, which are all downstream costs of the utility.

If that customer chooses to obtain Primary Gas from a gas marketer, the customer will not be responsible for Centra’s Primary Gas costs as their supplies are being acquired by the customer from a gas marketer. However, the marketer’s gas will be moved from supply source to the Manitoba market by way of Centra’s upstream storage and transportation assets. This is a service known as Western Transportation Service or WTS. As such, the customer is still responsible for a portion of Production costs related to Supplemental Gas and UFG, and for costs in the upstream Pipeline and Storage functions. This customer is similarly responsible for its share of the downstream costs (Transmission, Distribution and On-Site) on the Centra system.

A Transportation Service customer is responsible for acquiring its own natural gas commodity, and contracting for its own pipeline transportation and storage requirements sufficient to deliver the customers gas supplies to the interconnection between TCPL and the Centra system. A HVF Transportation Service customer will be charged for costs associated with the downstream functions (Transmission, Distribution and On-Site) but will not be charged for the upstream cost functions, except for the appropriate recovery of UFG costs, which are recovered in the Distribution to Customer charge.

Mainline class customers are served directly from Centra's downstream transmission system and are responsible for their respective share of both Transmission and On-Site related costs. As these customers are not utilizing the distribution system they are not responsible for costs that are functionalized as Distribution-related in Centra's cost allocation study.

There is no need to create a separate sub-class in either HVF or Mainline to distinguish between Sales Service or Transportation Service customers, as the costs attributable to either Sales Service or Transportation Service are clearly separated in the cost allocation study and are recovered in the appropriate rate charges on Centra's rate schedules.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

customer's average monthly contribution to the sum of the average monthly maximum demands of all customers.

As with the NCP method, data for individual customers such as municipal or co-operative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-6 for sample application of monthly average NCP allocation methodology.

TABLE 5-6

EXAMPLE OF MONTHLY AVERAGE NCP DEMAND ALLOCATION

Customer group NCP demand total(MW)	4778
System NCP demand total*	150347
Customer group monthly average NCP demand ratio	.03178

* Assuming a coincidence factor of .95 for the system, NCP for system CP monthly demands as shown in Table 5-1 would total 150347 MW.

6. Average and Excess Allocation Method

In contrast to the various peak demand allocation methods which assign costs based entirely on peak demand responsibility, under the average and excess demand allocation method (A&E) transmission costs are divided into two parts for allocation purposes on both demand and energy based on the system load factor (the ratio of the average load over a designated period to the peak demand occurring in that period). As such, the A&E method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases. This theory implies that a utility's capacity serves a dual function -- while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. Use of the A&E method for allocating transmission costs is typically employed for consistency when production costs are allocated on the same basis.

Because the A&E method does not recognize the coincident peak contribution of a customer group's load, the data necessary to perform the calculation is limited to the energy consumption and maximum (non-coincident) demand for a given period.

The first half of the formula, the "average" component representing the customer group's average energy consumption, allocates transmission costs on an energy use or average demand basis. The second half of the formula, the "excess" component is derived from the difference between the customer group's maximum non-coincident peak demand and the "average" demand component. The A&E method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor
A = customer group's energy requirements
B = total system energy requirements
C = customer group's "excess" demand responsibility
E = sum of all customer groups' "excess" demand responsibility

Implementation problems associated with the A&E method are inherent in the complexity of the computation. Additional complications may arise in an attempt to recognize that demand meter readings are not taken on a consistent basis, e.g., a large bulk power customer may reflect a greater degree of diversity as compared to a smaller low voltage distribution customer with little or no diversity. See Table 5-7 for sample application of average and excess allocation methodology.

TABLE 5-7

EXAMPLE OF AVERAGE AND EXCESS DEMAND ALLOCATION

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor = $\frac{\text{average load for year}}{\text{peak load for year}}$

$$= \frac{\dfrac{70470 \text{ million KWH (Table 5-1)}}{8784 \text{ hrs/yr}}}{15{,}050{,}000 \text{ KW (Table 5-1)}} = 53.3\%$$

A = customer group's energy requirements = 2449 million KWH assuming monthly load factor of 70%
B = total system energy requirements = 70,470 million KWH
(1-L) = 46.5%
C = customer group's "excess" demand responsibility
= 520 MW (Table 5-1) - $\frac{\text{2449 million KWH}}{\text{8784 hrs in 1988}}$ = 241 MW
E = 15842 MW (Table 5-1 CP demand for system at .95 coincidence factor) - $\frac{\text{70470 million KWH}}{\text{8784 hrs in 1988}}$
= 7819 MW

Therefore: $D = (53.3\%) \dfrac{2449 \times 10^6}{70{,}470 \times 10^6} + (46.7\%) \dfrac{241 \text{ MW}}{7819 \text{ MW}} = .032917$

REFERENCE:

IGU/CENTRA I-12 and IGU/CENTRA I-13

PREAMBLE TO IR (IF ANY):

IGU requires some additional information on cost of service methods.

QUESTION:

a) Please explain the reasons Transmission Classification ratios have changed from a total of 44.8% to demand in 2013/14 to 53.2% to demand in 2019/20 as shown in the response to IGU/CENTRA I-12 a) and c). In particular, please discuss how much of the change is due to:

    i. Changes in Centra's ratebase.
    ii. Changes in customer consumption volumes.
    iii. Changes in assumptions about customer load factors.
    iv. Any other changes Centra can identify.

b) Please provide a version of Figure 10.3 from page 11 of 14 from Tab 10 of the Application that breaks out the total increase or decrease in Non-Gas costs from 2013/14 to 2019/20 due to each of the following factors:

    i. Discontinuing funding the Furnace Replacement Program
    ii. Changes to participation in other DSM programs
    iii. Changes in the relative proportion of rate base that is transmission-related versus distribution-related
    iv. Other revenue requirement changes
    v. Changes in forecast usage on the peak day
    vi. Other changes in forecast demand levels
    vii. Any other changes (please specify the nature of these changes)

RESPONSE:

a) The shift in the Transmission function classification of Costs to Demand from Energy is entirely due to the change in rate base as shown in the following table.

Rate Base Functionalized to Transmission		Total	Demand	Energy
2019/20 TY	Total Rate Base	141,638,863	86,785,465	54,853,398
2019/20 TY	% of Rate Base		61.3%	38.7%
2013/14 TY	Total Rate Base	85,929,744	37,396,377	48,533,367
2013/14 TY	% of Rate Base		43.5%	56.5%

The shift is due to the large increase in transmission plant since the last GRA, which is classified as demand compared to a lesser increase in an investment in DSM, which is classified as energy.

b) The following table (shown in $000sreconciles Non-Gas costs from 2013/14 Approved to the 2019/20 test year, which was updated in Figure 8 of the Supplement, identifying the main drivers of the changes impacting each rate class:

2019/20 TY	1	2	3	4	5	6	7	8	9	10	11	12	13
Change in Non-Gas costs	2013/14			Peak Day	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY	2019/20 TY
	Approved	FRP	DSM	Changes	Oth. Rev. Chgs	O&A Reduce.	O&A shift	Depr Exp Red.	Depr Exp shift	Tax etc. Inc.	Tax etc. shift	Other Chgs.	Proposed
SGS	110,336	(3,800)	1,593	(81)	680	(6,317)	(1,878)	(795)	(1,052)	4,146	(710)	512	102,633
LGS	29,073		1,332	432	2	(1,270)	779	(211)	681	1,397	509	(268)	32,456
High Volume Firm	5,184		154	61	- 5	(281)	709	(33)	251	240	561	(17)	6,824
Co-op	8		-	(0)	0	(1)	0	(0)	0	0	0	0	8
Mainline	1,816		(188)	(86)	- 2	(87)	273	(9)	95	73	72	101	2,058
Special Contract	1,385		-	(134)	- 2	(72)	251	0	158	92	409	159	2,247
Power Stations	256		-	(128)	0	(13)	(16)	2	(30)	21	(62)	128	158
Interruptible	2,090		(144)	(62)	5	(106)	(432)	(11)	(131)	99	(594)	57	770
Primary Gas	956	[redacted]											
Supplemental Firm	160	[redacted]											
Supplemental Interruptible	14	[redacted]											
Fixed Rate Primary Gas	242			-	1	(15)	(94)	(0)	(7)	1	(6)	(100)	21
Total Cost of Service	151,520	(3,800)	2,747	(0)	676	(8,250)	(0)	(1,060)	0	6,114	(0)	572	148,519

1e

Column 2

Shows the impact of the Furnace Replacement Program ("FRP") discontinuance.

Column 3

Shows the impact of changes in participation of DSM programs by class.

Column 4

Shows the impact of the change in the class by class share of Centra's coincident peak day.

Column 5

Shows the impact of changes to Other Revenue.

Column 6

Operating and Administrative ("O&A") Program costs declined from the 2013/14 Approved Test year level by $8.25 million in the 2019/20 Test Year, $68.8 million in 2013/14 vs. $60.5 million in 2019/20. Column 6 shows the class by class impact of an $8.25 million reduction.

Column 7

O&A Program Costs will shift from class to class compared to a previous test year due to changes to:

- Rate base, as some elements of rate base are used to allocate some O&A programs such as Distribution Maintenance;
- Load forecast changes in volumes, customer numbers and share of Centra's coincident peak day; and
- Budgeted spending on program costs from year to year.

Column 8

Depreciation Expense, Amortization of CIAC and Depreciation on Common Assets has decreased by a total of $1.06 million in the 2019/20 Test Year. Column 8 shows the class by class impact of the $1.06 million reduction.

Column 9

Depreciation Expense, Amortization of CIAC and Depreciation on Common Assets will shift from class to class compared to a previous test year primarily due to changes to:

- Rate base, changes reflecting the increase in transmission investment; and
- Load Forecast changes in volumes, customer numbers and share of Centra's coincident peak day.

Columns 10 & 11

Property & Other Taxes, Finance Expense, Corporate Allocation and Net Income are almost exclusively functionalized, classified and allocated by rate base. The 2019/20 Test Year forecast reflects a $6.114 million increase over 2013/14 Approved Test Year costs. Column 10 shows the class by class impact of the $6.114 million increase. Column 11 shows the class to class shift of these costs due to:

- Rate base changes reflecting the increase in transmission investment; and
- Load Forecast changes in volumes, customer numbers and share of Centra's coincident peak day.

Column 12

Reconciles changes to non-gas costs between the 2013/14 Approved Test Year and the 2019/20 Test Year that have not been discussed elsewhere in this response.

REFERENCE:

IGU/CENTRA I-12 and IGU/CENTRA I-13

PREAMBLE TO IR (IF ANY):

IGU requires some additional information on cost of service methods.

QUESTION:

c) Centra states in IGU/CENTRA I-13 d) that the input data used to calculate the peak and average allocator has been updated to reflect the Natural Gas Volume forecast. Are changes to the input data based solely on actual changes in actual customer consumption and usage data? If not, please explain any other assumptions or changes that influence the Natural Gas Volume forecast and the calculation of the peak and average allocator.

d) Please discuss how class load factors and class coincidence factors are used in the cost of service study and in particular:
   i. Are they calculated using actual metered data.
   ii. Do they involve any assumptions, estimates or industry standard ratios. If so, please identify and describe these and whether they have changed since the 2013/14 GRA.

RESPONSE:

c) The updated input information used to calculate the peak and average allocators are based on the additional year of actual customer and usage information, and are coupled with the underlying assumptions and methodologies that create the 2018 Natural Gas Volume Forecast as described in Appendix 7.6 of the application.

d) The methodology utilized to calculate the class load factors and coincidence factors has remained consistent since the 2013/14 GRA and are calculated using actual metered data. The class load factors and coincidence factors calculated using actual data is applied to the volume forecast within each rate class for the test year.

REFERENCE:

IGU/CENTRA I-14a

PREAMBLE TO IR (IF ANY):

IGU requires a response to this question that can be made public without redaction.

QUESTION:

Please provide a narrative discussion of the information provided in the response that can be made public without redaction.

RESPONSE:

As per PUB's direction in Order 77/19, Centra has provided IGU with an un-redacted copy of IGU/CENTRA I-14a.

REFERENCE:

IGU/CGM I-8 (k), IGU/CGM I-7 (a)

PREAMBLE TO IR (IF ANY):

Centra has not answered the original question to IGU/CGM 1-8 (k) directly in regards to setting fair and equitable rates. In answer to IGU/CGM I-7 (a): Centra's response below seems to contradict the results of the rate setting methodology used.

"Existing natural gas customers should not be unduly burdened by the extension of natural gas service or addition of new customers. Centra ensures that the revenues from new customers attaching to the system are sufficient to offset (or pay) the cost of constructing dedicated new facilities required to provide service to them."

The project justification for the Winnipeg Northwest Upgrade Phase 2 project indicates clearly it is in part due to anticipated capacity increases over the next 20 years.

QUESTION:

a) In Centra's answer to IGU/CGM 1-8 (k) they refer to answer CAC/Centra I-19a. This answer gives an example of a T service customer that had rates decreased a few years ago and then increased as part of this GRA. Please confirm that this example is not the Special Contract customer.
b) Please explain how an increase of 60% is not unduly burdening one customer while other customers on the system are seeing rate decreases?
c) How does Centra reconcile their answer to IGU/CGM 1-7 (a) with that provided to IGU/CGM 1-8 (k)?

RESPONSE:

a) Confirmed.

b) There are a range of customer impacts by customer class and by type of service in this rate application, which is the result of allocating the revenue requirement amongst classes. This reapportionment of the revenue requirement results in cost based rates that are set at a revenue-to-cost ratio of 1.0 for each customer class.

Centra recognizes that the proposed increase for the Special Contract class is significant, but given the size of the load for this customer class, the overall decline in commodity costs in the natural gas market and the recent decreases to firm transportation ("FT") tolls on TCPL's Mainline, which are not reflected in the rates charged by Centra to this customer class, it is unable to determine whether the overall landed cost of gas to the Special Contract class represents an undue burden.

c) Centra notes that the question in IGU/CENTRA I-7a asked for a copy of Centra's Facility Extension Guidelines, including customer contribution calculation methodologies, whereas IGU/CENTRA I-8k asked if Centra considered a 60% increase fair, in accordance with its fairness mandate outlined in the GRA, Tab 2, page 2 or Tab 10 Section 10.1.

In terms of the fairness of a proposed 60% increase, Centra notes that rates may be considered to be fair if they recover the cost of serving that customer class. Rates in this Application have been calculated at a revenue-to-cost ratio of 1.0 and therefore would be the level required to recover the costs of serving each customer class.

Please also see Centra's response IGU/CENTRA II-16d.

REFERENCE:

IGU/CGM I-8 (k), IGU/CGM I-7 (a)

PREAMBLE TO IR (IF ANY):

Centra has not answered the original question to IGU/CGM 1-8 (k) directly in regards to setting fair and equitable rates. In answer to IGU/CGM I-7 (a): Centra's response below seems to contradict the results of the rate setting methodology used.

"Existing natural gas customers should not be unduly burdened by the extension of natural gas service or addition of new customers. Centra ensures that the revenues from new customers attaching to the system are sufficient to offset (or pay) the cost of constructing dedicated new facilities required to provide service to them."

The project justification for the Winnipeg Northwest Upgrade Phase 2 project indicates clearly it is in part due to anticipated capacity increases over the next 20 years.

QUESTION:

d) Please explain how "Centra ensures that revenues from new customers attaching to the system are sufficient to offset (or pay) the cost of construction" with respect to the costs of the Winnipeg Northwest Upgrade Phase 2 project.

RESPONSE:

Centra evaluates and performs capital projects through two business streams: New Business and System Betterment.

The quote included in the preamble is taken from the response to a question about Centra's guidelines for customer requested facility extensions and therefore relates to the evaluation process associated with New Business projects. New Business projects are undertaken in response to specific customer requests for either a new service connection or a significant load increase at an existing location that requires the construction of additional facilities. These projects may include an identified customer such as a large industrial load, or a group of customers, such as found in residential sub-divisions.

System Betterment projects, such as the Winnipeg Northwest Project, are performed to maintain system reliability and safety as well as support the continued operation of the existing system. System Betterment projects are performed to address identified aggregate capacity issues or identified non-compliances with CSA Z662 Oil and Gas Pipeline Systems such as insufficient pipeline cover or changes to Class location.

Growth of an existing system occurs over time due to the addition of new customers through service installations or small new projects or by existing customers increasing gas consumption through the addition of new equipment. While those customers may have been required to make a contribution in aid of construction towards their distribution main and service line costs, at the time there may have been adequate capacity upstream of their connection to serve their new load. However, over time, the accumulation of this normal load growth may result in the acceptable limits to system capacity being reached and a System Betterment project may be initiated to provide additional capacity.

A System Betterment capacity project approval process follows the Centra project approval process based on the estimated capital cost. Customer contributions are not collected for system betterment projects.

REFERENCE:

IGU/CGM I-8 (k), IGU/CGM I-7 (a)

PREAMBLE TO IR (IF ANY):

Centra has not answered the original question to IGU/CGM 1-8 (k) directly in regards to setting fair and equitable rates. In answer to IGU/CGM I-7 (a): Centra's response below seems to contradict the results of the rate setting methodology used.

"Existing natural gas customers should not be unduly burdened by the extension of natural gas service or addition of new customers. Centra ensures that the revenues from new customers attaching to the system are sufficient to offset (or pay) the cost of constructing dedicated new facilities required to provide service to them."

The project justification for the Winnipeg Northwest Upgrade Phase 2 project indicates clearly it is in part due to anticipated capacity increases over the next 20 years.

QUESTION:

e) Please explain how Centra ensures revenues from new customers are sufficient to offset costs as it relates to the costs of the Winnipeg Northwest Upgrade Phase 2 project and the large proposed base rate increases for T-Service customers.

RESPONSE:

e) The Winnipeg Northwest Upgrade was a system betterment project not a facility extension to serve a new customer. Unlike new business projects, to which the quote in the preamble pertains, system betterment projects do not have new customers or new revenues associated with them, rather they are undertaken to ensure the integrity of the system as a whole.

   To clarify the premise in the final part of the question, T-Service is a service option and not a rate class. Accordingly the impacts on T-Service customers vary based on their rate class. As is demonstrated in PUB/Centra II-54, the majority of the revenue requirement impact of the Winnipeg Northwest Upgrade is being borne by Small General Service ("SGS") and Large General Service ("LGS") customers.

The increase in base rates of the majority of T-Service customers is occurring due to the unwinding of the rate reversion that occurred on August 1, 2017, that resulted in significant rate decreases for certain customers.

REFERENCE:

IGU/CENTRA I-8 (b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an estimate of the portion of the costs outlined in IGU/CENTRA I-8 (b) (ii) that would be borne by industrial customers. Please state any assumptions used in preparing the analysis.

RESPONSE:

Please refer to the attachment to PUB/CENTRA II-54.

REFERENCE:

IGU/CENTRA I-8 (b)

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a table in a similar format to the response to IGU/CENTRA I-8 (b) (ii) that shows the forecast revenue requirement changes due to all currently planned transmission capital projects.

RESPONSE:

b) The revenue requirement of all planned transmission capital additions has been estimated and is provided in the following table. Note that this type of analysis is limited by virtue of treating individual projects on an incremental cost basis. While costs such as depreciation expense may be estimated and may be directly attributable to an asset, other costs such as finance expense, capital taxes and benefits are not readily estimated on an incremental basis. In addition, the following table does not include operating, administrative & maintenance costs specific to these capital additions as these costs are not specifically tracked on a per transmission asset basis. As indicated in the response to IGU/CENTRA I-8h, costs for general maintenance to these assets include:

- Steel valve maintenance;
- Cathodic protection system monitoring;
- Buried plant locate services; and,
- Click Before You Dig/Safety Watch.

Estimated Cumulative Incremental Revenue Requirement from Planned Transmission Projects (CEF18)
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Finance Expense	0.2	0.7	1.0	1.3	1.6	1.8	1.9	2.1	2.4	2.6
Depreciation	0.1	0.7	1.2	1.7	1.9	2.0	1.6	1.4	1.1	1.1
Capital Tax	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
	0.3	1.5	2.3	3.1	3.7	4.0	3.8	3.7	3.7	3.9

Centra notes that CGM18 includes these planned transmission projects and therefore the indicative rate increases provide sufficient revenue requirement to cover all planned capital expenditures.

REFERENCE:

IGU/CENTRA I-8 (b)

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide an estimate of the portion of the revenue requirement changes in part (a) that would be borne by industrial customers and the approximate average annual rate increases to non-gas rates that would be required to address these increases.
d) In Centra's view, given the current cost of service methodology, are these spending forecasts, allocations to T-Service customers and rate increases sustainable in the future? Please explain.

RESPONSE:

c) and d)

Centra is unclear as to whether this question intended to refer to part a) or part b).

If the intent was part a), please see the response to PUB/CENTRA II-54 for details with respect to the rate class responsibility for the incremental revenue requirement stemming from the Winnipeg North-West project.

If the intent was part b), Centra is unable to determine rate class responsibility for the additional transmission investments included in the 10 year forecast, as not all cost allocation study inputs are available beyond the test year.

A one-time general revenue increase of 1.0% would increase revenues by approximately $3 million per year, which is estimated to yield approximately $30 million in revenues over the forecast period, sufficient to address the revenue requirement associated with the planned transmission investments identified in part b). Without making a series of assumptions related to cost allocation study inputs, Centra is unable to judge the sustainability of projected rate impacts to individual customer classes, however, provided distribution assets grow at approximately this same pace as these transmission assets those impacts could be expected to be minimal and would be sustainable.

REFERENCE:

PUB/CENTRA I-73

PREAMBLE TO IR (IF ANY):

QUESTION:

Centra states at Page 60 of the Attachment to PUB/CENTRA I-73 that the Winnipeg Northwest Upgrade Phase 2 project was justified in part to provide transmission capacity to serve the growth just north of Winnipeg for the next 20 years. Please discuss:

i. What customer classes are driving these growth projections.
ii. Are there any new industrial customer loads included in those growth projections? If so, please explain on what basis Centra included such customers in the forecast.
iii. Please explain whether loads related to CentrePort are included in those growth forecasts and on what basis Centra has developed any such forecasts.

RESPONSE:

Regardless of which customer classes drive growth projections, as part of an integrated system, once additional capacity is installed it becomes available for customers in any class to utilize.

i. Large Commercial, Small Commercial and Residential are the customer classes driving the growth projections.
ii. No defined industrial customer loads were identified or are included in the growth projections. An annual growth projection of 1.1% of peak load was used for this planning study and report. The total peak load includes industrial customers.
iii. Loads associated with Centreport customers are not included in the growth forecasts. Initial development of Centreport is expected in areas that are supplied by other portions of the Centra distribution system. Future development may be supplied from the Winnipeg Northwest Phase 2 system but this was not included in any growth forecasts.

REFERENCE:

PUB/CENTRA I-90 Winnipeg Northwest Upgrade Phase 2 Project

PREAMBLE TO IR (IF ANY):

QUESTION:

a) It appears the highest cost option (option 4) was chosen to execute. What working papers or documentation does Centra have to justify the economics for the increased marginal spend? Please provide.
b) The alternative "do nothing" approach per section 4 has a projected cost of $21MM, $10MM less than the option chosen. Is it correct to say from a sustaining standpoint, this option may have been acceptable, but it did not address future capacity improvements?

RESPONSE:

a) The planning reports and Capital Project Justifications ("CPJ"s) and Addendums related to the Winnipeg Northwest Upgrade Phase 2 Project have been provided in the response to PUB/Centra I-90 and in the response to PUB/Centra I-73, respectively.

b) From a sustaining standpoint, it would not be correct to say, "the "do nothing" option may have been acceptable, as it did not address future capacity improvements."

The "do nothing" option would not provide redundant capacity and network operational balance for the protection of the multiple feeds into all of the City of Winnipeg. The $21 million referenced would only cover looping to sustain capacity north of Winnipeg. The "do nothing" option would not address balancing of loads on the primary stations in Winnipeg, provide redundant supplies to areas north of Winnipeg, provide redundant capacity to the feeds into Winnipeg, provide operational flexibility to the feeds into Winnipeg or avoid extensive looping of the transmission systems north of Winnipeg; all of which provide significant and further benefit to Centra's system.

REFERENCE:

IGU/CENTRA I-5a-b: Clarification of In-Service Dates

PREAMBLE TO IR (IF ANY):

“There is generally no prioritization of Capital verses operations and maintenance spending”.

QUESTION:

a) What is Centra’s definition of an “in-service date” given the Winnipeg Northwest Upgrade phase 2 project was indicated as in service in 2017? Does this mean it is fully commissioned and in use?
b) If not fully commissioned, can Centra please break down what sections of the project are in service and what if any areas are not yet in use?

RESPONSE:

a) The “in-service date” was January 23, 2017 which is the date the pipeline and associated facilities were commissioned and fully energized with natural gas.

b) All sections were considered fully commissioned and in use as of January 23, 2017.

REFERENCE:

PUB/CENTRA I-66(b)

PREAMBLE TO IR (IF ANY):

"There is generally no prioritization of Capital verses operations and maintenance spending".

QUESTION:

a) In light of the above disclosure, how does Centra determine which projects to work on first?
b) Please explain how Centra can assess risk without any specific prioritization?

RESPONSE:

a) The question in PUB IR I-66 b) was:

   "Explain how Centra prioritizes spending between departments, asset types and capital verses operations and maintenance".

   The response quoted above indicates no prioritization between capital and operations and maintenance activities, and does not relate to the prioritization of capital projects. Centra has different departments with different functional responsibilities. Customer Service Operations and Gas Apparatus Maintenance and Control Departments have a greater focus on operations and maintenance activities with some minor capital spending while Gas Engineering & Construction and Customer Metering & Electrical Codes have an almost exclusive focus on capital projects.

   Capital projects are almost exclusively performed by Gas Engineering and Construction with installation by contractor resources and specialist skills provided by internal operating groups.

b) Centra does prioritize projects just not across functional groups. For example, operation and maintenance groups prioritize their work programs to meet their yearly defined goals and capital groups prioritize their projects. In the past, capital groups have prioritized projects based on the defined project need and the availability of resources to execute the project. Centra assesses risk on the defined capital projects or programs. Centra is transitioning to the use of the Corporate Value Framework as a means to further assist in prioritizing capital projects and programs across departments and corporate and operating groups. The Corporate Value Framework is provided as the response to PUB/Centra I-67.

REFERENCE:

IGU/Centra I-19 (d)

PREAMBLE TO IR (IF ANY):

Centra indicates that the reliability in the gas delivery system is 99.99993% and that any outages were mainly the result of external factors.

QUESTION:

Why is Centra proposing, approving and executing projects for redundancy (two sets of gas lines for example) given the high availability factor above?

RESPONSE:

Given Manitoba's extreme climate, and the reliance of Centra's customers on natural gas for space heating, Centra seeks to avoid and/or mitigate the impact of prolonged outages. The system reliability is very high but past performance is not necessarily an indicator of future performance. Centra has an aging infrastructure with many of the transmission pressure pipelines in the system 50 or more years old. Pipeline condition is considered to be good but condition information on all assets is not available. The greatest risk to pipelines remains a third party damage which can happen at any time to any pipeline. Centra has pipelines where specific portions such as water crossings, rail crossings or major highway crossings, can take days to weeks to repair and return the pipeline to operation. For example, in 2011 during a major spring flood event, Centra experienced a river bank failure at a pipeline crossing that left the pipeline exposed to the floodwaters. A nearby bridge was used for the installation of a temporary main to permit the main in the river to be abandoned before the line failed. While no customers were affected, the replacement river crossing took 2 months to complete. Unfortunately, the ability to install temporary crossings is not always available.

Unlike an electrical outage where service is automatically restored once the power comes on, there is a lengthy process to relight and safely return a gas customer to service. A gas service person must visit each customer, provide a relight as necessary and inspect for a safe return to operation. The January 2014 Otterburne outage required approximately 44 hours to return the 3,660 affected customers to service once the gas was returned to service.

There are costs to Centra for relighting customers and providing support during an outage, and there are costs to the natural gas customers to provide an alternate source of heat, seek safe accommodations for vulnerable people and potential losses for businesses who cannot continue normal operation.

Centra recognizes the importance of the availability of natural gas to all customers and continues to perform resiliency planning to determine how gas customers in the system would be supported in the event of a loss of a gas supply. This planning includes the determination on where trucked compressed natural gas (“CNG”) can be used or where the community or system size is too large to support with trucked CNG and a second pipeline supply may be required. Installation of a second pipeline supply is being evaluated for larger communities only and is not expected to be frequently used.

REFERENCE:

PUB/CENTRA I-62

PREAMBLE TO IR (IF ANY):

Additional Project Scope of 3.0km of 8” pipe as part of the Winnipeg Northwest Upgrade Phase 2 Project.

QUESTION:

a) There is reference that this additional item in the project was for an industrial facility. What industrial facility was the additional scope for? What customer class has this industrial facility been included in for the forecast period? Please provide an explanation for the increased revenue to justify the corresponding cost increase.
b) Why was this scope change not handled as a separate project with a separate justification?

RESPONSE:

a) The response to PUB/CENTRA I-62 is referencing key variances per fiscal year. The reference to 3.0 km of 8” pipe has no relation to the Winnipeg Northwest Phase 2 Project. It was a standalone project contributing to the over expenditure in fiscal year 2016/17.

b) The standalone project had its own project justification. This project is included in Centra’s report on Main Extensions over 500 metres in Attachment 13.2 of the Application (MER 2015-00120).

REFERENCE:

IGU/CENTRA I-12a-d

PREAMBLE TO IR (IF ANY):

Centra provides a comparison for 2013/14 for test year for classifying transmission costs and the 2015/16 test year for classifying storage costs.

QUESTION:

a) Provide cost allocation data of these costs from ratebase/revenue requirement to classification for all available cost allocation test years (2013/14, 2015/16 and 2018/19).
b) Comment on any changes to methodologies in either functionalization or classification and how it impacts individual rate classes as a result.
c) Comment on any changes to underlying input data including capital additions, retirements, load input calculation/assumption changes, etc. and how it impacts individual rate classes as a result.

RESPONSE:

a) Please see the attached schedule which provides further details on the classification of storage and transmission costs. Please note that 2015/16 was a Non-Primary Gas cost hearing, therefore no rate base details are available.

b) There have been no changes in functionalization or classification of rate base costs. For additional information, please refer to PUB/CENTRA I-134.

c) For the Storage function the continued reduction in the commodity cost of gas is reflected in the reduced value of Gas in Storage (as part of Rate Base) in the 2019/20 Test Year compared to the 2013/14 Approved Test Year. The result is a reduced share of rate base for the storage function which in turn attracts a reduced share of costs that use rate base as the main allocator such as finance expense and corporate allocation.

As the SGS and LGS classes use most of the Storage Gas in Inventory, they will benefit most by the reduced share of costs that use rate base as an allocator.

In the Transmission function the recent increases in Transmission Plant investment will increase the share of rate base functionalized to the Transmission function. As a result, Transmission plant forms a significantly higher portion of total Rate Base in the 2019/20 Test Year compared to 2013/14 Test Year. The increased transmission plant results in rate base allocated costs, such as finance expense and corporate allocation, also being allocated in the same manner to the transmission function. The result is that Transmission served customers will be allocated an increased share of costs such as finance expense and corporate allocation.

With respect to volume changes, the LGS class has continued to experience a growth in consumption in the past few years. The growth has resulted in a larger share of total system volumes and a larger share of Centra's coincident peak day, resulting in an increase in allocated costs. The HVF class has increased in both number of customers and volumes from prior years, which is the result of several customers migrating from the Interruptible class after the 2013/14 winter. The HVF class has had an increase in allocated costs roughly corresponding to the decrease in allocated costs to the INT class as a result of the migration.

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to IGU-II-24 a)

2019-06-09

Rate Base		Storage Costs Total	Storage Costs Demand	Storage Costs Energy	Transmission Costs Total	Transmission Costs Demand	Transmission Costs Energy
2013/14 TY	Intangible Plant				2,161,080	2,161,080	-
2013/14 TY	Transmission Plant				105,875,559	105,875,559	-
2013/14 TY	General Plant	89,649	74,638	15,011	1,036,240	1,035,555	685
2013/14 TY	Accumulated Depreciation	(59,405)	(49,458)	(9,947)	(31,347,366)	(31,346,957)	(409)
2013/14 TY	Contributions in Aid of Construction				(41,008,273)	(41,008,273)	-
2013/14 TY	Cash Working Capital	512,168	446,231	65,936	1,640,104	679,412	960,692
2013/14 TY	Gas in Storage	38,863,462	-	38,863,462	-		
2013/14 TY	Investment in DSM				47,572,399	-	47,572,399
2013/14 TY	Total Rate Base	39,405,874	471,411	38,934,462	85,929,744	37,396,377	48,533,367
2019/20 TY	Intangible Plant				2,726,008	2,726,008	-
2019/20 TY	Transmission Plant				171,941,305	171,941,305	-
2019/20 TY	General Plant	212,431	191,918	20,514	1,225,780	1,225,059	720
2019/20 TY	Accumulated Depreciation	(122,246)	(110,441)	(11,805)	(42,931,760)	(42,931,365)	(394)
2019/20 TY	Contributions in Aid of Construction				(47,617,231)	(47,617,231)	-
2019/20 TY	Cash Working Capital	618,294	565,487	52,807	2,159,917	866,716	1,293,201
2019/20 TY	Gas in Storage	33,138,755	-	33,138,755			
2019/20 TY	Investment in DSM				53,559,521	-	53,559,521
2019/20 TY	Investment in Regulatory Costs	47,985	43,352	4,634	253,798	253,643	155
2019/20 TY	Investment in Site Restoration				321,525	321,329	196
2019/20 TY	Total Rate Base	33,895,220	690,315	33,204,905	141,638,863	86,785,465	54,853,398

Revenue Requirement		Storage Costs Total	Storage Costs Demand	Storage Costs Energy	Transmission Costs Total	Transmission Costs Demand	Transmission Costs Energy
2013/14 TY	Cost of Gas	16,134,548	13,432,975	2,701,573	2,412,324	198,444	2,213,880
2013/14 TY	Other Income	(5,404)	(4,499)	(905)	(34,559)	(34,522)	(37)
2013/14 TY	Operating & Maintenance Expenses	624,066	519,572	104,494	3,991,058	3,986,761	4,296
2013/14 TY	Depreciation & Amortization	43,615	36,312	7,303	8,973,780	1,776,098	7,197,682
2013/14 TY	Capital & Other Taxes	551,632	12,606	539,026	3,039,798	2,369,359	670,440
2013/14 TY	Finance Expense	1,365,211	16,332	1,348,879	2,977,023	1,295,592	1,681,431
2013/14 TY	Corporate Allocation	966,806	11,566	955,240	2,108,249	917,504	1,190,745
2013/14 TY	Net Income	241,701	2,891	238,810	527,062	229,376	297,686
	Total Revenue Requirement	19,922,174	14,027,755	5,894,419	23,994,735	10,738,612	13,256,123

		Storage Costs	Transmission Costs	
2015/16 TY	Cost of Gas	[redacted]	[redacted]	1a
2019/20 TY	Cost of Gas			1a
2019/20 TY	Other Income			
2019/20 TY	Operating & Maintenance Expenses			
2019/20 TY	Depreciation & Amortization			1e
2019/20 TY	Capital & Other Taxes			
2019/20 TY	Finance Expense			
2019/20 TY	Corporate Allocation			
2019/20 TY	Net Income			
2019/20 TY	Total Revenue Requirement			1e

REFERENCE:

Postage Stamp Rates

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm:
   i. Whether or not special contract or T-service customers have ever paid customer contributions for assets to service their facilities directly.
   ii. If the response to part (i) is yes, please confirm whether or not any of these assets share physical characteristics with assets that have been functionalized as transmission assets and allocated to all customers in Centra's cost of service study.

b) Please provide an estimate at a level of aggregation that can be made public of:
   i. the percentage of total customer loads on the Manitoba system that were special contract and/or T-service at the time the PUB made its comments in Orders 158/86 and 142/89.
   ii. The percentage of total customer loads on the system that are special contract and/or T-service today.

RESPONSE:

a)

i. Some T-service customers have paid contributions in aid of construction to extend or upgrade natural gas service to their facilities. Customer contributions in aid of construction are calculated using the PUB approved natural gas feasibility test. The feasibility test is incremental in nature and captures costs and revenues over a 30 year time horizon.

ii. Regardless of whether or not a customer has made a contribution in aid of construction for the facilities that are required to serve it, those facilities will be placed in service and recorded in the appropriate asset class, based on their characteristics as shown in the attachment to the response to IGU/Centra I–4 a).

b)

i. The PUB issued Order 156/86 on December 18, 1986, prior to the full implementation of Transportation Service. Centra understands that there was one industrial customer that had entered into a Transportation Service agreement with Greater Winnipeg Gas at that time, but the percentage of total system load is not readily available.

Order 142/89 was issued on August 8, 1989. It is estimated that the combined percentage of Special Contract and Transportation Service volumes represented approximately 13% of system load.

ii. In the 2018/19 fiscal year, the combined percentage of Special Contract and Transportation Service volumes represented approximately [redacted] of the system load. 1d

REFERENCE:

Postage Stamp Rates

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Does the postage stamp rate making approach also apply to Centra's Power Stations customers? If not, why not.

RESPONSE:

Yes. The postage stamp principle is applied to all of Centra's customer classes including the Power Station class.

REFERENCE:

PUB/MH I-64 & IGU/MH I-8a-c

PREAMBLE TO IR (IF ANY):

Centra provides an overview of the types of approvals required depending on the proposed budget for capital projects.

For projects the size of the Winnipeg Northwest Project, approval is required by the Executive Committee.

QUESTION:

a) Please list who is on the Executive Committee, including who was on the committee at the time of approval for the Winnipeg Northwest Project (both phases).
b) Please confirm both project phases were reviewed and approved together. If not, explain why not.
c) Please provide all materials reviewed by the Executive Committee in its decision regarding the Winnipeg Northwest Project (Phase I & Phase II)
d) Please provide the timeline for review and the approvals that took place.
e) Were there any cost or project scope changes that occurred after approval was provided. If so what were they and were subsequent approvals required as a result of project cost/scope changes.

RESPONSE:

a) The Executive Committee at the time the Winnipeg Northwest project was approved was comprised of the President and Chief Executive Officer, the Vice-Presidents from the organizational units, and the Senior General Counsel/Corporate Secretary.

   The Winnipeg Northwest Projects (Phase I and Phase II) were approved based upon the management approval levels in place at the time of approval. The approval levels provided in PUB/CENTRA I-64 were put in place in conjunction with the implementation of the Corporate Portfolio Management ("CPM") project in 2017. From 2013 through to 2016, projects with a total cost greater than $50M required Executive Committee approval; projects with a total cost between $2M and $50M required approval by the Vice-President of the Corporate or Operating Group responsible for the investment.

b) The phases were not reviewed and approved together because the projects were required in order to meet different needs. Phase 1 made provision for the future Phase 2 but the potential timing of Phase 2 was not known when Phase 1 was being reviewed and approved. The Winnipeg Northwest Project Phase I was required to increase pressures in the St. Andrews area. This was accomplished by the addition of 4,630m of 12" steel transmission pressure ("TP") pipe, a new station, and a medium pressure polyethylene ("PE") pipe to tie into the existing distribution network. A 4" TP pipeline would have been adequate to supply the new station and increase pressures in the St. Andrews area. The only relation to Winnipeg Northwest Phase II was increasing the pipe size from the 4" TP Pipeline to 12" TP pipeline to permit this section to be compatible with Winnipeg Northwest Phase II.

c) The planning reports have been provided in the PUB/CENTRA I-90 response and the CPJs have been provided in attachment to PUB/CENTRA I-73 pages 35 to 82.

d) The Winnipeg Northwest Project – Phase I was approved for implementation in January, 2014 at a total cost of $3.1M and the Winnipeg Northwest Project – Phase II was approved for implementation in December, 2014 at a total cost of $31.1M. There were two subsequent addendums for the Phase I project, first in October 2015 reflecting a year deferral of the in-service date only, and second in February 2016 reflecting an increase to $4.3M and a further deferral of the in-service date. The Phase II project had one addendum in June 2016 reflecting a reduction in the total cost to $23.6M.

e) Yes, there were project scope and capital changes for both Phase I and Phase II of the Winnipeg Northwest Project. The major capital changes are reflected in the Phase I, Addendum 2 and the Phase II, Addendum 1 documents. Generally, as described in detail in Phase I, Addendum 2, additional costs were incurred primarily for materials, property and to address higher internal costs due to a longer than estimated project duration. The larger Phase II project attracted a large number of contractors and resulted in very competitive contractor bids and permitted the project cost to be reduced downward. Approval guidelines for cost or project scope changes followed Manitoba Hydro's policies in place at the time.

REFERENCE:

Cost of Service Study

PREAMBLE TO IR (IF ANY):

IGU requires additional information related to Centra's Cost of Service Study

QUESTION:

Please provide versions of each of Schedules 10.1.0 through 10.1.6 (7 schedules in total) for each of the following cost of service study scenarios:

i. Replacing the class Peak and Average allocators with class Coincident Design Day Demand allocators.
ii. Allocating costs in the cost of service model to the special contract class based on direct assignment of costs. Specifically, instead of allocating the cost of the total Centra transmission system to the Special Contract Class using the P&A allocator, the Special Contract Class would be directly assigned only the cost of the two transmission mains serving it (28km NPS 12 diameter and 21 km NPS 6 diameter pipeline).

RESPONSE:

i. Attachment 1 to this response provides Schedules 10.1.0 through 10.1.6 as well as Schedule 11.1.0 showing the customer bill impacts for the cost of service study scenario replacing "Peak and Average" with class "Coincident Design Peak" allocator.

ii. Attachment 2 to this response provides Schedules 10.1.0 through 10.1.6 as well as Schedule 11.1.0 showing the customer bill impacts for the cost of service study scenario directly assigning the cost of the two transmission mains in the amount of $3.738 million to the Special Contract class.

    As described in the response to IGU-Centra II-1e, service to the Special Contract class is not achieved solely through use of the two pipelines identified in the question. For purposes of this scenario, Centra has adjusted the rate base allocation to directly assign $3.378 million of Transmission Mains plant assets to the Special Contract rate class, and has continued to allocate all other types of plant assets as per the Cost Allocation Study.

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year

Attachment 1 IGU-Centra II -27 i)
Schedule 10.1.0

#	Cost of Service Elements	SGS Demand	SGS Energy	SGS Customer	SGS Total	LGS Demand	LGS Energy	LGS Customer	LGS Total	
5	Cost of Gas	31,969,513	1,508,864	0	33,478,377	24,007,190	1,125,616	0	25,132,806	
6	Other Income	-72,871	-452	-971,167	-1,044,489	-54,793	-345	-42,140	-97,278	
7	Operating & Maintenance Expenses	7,993,337	49,422	36,957,610	45,000,370	6,002,993	37,698	4,337,539	10,378,230	
8	Depreciation & Amortization	4,411,272	5,772,166	11,448,390	21,631,828	2,975,187	3,782,173	2,347,647	9,105,008	
9	Capital & Other Taxes	4,001,977	481,214	9,358,475	13,841,667	3,005,630	336,850	1,483,665	4,826,145	
10	Finance Expense	3,549,972	1,579,608	9,448,546	14,578,126	2,665,237	1,105,586	1,574,235	5,345,058	
11	Corporate Allocation	1,971,909	877,427	5,248,400	8,097,736	1,480,464	614,122	874,443	2,969,028	
12	Net Income	475,627	211,637	1,265,921	1,953,184	357,090	148,127	210,917	716,133	
14	Total Cost of Service	54,300,735	10,479,887	72,756,175	137,536,797	40,438,997	7,149,828	10,786,305	58,375,130	

#		HVF Demand	HVF Energy	HVF Customer	HVF Total	Cooperative Demand	Cooperative Energy	Cooperative Customer	Cooperative Total	
20	Cost of Gas	5,759,865	344,193	0	6,104,057	11,615	205	0	11,820	
21	Other Income	-14,773	-103	-9,094	-23,970	-20	0	-20	-41	
22	Operating & Maintenance Expenses	1,602,208	11,245	960,145	2,573,598	2,244	10	2,117	4,371	
23	Depreciation & Amortization	708,449	299,213	175,809	1,183,471	740	1	428	1,169	
24	Capital & Other Taxes	771,718	60,941	81,436	914,095	812	62	263	1,138	
25	Finance Expense	683,804	199,814	79,602	963,220	673	204	225	1,103	
26	Corporate Allocation	379,833	110,991	44,217	535,041	374	113	125	613	
27	Net Income	91,616	26,771	10,665	129,053	90	27	30	148	
29	Total Cost of Service	9,982,720	1,053,064	1,342,780	12,378,565	16,528	624	3,169	20,321	

#		Main Line Demand	Main Line Energy	Main Line Customer	Main Line Total	Special Contract Demand	Special Contract Energy	Special Contract Customer	Special Contract Total	
35	Cost of Gas	66,671	111,897	0	178,569	[redacted]				1d
36	Other Income	-5,787	-4	-767	-6,559	-4,973	-1	-86	-5,060	
37	Operating & Maintenance Expenses	632,491	444	80,931	713,866	544,111	92	8,563	552,765	
38	Depreciation & Amortization	195,644	99,452	15,830	310,926	62,247	-8	8,098	70,338	
39	Capital & Other Taxes	208,477	6,578	7,772	222,827	363,057	13	6,709	369,779	
40	Finance Expense	171,210	21,602	7,668	200,481	296,953	37	6,151	303,141	
41	Corporate Allocation	95,103	11,999	4,260	111,361	164,949	21	3,417	168,386	
42	Net Income	22,939	2,894	1,027	26,861	39,786	5	824	40,615	
44	Total Cost of Service	1,386,748	254,864	116,721	1,758,332	[redacted]				1e

#		Power Station Demand	Power Station Energy	Power Station Customer	Power Station Total	Interruptible Demand	Interruptible Energy	Interruptible Customer	Interruptible Total	
50	Cost of Gas	[redacted]				0	190,673	0	190,673	1d
51	Other Income	-645	-2	-194	-841	-117	-25	-1,629	-1,771	
52	Operating & Maintenance Expenses	70,550	181	17,129	87,860	780	2,739	171,800	175,318	
53	Depreciation & Amortization	-93,373	-15	43,729	-49,659	-21,989	166	34,224	12,401	
54	Capital & Other Taxes	22,296	25	37,805	60,126	1,319	10,639	16,482	28,440	
55	Finance Expense	17,709	73	34,897	52,679	1,312	34,848	16,333	52,493	
56	Corporate Allocation	9,837	41	19,384	29,262	729	19,357	9,073	29,158	
57	Net Income	2,373	10	4,675	7,058	176	4,669	2,188	7,033	
59	Total Cost of Service	[redacted]				-17,791	263,065	248,471	493,745	1e

#		Primary Gas Demand	Primary Gas Energy	Primary Gas Customer	Primary Gas Total	Supplemental Gas - Firm Demand	Supplemental Gas - Firm Energy	Supplemental Gas - Firm Customer	Supplemental Gas - Firm Total	
65	Cost of Gas	[redacted]				[redacted]				1a
66	Other Income									
67	Operating & Maintenance Expenses									
68	Depreciation & Amortization									
69	Capital & Other Taxes									1e
70	Finance Expense									
71	Corporate Allocation									
72	Net Income									
74	Total Cost of Service									1e

#		Supplemental Gas - Interruptible Demand	Supplemental Gas - Interruptible Energy	Supplemental Gas - Interruptible Customer	Supplemental Gas - Interruptible Total	Fixed Price Offering Demand	Fixed Price Offering Energy	Fixed Price Offering Customer	Fixed Price Offering Total	
80	Cost of Gas	[redacted]				0	44,879	0	44,879	1a
81	Other Income					0	-4	-171	-175	
82	Operating & Maintenance Expenses					0	419	18,750	19,168	
83	Depreciation & Amortization					0	33	1,486	1,520	
84	Capital & Other Taxes					0	19	304	323	1e
85	Finance Expense					0	43	146	189	
86	Corporate Allocation					0	24	81	105	
87	Net Income					0	6	20	25	
89	Total Cost of Service					0	45,418	20,616	66,034	1e

#		Unassigned Demand	Unassigned Energy	Unassigned Customer	Unassigned Total	Total Demand	Total Energy	Total Customer	Total Total
96	Cost of Gas	0	0	0	0	61,836,486	115,428,348	0	177,264,835
97	Other Income	0	0	0	0	-153,978	-10,480	-1,025,270	-1,189,728
98	Operating & Maintenance Expenses	0	0	0	0	16,848,713	1,146,704	42,554,583	60,550,000
99	Depreciation & Amortization	0	0	0	0	8,238,176	10,035,983	14,075,643	32,349,802
100	Capital & Other Taxes	0	0	0	0	8,375,286	943,305	10,992,913	20,311,504
101	Finance Expense	0	0	0	0	7,386,869	3,048,590	11,167,803	21,603,263
102	Corporate Allocation	0	0	0	0	4,103,197	1,693,405	6,203,398	12,000,000
103	Net Income	0	0	0	0	989,696	408,451	1,496,267	2,894,415
105	Total Cost of Service	0	0	0	0	107,624,446	132,694,307	85,465,338	325,784,091

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year

Attachment 1 IGU-Centra II-27 i)
Schedule 10.1.1

	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1 REVENUE REQUIREMENTS															
2 Upstream Demand ($)		[redacted]													
3 Upstream Commodity ($)															
4 Upstream Customer ($)															
5 Upstream Total ($)															
6															
7 Downstream Demand ($)															
8 Downstream Commodity ($)															1e
9 Downstream Customer ($)															
10 Downstream Total ($)															
11															
12 Total (incl. gas costs)															
13															
14															
15 MONTHLY BILLING DETERMINANTS															
16 Upstream Demand (10^3m^3-day)		[redacted]													
17 Upstream Commodity (10^3m^3)															
18 Upstream Customer (customers)															
19															
20 Downstream Demand (10^3m^3-day)															1d
21 Downstream Commodity (10^3m^3)															
22 Downstream Customer (customers)															
23															
24 PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25															
26 RESULTING UNIT CHARGES															
27 Upstream Demand ($/$10^3m^3$-day)		454.726	0.000	0.000	258.108	473.793	245.128	0.000	0.000	-0.023	0.000	0.000	0.000	0.000	
28 Upstream Commodity ($/$10^3m^3$)		80.314	51.427	48.871	13.599	2.310	2.509	0.000	0.000	2.597	76.908	134.897	134.294	80.883	
29 Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30															
31 Downstream Demand ($/$10^3m^3$-day)		248.552	0.000	0.000	162.431	177.901	171.676	90.658	2.948	-3.695	0.000	0.000	0.000	0.000	
32 Downstream Commodity ($/$10^3m^3$)		7.252	43.493	39.186	9.154	0.000	1.518	0.096	18.305	3.004	0.000	0.000	0.000	0.000	
33 Downstream Customer ($/customer)		24.749	21.707	108.165	1,008.093	264.053	1,080.749	2,806.285	6,559.405	1,035.295	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year

Attachment 1 IGU-Centra II-27 i)
Schedule 10.1.2

	Gas Costs vs. Non-Gas Costs	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,638,042	31,882,639	23,941,953	5,743,182	11,584	58,684	0	0	0	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,301,940	1,190,871	894,206	214,355	433	2,185	0	0	-110	0	0	0	0	
5	Total	Total	63,939,983	33,073,510	24,836,160	5,957,536	12,016	60,869	0	0	-110	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]	[redacted]	[redacted]	44,879	
9	Non-gas Costs	Non-gas Costs	3,663,952	1,082,974	856,047	300,482	419	6,588	0	0	71,841	[redacted]	[redacted]	[redacted]	539	1a,1e
10	Total	Total	117,614,218	2,024,254	1,575,190	514,603	624	10,585	0	0	119,139	[redacted]	[redacted]	[redacted]	45,418	
11			0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,588,308	32,823,919	24,661,096	5,957,303	11,789	62,682	0	0	47,299	[redacted]	[redacted]	[redacted]	44,879	
19	Total Non-gas Costs	Total Non-gas Costs	5,965,892	2,273,845	1,750,253	514,836	851	8,773	0	0	71,731	[redacted]	[redacted]	[redacted]	539	1e
20	Total Upstream Costs	Total Upstream Costs	181,554,200	35,097,764	26,411,350	6,472,139	12,640	71,455	0	0	119,030	[redacted]	[redacted]	[redacted]	45,418	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	198,444	86,873	65,237	16,683	32	7,987	[redacted]	[redacted]	0	0	0	0	0	
24	Non-gas Costs	Non-gas Costs	43,486,019	21,140,352	15,537,601	4,008,501	4,480	1,317,892	1,466,129	28,746	-17,681	0	0	0	0	2d,1e
25	Total	Total	43,684,463	21,227,225	15,602,837	4,025,184	4,512	1,325,878	[redacted]	[redacted]	-17,681	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]	[redacted]	143,374	0	0	0	0	
29	Non-gas Costs	Non-gas Costs	13,602,006	7,888,049	5,168,165	408,390	0	136,378	159	313	552	0	0	0	0	2d,1e
30	Total	Total	15,080,089	8,455,633	5,574,638	538,461	0	244,278	[redacted]	[redacted]	143,926	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]	[redacted]	0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	33,675	157,426	248,471	0	0	0	20,616	2d,1e
35	Total	Total	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]	[redacted]	248,471	0	0	0	20,616	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,676,527	654,457	471,710	146,754	32	115,887	[redacted]	[redacted]	143,374	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	142,553,363	101,784,576	31,492,070	5,759,671	7,649	1,570,991	1,499,964	186,485	231,341	0	0	0	20,616	2d,1e
40	Total Downstream Costs	Total Downstream Costs	144,229,890	102,439,033	31,963,780	5,906,425	7,681	1,686,878	[redacted]	[redacted]	374,715	0	0	0	20,616	
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	33,478,377	25,132,806	6,104,057	11,820	178,569	[redacted]	[redacted]	190,673	[redacted]	[redacted]	[redacted]	44,879	
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	148,519,256	104,058,421	33,242,324	6,274,507	8,500	1,579,764	1,499,964	186,485	303,072	[redacted]	[redacted]	[redacted]	21,155	2d,1e
44	Grand Total	Grand Total	325,784,091	137,536,797	58,375,130	12,378,565	20,321	1,758,332	[redacted]	[redacted]	493,745	[redacted]	[redacted]	[redacted]	66,034	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 10.1.1, line 17, PG column)
49 0.91 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR 21,155 (lines 9 & 34, FPO column)
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column)
37.67 per 10^3m^3

1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year

Attachment 1 IGU-Centra II-27 i)
Schedule 10.1.3

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION																
2	Demand	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3	Energy	113,369,822	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
4	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
5	Total	113,369,822	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
6																	
7	PIPELINE																
8	Demand	44,875,222	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
9	Energy	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
10	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
11	Total	44,875,222	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
12																	
13	STORAGE																
14	Demand	19,064,760	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
15	Energy	4,244,395	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
16	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
17	Total	23,309,156	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
18																	
19	TRANSMISSION																
20	Demand	17,108,649	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
21	Energy	15,080,089	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
22	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
23	Total	32,188,738	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
24																	
25	DISTRIBUTION																
26	Demand	26,575,814	11,234,774	2,166,751	13,401,525	10,067,373	2,584,237	1,987	514,733	[redacted]	[redacted]	5,960	[redacted]	[redacted]	[redacted]	0	
27	Energy	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	2d,1e
28	Customer	11,024,589	10,001,064	700,104	10,701,168	318,376	4,253	2	20	[redacted]	[redacted]	766	[redacted]	[redacted]	[redacted]	0	
29	Total	37,600,403	21,235,838	2,866,855	24,102,693	10,385,749	2,588,489	1,989	514,753	[redacted]	[redacted]	6,726	[redacted]	[redacted]	[redacted]	0	
30																	
31	ONSITE																
32	Demand	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	
33	Energy	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	2d,1e
34	Customer	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]	[redacted]	247,705	[redacted]	[redacted]	[redacted]	20,616	
35	Total	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]	[redacted]	247,705	[redacted]	[redacted]	[redacted]	20,616	
36																	
37	TOTAL SERVICE																
38	Demand	107,624,446	45,474,800	8,825,936	54,300,735	40,438,997	9,982,720	16,528	1,386,748	[redacted]	[redacted]	-17,791	[redacted]	[redacted]	[redacted]	0	
39	Energy	132,694,307	8,027,388	2,452,499	10,479,887	7,149,828	1,053,064	624	254,864	[redacted]	[redacted]	263,065	[redacted]	[redacted]	[redacted]	45,418	2d,1e
40	Customer	85,465,338	65,662,001	7,094,174	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]	[redacted]	248,471	[redacted]	[redacted]	[redacted]	20,616	
41	Total	325,784,091	119,164,188	18,372,609	137,536,797	58,375,130	12,378,565	20,321	1,758,332	[redacted]	[redacted]	493,745	[redacted]	[redacted]	[redacted]	66,034	

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Rate Base
2019/20 Test Year

Attachment 1 IGU-centra II-27 i)
Schedule 10.1.4
Page 1 of 4

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
RATE BASE DETAILS											
I. GAS PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Franchises & Consents	401	22,384		0	22,384		13,300	1,976	15,277	5,275	1,008
Other Intangible Plant	402	13,614,400		0	13,614,400		8,089,719	1,201,971	9,291,690	3,208,401	613,076
Sub-total	401-402	13,636,784		0	13,636,784		8,103,019	1,203,947	9,306,967	3,213,676	614,084
B. PRODUCTION PLANT											
(Reserved)	-	0		0	0		0	0	0	0	0
Sub-total	420-424	0		0	0		0	0	0	0	0
C. LOCAL STORAGE PLANT											
Land	440	0		0	0		0	0	0	0	0
Structures & Improvements	442	0		0	0		0	0	0	0	0
Sub-total	440-449	0		0	0		0	0	0	0	0
D. TRANSMISSION PLANT											
Land	460	1,027,343		0	1,027,343		377,018	72,725	449,743	337,730	86,369
Structures & Improvements	461	76,420		0	76,420		28,045	5,410	33,455	25,122	6,425
Structures & Improvements - M&R	463	1,363,403		0	1,363,403		500,347	96,514	596,861	448,207	114,621
Mains	465	155,008,042		0	155,008,042		56,885,430	10,972,907	67,858,337	50,957,549	13,031,492
Measuring & Reg. Equipment	467	14,466,096		0	14,466,096		5,308,822	1,024,044	6,332,866	4,755,604	1,216,162
Other Transmission Equipment	469	0		0	0		0	0	0	0	0
Sub-total	460-469	171,941,305		0	171,941,305		63,099,662	12,171,600	75,271,262	56,524,212	14,455,068
E. DISTRIBUTION PLANT											
Land	470	1,764,150		0	1,764,150		1,148,414	163,463	1,311,877	374,718	62,235
Computer Equipment - Hardware	471	1,180,367		0	1,180,367		768,387	109,371	877,758	250,718	41,641
Structures & Improvements	472	1,377,038		0	1,377,038		594,122	114,603	708,725	532,210	136,103
Structures & Improvements: M & R	472.1	5,596,871		0	5,596,871		2,173,126	415,409	2,588,535	1,980,008	602,855
Services	473	284,239,631		0	284,239,631		227,894,619	30,429,150	258,323,769	24,635,436	962,180
Regulators	474	56,621,401		0	56,621,401		29,755,325	5,699,896	35,455,221	19,792,703	1,059,822
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	231,880,662		0	231,880,662		136,814,242	17,773,853	154,588,095	61,978,345	15,308,850
Measuring & Reg. Equipment	477	52,283,320		0	52,283,320		20,664,028	3,985,985	24,650,013	18,510,684	4,733,780
Telemetry Equipment	477.1	5,363,336		0	5,363,336		2,209,068	426,118	2,635,186	1,978,867	506,060
Meters	478	46,179,936		0	46,179,936		24,268,191	4,648,787	28,916,978	16,142,761	864,382
AMR/ERT Modules	479	1,703,806		0	1,703,806		1,703,806	0	1,703,806	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	688,190,519		0	688,190,519		447,993,327	63,766,634	511,759,961	146,176,449	24,277,909
F. GENERAL PLANT											
Land	480	136,000		0	136,000		91,414	9,660	101,074	23,310	5,781
Structures & Improvements	482	8,619,031		0	8,619,031		5,793,400	612,208	6,405,608	1,477,296	366,341
Leasehold Improvements	482.1	0		0	0		0	0	0	0	0
Office Furniture & Equipment	483	0		0	0		0	0	0	0	0
Target Adjustments	483.1	0		0	0		0	0	0	0	0
Computer Equipment: Software	483.2	0		0	0		0	0	0	0	0
Computer System Development	483.3	0		0	0		0	0	0	0	0
Transportation Equipment	484	-655		0	-655		-440	-47	-487	-112	-28
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	185,134		0	185,134		107,887	16,143	124,031	44,673	8,799
Tools & Work Equipment	486	188		0	188		109	16	126	45	9
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Deferred Ineligible Overhead	488	3,849,973		0	3,849,973		2,587,812	273,463	2,861,275	659,883	163,638
Property, Plant & Equipment Gas Inventory	489	297,209		0	297,209		179,963	26,110	206,073	67,581	12,703
Sub-total	480-490	13,086,880		0	13,086,880		8,760,146	937,554	9,697,700	2,272,676	557,243
Sub-total Plant-in-Service		886,855,489		0	886,855,489		527,956,155	78,079,735	606,035,890	208,187,013	39,904,304
G. ADDITIONS TO UTILITY PLANT											
Construction Work in Progress		0		0	0		0	0	0	0	0
Other Additions		0		0	0		0	0	0	0	0
Sub-total		0		0	0		0	0	0	0	0
Total Utility Plant		**886,855,489**		**0**	**886,855,489**		**527,956,155**	**78,079,735**	**606,035,890**	**208,187,013**	**39,904,304**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-5,220,747		0	-5,220,747		-3,129,492	-462,622	-3,592,114	-1,193,613	-234,749
Production Plant		0		0	0		0	0	0	0	0
Local Storage Plant		0		0	0		0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO
RATE BASE DETAILS												
I. GAS PLANT IN SERVICE												
A. INTANGIBLE PLANT												
Franchises & Consents	401	22,384	1	263	468	74	17	0	0	0	0	0
Other Intangible Plant	402	13,614,400	781	159,768	284,843	45,257	10,585	0	0	0	0	0
Sub-total	401-402	13,636,784	782	160,031	285,311	45,332	10,602	0	0	0	0	0
B. PRODUCTION PLANT												
(Reserved)	-	0	0	0	0	0	0	0	0	0	0	0
Sub-total	420-424	0	0	0	0	0	0	0	0	0	0	0
C. LOCAL STORAGE PLANT												
Land	440	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	442	0	0	0	0	0	0	0	0	0	0	0
Sub-total	440-449	0	0	0	0	0	0	0	0	0	0	0
D. TRANSMISSION PLANT												
Land	460	1,027,343	163	41,347	105,644	6,347	0	0	0	0	0	0
Structures & Improvements	461	76,420	12	3,076	7,858	472	0	0	0	0	0	0
Structures & Improvements - M&R	463	1,363,403	217	54,872	140,202	8,423	0	0	0	0	0	0
Mains	465	155,008,042	24,655	6,238,561	15,939,842	957,607	0	0	0	0	0	0
Measuring & Reg. Equipment	467	14,466,096	2,301	582,213	1,487,583	89,368	0	0	0	0	0	0
Other Transmission Equipment	469	0	0	0	0	0	0	0	0	0	0	0
Sub-total	460-469	171,941,305	27,348	6,920,069	17,681,129	1,062,217	0	0	0	0	0	0
E. DISTRIBUTION PLANT												
Land	470	1,764,150	56	8,136	807	4,607	1,714	0	0	0	0	0
Computer Equipment - Hardware	471	1,180,367	38	5,444	540	3,082	1,147	0	0	0	0	0
Structures & Improvements	472	1,377,038	0	0	0	0	0	0	0	0	0	0
Structures & Improvements: M & R	472.1	5,596,871	969	365,114	0	0	59,391	0	0	0	0	0
Services	473	284,239,631	0	112,363	0	0	205,884	0	0	0	0	0
Regulators	474	56,621,401	0	95,980	0	0	217,675	0	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0	0
Mains	475	231,880,662	0	0	0	0	5,372	0	0	0	0	0
Measuring & Reg. Equipment	477	52,283,320	19,956	2,266,201	313,332	1,789,355	0	0	0	0	0	0
Telemetry Equipment	477.1	5,363,336	957	242,266	0	0	0	0	0	0	0	0
Meters	478	46,179,936	0	78,281	0	0	177,534	0	0	0	0	0
AMR/ERT Modules	479	1,703,806	0	0	0	0	0	0	0	0	0	0
Other Distribution Equipment	-	0	0	0	0	0	0	0	0	0	0	0
Sub-total	470-479	688,190,519	21,976	3,173,784	314,678	1,797,044	668,717	0	0	0	0	0
F. GENERAL PLANT												
Land	480	136,000	10	1,603	1,242	197	394	2,051	277	18	0	43
Structures & Improvements	482	8,619,031	622	101,616	78,684	12,506	24,956	129,969	17,574	1,131	0	2,729
Leasehold Improvements	482.1	0	0	0	0	0	0	0	0	0	0	0
Office Furniture & Equipment	483	0	0	0	0	0	0	0	0	0	0	0
Target Adjustments	483.1	0	0	0	0	0	0	0	0	0	0	0
Computer Equipment: Software	483.2	0	0	0	0	0	0	0	0	0	0	0
Computer System Development	483.3	0	0	0	0	0	0	0	0	0	0	0
Transportation Equipment	484	-655	0	-8	-6	-1	-2	-10	-1	0	0	0
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	185,134	11	2,403	4,460	623	135	0	0	0	0	0
Tools & Work Equipment	486	188	0	2	5	1	0	0	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0	0
Deferred Ineligible Overhead	488	3,849,973	278	45,390	35,147	5,586	11,147	58,055	7,850	505	0	1,219
Property, Plant & Equipment Gas Inventory	489	297,209	17	3,397	6,216	990	233	0	0	0	0	0
Sub-total	480-490	13,086,880	938	154,403	125,746	19,903	36,863	190,065	25,699	1,654	0	3,990
Sub-total Plant-in-Service		886,855,489	51,044	10,408,287	18,406,865	2,924,495	716,182	190,065	25,699	1,654	0	3,990
G. ADDITIONS TO UTILITY PLANT												
Construction Work in Progress		0	0	0	0	0	0	0	0	0	0	0
Other Additions		0	0	0	0	0	0	0	0	0	0	0
Sub-total		0	0	0	0	0	0	0	0	0	0	0
Total Utility Plant		**886,855,489**	**51,044**	**10,408,287**	**18,406,865**	**2,924,495**	**716,182**	**190,065**	**25,699**	**1,654**	**0**	**3,990**
II. ACCUMULATED DEPRECIATION												
Intangible Plant		-5,220,747	-339	-65,069	-109,909	-21,526	-3,428	0	0	0	0	0
Production Plant		0	0	0	0	0	0	0	0	0	0	0
Local Storage Plant		0	0	0	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential	Small Commercial	Small Gen. Service	Large Gen Service	High Volume
							SGS-R	SGS-C	SGS-Total	LGS	HVF
Transmission Plant		-41,188,559		0	-41,188,559		-15,103,143	-2,913,318	-18,016,461	-13,529,278	-3,468,870
Distribution Plant		-228,870,742		0	-228,870,742		-148,545,174	-21,031,329	-169,576,502	-48,159,920	-8,706,935
General Plant		-7,482,792		0	-7,482,792		-4,959,437	-541,418	-5,500,855	-1,365,256	-328,278
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-282,762,840		0	-282,762,840		-171,737,246	-24,948,686	-196,685,932	-64,248,068	-12,738,833
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-282,762,840**		**0**	**-282,762,840**		**-171,737,246**	**-24,948,686**	**-196,685,932**	**-64,248,068**	**-12,738,833**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-61,613,212		0	-61,613,212		-24,761,101	-4,617,860	-29,378,961	-19,984,144	-4,971,661
Cash Working Capital		13,933,390		0	13,933,390		6,486,367	955,268	7,441,635	2,709,969	533,858
Security Deposits		-900,000		0	-900,000		-723,624	-50,656	-774,280	-102,995	-17,517
Gas in Storage		33,138,755		0	33,138,755		13,001,916	2,442,022	15,443,938	12,229,506	4,326,060
Investment in DSM		53,559,521		0	53,559,521		23,030,594	8,033,928	31,064,522	20,352,618	1,606,786
Investment in Regulatory Costs		2,847,151		0	2,847,151		1,913,752	202,233	2,115,984	488,000	121,014
Investment in Site Restoration		1,608,420		0	1,608,420		973,912	141,301	1,115,213	365,732	68,748
Total Other Rate Base		**42,574,026**		**0**	**42,574,026**		**19,921,816**	**7,106,235**	**27,028,052**	**16,058,687**	**1,667,287**
TOTAL RATE BASE		**646 666 675**		**0**	**646 666 675**		**376 140 726**	**60 237 284**	**436 378 010**	**159 997 633**	**28 832 758**

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO
Transmission Plant		-41,188,559	-6,546	-1,674,339	-4,234,269	-258,759	-37	0	0	0	0	0
Distribution Plant		-228,870,742	-9,567	-1,350,107	-132,813	-758,457	-176,440	0	0	0	0	0
General Plant		-7,482,792	-494	-59,315	-73,021	-6,891	-21,270	-109,375	-14,789	-952	0	-2,296
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0	0
Sub-total		-282,762,840	-16,946	-3,148,829	-4,550,011	-1,045,634	-201,175	-109,375	-14,789	-952	0	-2,296
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-282,762,840**	**-16,946**	**-3,148,829**	**-4,550,011**	**-1,045,634**	**-201,175**	**-109,375**	**-14,789**	**-952**	**0**	**-2,296**
III. OTHER RATE BASE												
Contributions in Aid of Construction		-61,613,212	-8,178	-2,046,178	-4,900,152	-314,496	-9,443	0	0	0	0	0
Cash Working Capital		13,933,390	840	106,286	57,972	3,348	21,688	2,670,416	361,076	23,240	0	3,063
Security Deposits		-900,000	-158	-1,420	-158	-316	-3,156	0	0	0	0	0
Gas in Storage		33,138,755	6,110	95,453	0	0	1,037,688	0	0	0	0	0
Investment in DSM		53,559,521	0	535,595	0	0	0	0	0	0	0	0
Investment in Regulatory Costs		2,847,151	206	33,567	25,992	4,131	8,244	42,933	5,805	374	0	901
Investment in Site Restoration		1,608,420	90	18,382	33,637	5,356	1,262	0	0	0	0	0
Total Other Rate Base		**42,574,026**	**-1,090**	**-1,258,315**	**-4,782,709**	**-301,977**	**1,056,283**	**2,713,349**	**366,881**	**23,613**	**0**	**3,964**
TOTAL RATE BASE		**646 666 675**	**33 009**	**6 001 143**	**9 074 145**	**1 576 884**	**1 571 289**	**2 794 038**	**377 791**	**24 316**	**0**	**5 658**

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	
COST OF SERVICE DETAILS												
I. COST OF GAS												
A. FIXED COSTS		[redacted]		[redacted]			[redacted]					
TCPL FS Demand - Sask Zone												
TCPL STS Demand												
[redacted]												
TCPL Firm Service - Emerson to Man Zone												
TCPL FS Demand - Man Zone												
Other Pipeline Fixed Tolls												
ANR Storage Deliverability												
ANR Joliet to Storage Winter												
ANR Crystal Falls from Storage												
GLGT Storage to Deward												1a
Seasonal Storage Capacity												
Seasonal Storage Deliverability												
Annual Storage Capacity												
Annual Storage Deliverability												
ANR Joliet to Storage Summer												
ANR Crystal Falls to Storage												
GLGT Emerson to Crystal Falls												
Forecast Capacity Management Revenues												
Sub-total												
B. VARIABLE TRANSPORTATION												
TCPL FS - Sask Zone												
TCPL FS - Flowing directly to Man Zone												
TCPL FS - SSDA (Welwyn)												
Firm Service - Emerson to Man Zone												
GLGT Storage Transportation												
ANR Storage Transportation												
ANR Storage Withdrawl Chg.												
Storage Gas - Transportation & Delivery Cost												
Compressor Fuel: TCPL SSDA												1a
Compressor Fuel: Primary												
Compressor Fuel: Emerson												
Compressor Fuel: TCPL SSDA (Welwyn) to MDA												
Compressor Fuel: Oklahoma												
Compressor Fuel: Storage & Supplemental US Supplies												
Sub-total												
C. COMMODITY COST												
Primary Direct to System												
Storage Gas: Primary to System												
Oklahoma Supply												
Storage Gas: Supplemental Supply												1a
Emerson Supply												
Delivered Service												
Fixed Price Offering												
Sub-total												
D. OTHER GAS COSTS												
Minell Charges												
Load Balancing Charges												
Baseload Volume Price Increment Charges												1a
Sub-total												
Total Cost of Gas		**177,264,835**		**0**	**177,264,835**		**28,067,499**	**5,410,877**	**33,478,377**	**25,132,806**	**6,104,057**	
II. OTHER REVENUE												
Rental Income		0		0	0		0	0	0	0	0	
Late Payment Charge		-618,595		0	-618,595		-578,125	-40,470	-618,595	0	0	
Broker Revenue		-17,774		0	-17,774		-13,294	-1,527	-14,821	-2,500	-320	
Other		-553,358		0	-553,358		-371,803	-39,270	-411,073	-94,777	-23,651	
Total Other Revenue		**-1,189,728**		**0**	**-1,189,728**		**-963,222**	**-81,268**	**-1,044,489**	**-97,278**	**-23,970**	

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
COST OF SERVICE DETAILS														
I. COST OF GAS														
A. FIXED COSTS		[redacted]												
TCPL FS Demand - Sask Zone														
TCPL STS Demand														
[redacted]														
TCPL Firm Service - Emerson to Man Zone														
TCPL FS Demand - Man Zone														
Other Pipeline Fixed Tolls														
ANR Storage Deliverability														
ANR Joliet to Storage Winter														
ANR Crystal Falls from Storage														
GLGT Storage to Deward														
Seasonal Storage Capacity														1a
Seasonal Storage Deliverability														
Annual Storage Capacity														
Annual Storage Deliverability														
ANR Joliet to Storage Summer														
ANR Crystal Falls to Storage														
GLGT Emerson to Crystal Falls														
Forecast Capacity Management Revenues														
Sub-total														
B. VARIABLE TRANSPORTATION		[redacted]												
TCPL FS - Sask Zone														
TCPL FS - Flowing directly to Man Zone														
TCPL FS - SSDA (Welwyn)														
Firm Service - Emerson to Man Zone														
GLGT Storage Transportation														
ANR Storage Transportation														
ANR Storage Withdrawl Chg.														
Storage Gas - Transportation & Delivery Cost														1a
Compressor Fuel: TCPL SSDA														
Compressor Fuel: Primary														
Compressor Fuel: Emerson														
Compressor Fuel: TCPL SSDA (Welwyn) to MDA														
Compressor Fuel: Oklahoma														
Compressor Fuel: Storage & Supplemental US Supplies														
Sub-total														
C. COMMODITY COST		[redacted]												
Primary Direct to System														
Storage Gas: Primary to System														
Oklahoma Supply														
Storage Gas: Supplemental Supply														1a
Emerson Supply														
Delivered Service														
Fixed Price Offering														
Sub-total														
D. OTHER GAS COSTS		[redacted]												
Minell Charges														
Load Balancing Charges														
Baseload Volume Price Increment Charges														1a
Sub-total														
Total Cost of Gas		**177,264,835**	**11,820**	**178,569**	[redacted]		**190,673**	[redacted]			**0**	**44,879**	**0**	1a,2d
II. OTHER REVENUE														
Rental Income		0	0	0	0	0					0	0	0	
Late Payment Charge		-618,595	0	0	0	0					0	0	0	
Broker Revenue		-17,774	-1	-28	-8	-38	-59				0	0	0	1e
Other		-553,358	-40	-6,531	-5,052	-803	-1,712				0	-175	0	
Total Other Revenue		**-1,189,728**	**-41**	**-6,559**	**-5,060**	**-841**	**-1,771**				**0**	**-175**	**0**	

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Allocation Results of Cost of Service Elements
2019/20 Test Year

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
III. OPERATING & ADMINISTRATIVE EXPENSES											
A. CUSTOMER SERVICE & CORPORATE RELATIONS											
Back/Middle Office Services		294,425		0	294,425		46,618	8,987	55,605	41,744	10,138
Billing & Collections		7,705,172		1,572,397	6,132,775		6,267,453	502,418	6,769,871	780,447	119,366
Customer & Public Relations		4,008,554		0	4,008,554		2,593,005	185,072	2,778,077	660,256	431,167
Customer Information Systems (Banner)		533,983		0	533,983		484,409	33,910	518,319	15,421	206
Customer Inspections		7,151,177		2,391,625	4,759,551		6,234,373	461,336	6,695,709	324,062	48,342
Customer Safety Services		1,285,355		0	1,285,355		842,537	58,980	901,517	377,325	5,021
Dispatch		2,306,190		0	2,306,190		1,809,546	239,158	2,048,703	247,197	7,868
Energy Supply, Planning & Support		2,869,025		218,679	2,650,347		849,996	163,932	1,013,928	761,849	245,702
Environment		398,798		0	398,798		199,662	29,632	229,294	116,412	29,213
Meter Reading		2,511,105		0	2,511,105		2,011,022	165,165	2,176,187	316,691	13,997
Rate and Regulatory Affairs		943,878		0	943,878		634,441	67,043	701,484	161,780	40,118
Sub-total		30,007,662		4,182,701	25,824,961		21,973,062	1,915,633	23,888,695	3,803,184	951,139
B. OPERATIONS AND MAINTENANCE											
Communication System		135,343		0	135,343		23,363	4,507	27,869	20,928	65,234
Distribution Maintenance		6,758,662		0	6,758,662		3,979,976	680,118	4,660,094	1,560,443	303,767
Load Forecast		70,288		0	70,288		32,845	2,299	35,144	17,694	13,545
Metering		573,718		0	573,718		401,250	28,089	429,339	81,856	48,194
Plant Failures & Emergencies		302,792		0	302,792		198,477	13,894	212,371	88,887	1,183
Quality Assessment		434,989		0	434,989		252,897	43,335	296,232	101,866	20,124
Regulating Station Maintenance		5,376,364		426,161	4,950,203		2,913,555	404,642	3,318,197	1,503,611	374,641
System Performance & Reliability		2,513,109		0	2,513,109		1,258,213	186,730	1,444,943	733,597	184,090
Sub-total		16,165,264		426,161	15,739,104		9,060,576	1,363,614	10,424,190	4,108,881	1,010,779
C. ORGANIZATIONAL SUPPORT											
Corporate Governance		2,156,541		0	2,156,541		1,451,678	153,585	1,605,264	371,574	92,263
Corporate Infrastructure		4,581,302		0	4,581,302		3,079,385	325,409	3,404,794	785,232	194,722
Corporate Services		1,864,893		0	1,864,893		1,253,514	132,463	1,385,977	319,641	79,265
Departmental Support		5,446,970		0	5,446,970		3,661,256	386,897	4,048,153	933,607	231,516
Operational Management		1,657,966		0	1,657,966		1,114,425	117,765	1,232,190	284,174	70,470
Sub-total		15,707,672		0	15,707,672		10,560,258	1,116,119	11,676,377	2,694,229	668,236
D. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		852,395		0	852,395		572,949	60,545	633,494	146,100	36,230
Depreciation, Interest, Taxes		-2,182,994		0	-2,182,994		-1,467,329	-155,058	-1,622,387	-374,164	-92,785
Sub-total		-1,330,599		0	-1,330,599		-894,380	-94,512	-988,892	-228,064	-56,555
Total Operating & Administrative Expenses		**60,550,000**		**4,608,862**	**55,941,138**		**40,699,516**	**4,300,854**	**45,000,370**	**10,378,230**	**2,573,598**

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Cost of Service Elements
2019/20 Test Year

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
III. OPERATING & ADMINISTRATIVE EXPENSES														
A. CUSTOMER SERVICE & CORPORATE RELATIONS								[redacted]						
Back/Middle Office Services		294,425	20	297	103	137	317	[redacted]			0	75	0	
Billing & Collections		7,705,172	1,075	9,678	1,075	2,151	21,507	[redacted]			0	0	0	
Customer & Public Relations		4,008,554	0	35,014	4,002	8,003	78,030	[redacted]			0	14,005	0	
Customer Information Systems (Banner)		533,983	0	0	0	0		[redacted]			0	0	0	
Customer Inspections		7,151,177	102	22,360	56,817	3,441	343	[redacted]			0	0	0	
Customer Safety Services		1,285,355	45	407	45	90	905	[redacted]			0	0	0	
Dispatch		2,306,190	0	1,405	0	0	1,017	[redacted]			0	0	0	1e
Energy Supply, Planning & Support		2,869,025	363	142,148	76,033	32,849	1,729	[redacted]			0	238	0	
Environment		398,798	25	6,431	16,431	987	6	[redacted]			0	0	0	
Meter Reading		2,511,105	0	1,380	153	307	2,390	[redacted]			0	0	0	
Rate and Regulatory Affairs		943,878	68	11,128	8,617	1,370	2,733	[redacted]			0	299	0	
Sub-total		30,007,662	1,699	230,247	163,276	49,335	109,014	[redacted]			0	14,617	0	
B. OPERATIONS AND MAINTENANCE								[redacted]						
Communication System		135,343	10	7,417	1,931	1,163	10,790	[redacted]			0	0	0	
Distribution Maintenance		6,758,662	309	81,441	141,871	8,523	2,215	[redacted]			0	0	0	
Load Forecast		70,288	0	1,098	122	244	2,441	[redacted]			0	0	0	
Metering		573,718	434	3,908	434	868	8,684	[redacted]			0	0	0	
Plant Failures & Emergencies		302,792	11	96	11	21	213	[redacted]			0	0	0	1e
Quality Assessment		434,989	22	5,655	10,331	621	138	[redacted]			0	0	0	
Regulating Station Maintenance		5,376,364	709	179,105	0	3	98	[redacted]			0	0	0	
System Performance & Reliability		2,513,109	160	40,524	103,540	6,220	35	[redacted]			0	0	0	
Sub-total		16,165,264	1,655	319,244	258,240	17,663	24,612	[redacted]			0	0	0	
C. ORGANIZATIONAL SUPPORT								[redacted]						
Corporate Governance		2,156,541	135	20,299	19,687	3,129	6,309	[redacted]			0	683	0	
Corporate Infrastructure		4,581,302	331	54,012	41,823	6,648	13,265	[redacted]			0	1,450	0	
Corporate Services		1,864,893	135	21,987	17,025	2,706	5,400	[redacted]			0	590	0	
Departmental Support		5,446,970	393	64,218	49,726	7,904	15,771	[redacted]			0	1,724	0	1e
Operational Management		1,657,966	120	19,547	15,136	2,406	4,801	[redacted]			0	525	0	
Sub-total		15,707,672	1,113	180,062	143,396	22,792	45,545	[redacted]			0	4,973	0	
D. ADJUSTMENTS TO INCOME								[redacted]						
Corporate Alloc. & Adj.		852,395	62	10,049	7,782	1,237	2,468	[redacted]			0	270	0	
Depreciation, Interest, Taxes		-2,182,994	-158	-25,737	-19,929	-3,168	-6,321	[redacted]			0	-691	0	1e
Sub-total		-1,330,599	-96	-15,687	-12,147	-1,931	-3,853	[redacted]			0	-421	0	
Total Operating & Administrative Expenses		**60,550,000**	**4,371**	**713,866**	**552,765**	**87,860**	**175,318**	[redacted]			**0**	**19,168**	**0**	1e

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		17,180,097		0	17,180,097		9,841,908	1,515,117	11,357,025	4,436,879	751,026
Amortization of Cust. Contributions		-1,130,083		0	-1,130,083		-147,676	41,330	-106,345	-316,425	-140,567
Depreciation: Common Assets		4,547,217		0	4,547,217		3,056,474	322,988	3,379,462	779,390	193,274
Amortization Expense (Deferreds)		1,806,963		0	1,806,963		1,073,703	159,531	1,233,234	425,833	81,370
Demand Side Management Amortization Expense (Deferred)		9,945,608		0	9,945,608		4,276,611	1,491,841	5,768,452	3,779,331	298,368
Furnace Replacement Program		0		0	0		0	0	0	0	0
Ex-Franchise Depreciation & Amortization		0		0	0		0	0	0	0	0
Total Depreciation & Amortization Expenses		**32,349,802**		**0**	**32,349,802**		**18,101,021**	**3,530,807**	**21,631,828**	**9,105,008**	**1,183,471**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		12,900,000		0	12,900,000		7,665,220	1,138,899	8,804,119	3,040,044	580,906
Payroll Tax		839,629		0	839,629		564,368	59,639	624,007	143,912	35,687
Taxes on Common Assets		93,000		0	93,000		53,782	8,675	62,457	23,239	4,210
Corporate Capital Tax		3,286,134		0	3,286,134		1,900,371	306,532	2,206,902	821,144	148,760
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		3,192,741		0	3,192,741		1,846,362	297,820	2,144,182	797,807	144,532
Total Taxes		**20,311,504**		**0**	**20,311,504**		**12,030,102**	**1,811,564**	**13,841,667**	**4,826,145**	**914,095**
VI. FINANCE EXPENSE		**21,603,263**		**0**	**21,603,263**		**12,565,773**	**2,012,353**	**14,578,126**	**5,345,058**	**963,220**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,979,931**	**1,117,805**	**8,097,736**	**2,969,028**	**535,041**
VIII. NET INCOME (LOSS)		**2,894,415**		**0**	**2,894,415**		**1,683,568**	**269,616**	**1,953,184**	**716,133**	**129,053**
COST OF SERVICE SUMMARY											
COST OF GAS		177,264,835		0	177,264,835		28,067,499	5,410,877	33,478,377	25,132,806	6,104,057
OTHER REVENUE		-1,189,728		0	-1,189,728		-963,222	-81,268	-1,044,489	-97,278	-23,970
OPERATING EXPENSES											
Customer Service & Corporate Relations		30,007,662		4,182,701	25,824,961		21,973,062	1,915,633	23,888,695	3,803,184	951,139
Operations & Maintenance		16,165,264		426,161	15,739,104		9,060,576	1,363,614	10,424,190	4,108,881	1,010,779
Organizational Suport		15,707,672		0	15,707,672		10,560,258	1,116,119	11,676,377	2,694,229	668,236
Adjustments to Income		-1,330,599		0	-1,330,599		-894,380	-94,512	-988,892	-228,064	-56,555
Sub-total		60,550,000		4,608,862	55,941,138		40,699,516	4,300,854	45,000,370	10,378,230	2,573,598
DEPRECIATION & AMORTIZATION		32,349,802		0	32,349,802		18,101,021	3,530,807	21,631,828	9,105,008	1,183,471
CAPITAL & OTHER TAXES		20,311,504		0	20,311,504		12,030,102	1,811,564	13,841,667	4,826,145	914,095
FINANCE EXPENSE		21,603,263		0	21,603,263		12,565,773	2,012,353	14,578,126	5,345,058	963,220
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,979,931	1,117,805	8,097,736	2,969,028	535,041
NET INCOME		2,894,415		0	2,894,415		1,683,568	269,616	1,953,184	716,133	129,053
COST OF SERVICE		325,784,091		4,608,862	321,175,229		119,164,188	18,372,609	137,536,797	58,375,130	12,378,565

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
IV. DEPRECIATION & AMORTIZATION														
Depreciation Expense		17,180,097	1,027	209,759	339,741	58,828	21,367	[redacted]			0	80	0	
Amortization of Cust. Contributions		-1,130,083	-290	-73,104	-348,721	-121,093	-23,537	[redacted]			0	0	0	
Depreciation: Common Assets		4,547,217	328	53,610	41,512	6,598	13,166	[redacted]			0	1,440	0	
Amortization Expense (Deferreds)		1,806,963	104	21,205	37,806	6,007	1,405	[redacted]			0	0	0	1e
Demand Side Management Amortization Expense (Deferred)		9,945,608	0	99,456	0	0	0	[redacted]			0	0	0	
Furnace Replacement Program		0	0	0	0	0		[redacted]			0	0	0	
Ex-Franchise Depreciation & Amortization		0	0	0	0	0		[redacted]			0	0	0	
Total Depreciation & Amortization Expenses		**32,349,802**	**1,169**	**310,926**	**70,338**	**-49,659**	**12,401**	[redacted]			**0**	**1,520**	**0**	
V. CAPITAL & OTHER TAXES								[redacted]						
Municipal Taxes		12,900,000	740	151,385	269,896	42,882	10,029	[redacted]			0	0	0	
Payroll Tax		839,629	61	9,899	7,665	1,218	2,431	[redacted]			0	266	0	
Taxes on Common Assets		93,000	5	871	1,305	227	226	[redacted]			0	1	0	
Corporate Capital Tax		3,286,134	169	30,773	46,112	8,013	7,991	[redacted]			0	29	0	1e
Business Taxes		0	0	0	0	0		[redacted]			0	0	0	
Other		0	0	0	0	0		[redacted]			0	0	0	
Income Taxes		3,192,741	164	29,899	44,801	7,785	7,763	[redacted]			0	28	0	
Total Taxes		**20,311,504**	**1,138**	**222,827**	**369,779**	**60,126**	**28,440**	[redacted]			**0**	**323**	**0**	
VI. FINANCE EXPENSE		**21,603,263**	**1,103**	**200,481**	**303,141**	**52,679**	**52,493**	[redacted]			**0**	**189**	**0**	1e
VII. CORPORATE ALLOCATION		**12,000,000**	**613**	**111,361**	**168,386**	**29,262**	**29,158**	[redacted]			**0**	**105**	**0**	1e
VIII. NET INCOME (LOSS)		**2,894,415**	**148**	**26,861**	**40,615**	**7,058**	**7,033**	[redacted]			**0**	**25**	**0**	1e
COST OF SERVICE SUMMARY								[redacted]						
COST OF GAS		177,264,835	11,820	178,569	[redacted]		190,673	[redacted]			0	44,879	0	1a,2d
OTHER REVENUE		-1,189,728	-41	-6,559	-5,060	-841	-1,771	[redacted]			0	-175	0	1e
OPERATING EXPENSES								[redacted]						
Customer Service & Corporate Relations		30,007,662	1,699	230,247	163,276	49,335	109,014	[redacted]			0	14,617	0	
Operations & Maintenance		16,165,264	1,655	319,244	258,240	17,663	24,612	[redacted]			0	0	0	
Organizational Suport		15,707,672	1,113	180,062	143,396	22,792	45,545	[redacted]			0	4,973	0	1e
Adjustments to Income		-1,330,599	-96	-15,687	-12,147	-1,931	-3,853	[redacted]			0	-421	0	
Sub-total		60,550,000	4,371	713,866	552,765	87,860	175,318	[redacted]			0	19,168	0	
DEPRECIATION & AMORTIZATION		32,349,802	1,169	310,926	70,338	-49,659	12,401	[redacted]			0	1,520	0	1e
CAPITAL & OTHER TAXES		20,311,504	1,138	222,827	369,779	60,126	28,440	[redacted]			0	323	0	1e
FINANCE EXPENSE		21,603,263	1,103	200,481	303,141	52,679	52,493	[redacted]			0	189	0	1e
CORPORATE ALLOCATION		12,000,000	613	111,361	168,386	29,262	29,158	[redacted]			0	105	0	1e
NET INCOME		2,894,415	148	26,861	40,615	7,058	7,033	[redacted]			0	25	0	1e
COST OF SERVICE		325,784,091	20,321	1,758,332	[redacted]		493,745	[redacted]			0	66,034	0	1e

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Revenue of Non-Gas Costs at Existing Rates
2019/20 Test Year

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	Account Description	Total Allocated Dollars	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	FRPGS Fixed Price	
1	DOWNSTREAM REVENUES																
2	FROM CURRENT RATES																
3																	
4	Number of Bills	[redacted]															
5	Basic Monthly Charge				$14.00	$77.00	$1,118.31	$274.06	$2,353.33	$115,409.95	$8,026.07	$1,042.72					
6	Basic Monthly Revenue	58,178,524	[redacted]														
7																	
8	Billing Demand	[redacted]															
9	Monthly Demand Charge				$0.00	$0.00	$149.52	$128.61	$156.26	$0.00	$4.28	$76.80					
10	Monthly Demand Revenue	3,900,839	[redacted]														1d,1e
11																	
12	Billing Volume	[redacted]															
13	Volumetric Charge				$85.22	$34.46	$6.39	$0.00	$0.01	$0.00	$0.09	$2.90					
14	Volumetric Revenue	78,281,763	[redacted]														
15																	
16	Total Downstream Revenue	140,361,127															
17																	
18																	
19																	
20	UPSTREAM REVENUES																
21	FROM CURRENT RATES																
22																	
23																	
24	Billing Demand	[redacted]															
25	Monthly Demand Charge				$0.00	$0.00	$6.18	$9.88	$10.98	$0.00	$0.00	$2.92					
26	Monthly Demand Revenue	104,769	[redacted]														
27																	
28	Billing Volume	[redacted]															
29	Volumetric Charge				$7.11	$7.09	$4.83	$4.53	$4.54	$0.00	$0.00	$4.68	$1.64	$0.78	$1.30	$31.37	
30	Volumetric Revenue	12,041,361	[redacted]														1d,1e
31																	
32	Total Upstream Revenue	12,146,130															
33																	
34																	
35	**TOTAL NON-GAS REVENUES**	**152,524,872**	**0**	**0**	**109,941,344**	**30,132,872**	**6,274,676**	**8,024**	**1,484,485**	**1,385,423**	**236,483**	**845,414**	**2,112,524**	**77,672**	**8,340**	**17,615**	1e
36	**FROM CURRENT RATES**																

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

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BILLED VS. BILLED

	Load Factor	Annual Use 10^3m^3	Mcf	FEB 1/19 APPROVED BILLED RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$222	$390	($14)	-3.4%
		1.98	70	$168	$0	$468	$636	$168	$0	$441	$609	($27)	-4.2%
(Typical Residential Customer)		**2.22**	78	$168	$0	$523	$691	$168	$0	$493	$661	($30)	-4.3%
		2.80	99	$168	$0	$662	$830	$168	$0	$624	$792	($38)	-4.6%
		3.20	113	$168	$0	$755	$923	$168	$0	$712	$880	($43)	-4.7%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$819	$987	($50)	-4.8%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,520	$2,688	($153)	-5.4%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,094	$3,018	$22	0.7%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,995	$11,919	$115	1.0%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$125,651	$126,575	$1,317	1.1%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,097	$70,924	$76,758	$159,779	($8,776)	-5.2%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,097	$44,327	$76,758	$133,183	($16,187)	-10.8%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,097	$73,879	$127,930	$213,906	($26,097)	-10.9%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,097	$147,758	$255,861	$415,715	($50,872)	-10.9%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,097	$323,392	$559,992	$895,480	($109,770)	-10.9%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,097	$657,215	$1,138,047	$1,807,360	($221,715)	-10.9%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,097	$19,056	$61,870	$93,023	($17,951)	-16.2%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,097	$23,641	$76,758	$112,496	($21,952)	-16.3%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,097	$39,402	$127,930	$179,429	($35,705)	-16.6%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,097	$78,804	$255,861	$346,762	($70,088)	-16.8%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,097	$172,476	$559,992	$744,564	($151,826)	-16.9%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,097	$350,515	$1,138,047	$1,500,659	($307,185)	-17.0%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$34,887	$23,685	$70,669	$6,199	9.6%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$147,598	$100,205	$259,900	$30,498	13.3%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$236,157	$160,328	$408,582	$49,590	13.8%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$18,606	$23,685	$54,388	$4,911	9.9%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$78,719	$100,205	$191,021	$25,051	15.1%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$125,950	$160,328	$298,375	$40,875	15.9%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,169	$15,304	$24,100	$42,573	($71)	-0.2%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,169	$21,426	$33,740	$58,334	($51)	-0.1%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,169	$30,608	$48,200	$81,977	($21)	0.0%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,969	$41,168	$276,715	$330,852	($151,980)	-31.5%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,969	$205,840	$1,383,573	$1,602,382	($698,817)	-30.4%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,969	$411,680	$2,767,147	$3,191,796	($1,382,364)	-30.2%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,969	$21,956	$276,715	$311,640	($94,787)	-23.3%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,969	$109,781	$1,383,573	$1,506,324	($412,851)	-21.5%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,969	$219,563	$2,767,147	$2,999,678	($810,430)	-21.3%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,969	$317,782	$4,005,001	$4,335,751	($1,166,136)	-21.2%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$198,034	$9,891	$220,895	($6,031)	-2.7%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$254,616	$12,717	$280,302	($3,391)	-1.2%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$622,394	$31,086	$666,449	$13,769	2.1%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$105,618	$9,891	$128,478	($13,797)	-9.7%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$135,795	$12,717	$161,481	($13,376)	-7.6%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$331,944	$31,086	$375,999	($10,639)	-2.8%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,423	$13,260	$72,282	$97,966	($39,627)	-28.8%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,423	$27,625	$240,941	$280,990	($117,706)	-29.5%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,423	$138,126	$1,204,707	$1,355,256	($588,171)	-30.3%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,423	$4,420	$72,282	$89,126	($32,066)	-26.5%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,423	$14,733	$240,941	$268,098	($106,679)	-28.5%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,423	$73,667	$1,204,707	$1,290,797	($533,039)	-29.2%

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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

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Schedule 11.1.0
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BASE VS. BASE

	Load Factor	Annual Use 10^3m^3	Mcf	FEB 1/19 APPROVED BASE RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$218	$386	($9)	-2.3%
		1.98	70	$168	$0	$450	$618	$168	$0	$432	$600	($18)	-3.0%
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$484	$652	($20)	-3.0%
		2.80	99	$168	$0	$637	$805	$168	$0	$611	$779	($26)	-3.2%
		3.20	113	$168	$0	$727	$895	$168	$0	$698	$866	($29)	-3.3%
		3.68	130	$168	$0	$837	$1,005	$168	$0	$803	$971	($34)	-3.4%
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,470	$2,638	($104)	-3.8%
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,029	$2,953	$56	1.9%
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,654	$11,578	$293	2.6%
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$121,764	$122,688	$3,344	2.8%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$46,995	$91,867	$150,959	($10,246)	-6.4%
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$29,373	$91,870	$133,340	($8,684)	-6.1%
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$48,953	$153,112	$214,162	($13,591)	-6.0%
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$97,906	$306,224	$416,227	($25,860)	-5.8%
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$214,282	$670,220	$896,599	($55,027)	-5.8%
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$435,477	$1,362,060	$1,809,634	($110,463)	-5.8%
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$12,627	$74,049	$98,772	($6,277)	-6.0%
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$15,665	$91,867	$119,629	($7,469)	-5.9%
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$26,108	$153,112	$191,317	($11,567)	-5.7%
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$52,216	$306,224	$370,537	($21,811)	-5.6%
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$114,284	$670,220	$796,601	($46,166)	-5.5%
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$232,254	$1,362,060	$1,606,411	($92,455)	-5.4%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$34,705	$23,920	$70,722	$6,252	9.7%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$146,827	$101,200	$260,124	$30,723	13.4%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$234,924	$161,920	$408,941	$49,950	13.9%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$18,509	$23,920	$54,526	$5,049	10.2%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$78,308	$101,200	$191,605	$25,635	15.4%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$125,293	$161,920	$299,310	$41,809	16.2%
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$15,304	$21,925	$40,398	($83)	-0.2%
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$21,426	$30,695	$55,289	($69)	-0.1%
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$30,608	$43,850	$77,627	($47)	-0.1%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$97,044	$252,968	$362,981	($95,350)	-20.8%
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$485,221	$1,264,838	$1,763,028	($415,668)	-19.1%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$970,442	$2,529,676	$3,513,087	($816,065)	-18.9%
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$51,757	$252,968	$317,694	($64,233)	-16.8%
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$258,785	$1,264,838	$1,536,592	($260,079)	-14.5%
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$517,569	$2,529,676	$3,060,214	($504,887)	-14.2%
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$749,098	$3,661,300	$4,423,367	($723,912)	-14.1%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$197,573	$21,000	$231,542	$4,616	2.0%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$254,022	$27,000	$293,991	$10,298	3.6%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$620,942	$66,000	$699,911	$47,231	7.2%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$105,372	$21,000	$139,341	($2,935)	-2.1%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$135,478	$27,000	$175,447	$590	0.3%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$331,169	$66,000	$410,138	$23,501	6.1%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	($414)	$80,394	$92,404	($38,392)	-29.4%
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	($861)	$267,981	$279,543	($96,496)	-25.7%
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	($4,307)	$1,339,907	$1,348,023	($482,122)	-26.3%
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	($138)	$80,394	$92,680	($21,715)	-19.0%
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	($459)	$267,981	$279,945	($72,175)	-20.5%
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	($2,297)	$1,339,907	$1,350,033	($360,520)	-21.1%

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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 10.1.0

Cost of Service Elements

SGS

	Demand	Energy	Customer	Total
Cost of Gas	30,833,940	1,508,864	0	32,342,804
Other Income	-68,359	-452	-971,167	-1,039,977
Operating & Maintenance Expenses	7,480,011	49,422	36,957,610	44,487,044
Depreciation & Amortization	4,293,438	5,772,166	11,448,390	21,513,995
Capital & Other Taxes	3,915,332	481,214	9,358,475	13,755,021
Finance Expense	3,471,523	1,579,608	9,448,546	14,499,677
Corporate Allocation	1,928,333	877,427	5,248,400	8,054,160
Net Income	465,116	211,637	1,265,921	1,942,673
Total Cost of Service	52,319,335	10,479,887	72,756,175	135,555,397

LGS

	Demand	Energy	Customer	Total
Cost of Gas	23,574,981	1,125,616	0	24,700,597
Other Income	-52,295	-345	-42,140	-94,779
Operating & Maintenance Expenses	5,722,216	37,698	4,337,539	10,097,453
Depreciation & Amortization	2,938,911	3,782,173	2,347,647	9,068,731
Capital & Other Taxes	2,994,007	336,850	1,483,665	4,814,523
Finance Expense	2,653,503	1,105,586	1,574,235	5,333,324
Corporate Allocation	1,473,946	614,122	874,443	2,962,510
Net Income	355,518	148,127	210,917	714,561
Total Cost of Service	39,660,785	7,149,828	10,786,305	57,596,918

HVF

	Demand	Energy	Customer	Total
Cost of Gas	6,583,125	344,193	0	6,927,317
Other Income	-16,483	-103	-9,094	-25,680
Operating & Maintenance Expenses	1,803,632	11,245	960,145	2,775,022
Depreciation & Amortization	837,971	299,213	175,809	1,312,993
Capital & Other Taxes	911,170	60,941	81,436	1,053,547
Finance Expense	806,444	199,814	79,602	1,085,861
Corporate Allocation	447,957	110,991	44,217	603,165
Net Income	108,048	26,771	10,665	145,484
Total Cost of Service	11,481,864	1,053,064	1,342,780	13,877,709

Cooperative

	Demand	Energy	Customer	Total
Cost of Gas	11,535	205	0	11,740
Other Income	-20	0	-20	-40
Operating & Maintenance Expenses	2,146	10	2,117	4,273
Depreciation & Amortization	743	1	428	1,172
Capital & Other Taxes	829	62	263	1,154
Finance Expense	688	204	225	1,117
Corporate Allocation	382	113	125	621
Net Income	92	27	30	150
Total Cost of Service	16,395	624	3,169	20,187

Main Line

	Demand	Energy	Customer	Total
Cost of Gas	112,234	111,897	0	224,131
Other Income	-7,608	-4	-767	-8,380
Operating & Maintenance Expenses	832,509	444	80,931	913,884
Depreciation & Amortization	300,371	99,452	15,830	415,653
Capital & Other Taxes	311,701	6,578	7,772	326,051
Finance Expense	255,820	21,602	7,668	285,091
Corporate Allocation	142,101	11,999	4,260	158,360
Net Income	34,275	2,894	1,027	38,197
Total Cost of Service	1,981,402	254,864	116,721	2,352,987

Special Contract

	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1d
Other Income	-7,072	-1	-86	-7,159	
Operating & Maintenance Expenses	773,792	92	8,563	782,447	
Depreciation & Amortization	-100,015	-8	8,098	-91,924	
Capital & Other Taxes	134,715	13	6,709	141,437	
Finance Expense	105,533	37	6,151	111,721	
Corporate Allocation	58,621	21	3,417	62,058	
Net Income	14,139	5	824	14,968	
Total Cost of Service	[redacted]				1e

Power Station

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income	-564	-2	-194	-760
Operating & Maintenance Expenses	61,728	181	17,129	79,038
Depreciation & Amortization	-96,972	-15	43,729	-53,258
Capital & Other Taxes	18,468	25	37,805	56,298
Finance Expense	14,592	73	34,897	49,562
Corporate Allocation	8,105	41	19,384	27,530
Net Income	1,955	10	4,675	6,640
Total Cost of Service	[redacted]			

Interruptible

	Demand	Energy	Customer	Total	
Cost of Gas	690,449	190,673	0	881,122	1d
Other Income	-1,578	-25	-1,629	-3,232	
Operating & Maintenance Expenses	172,679	2,739	171,800	347,217	
Depreciation & Amortization	63,730	166	34,224	98,119	
Capital & Other Taxes	89,063	10,639	16,482	116,185	
Finance Expense	78,766	34,848	16,333	129,948	
Corporate Allocation	43,753	19,357	9,073	72,182	
Net Income	10,553	4,669	2,188	17,410	
Total Cost of Service	1,147,415	263,065	248,471	1,658,951	1e

Primary Gas

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Supplemental Gas - Firm

	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1a
Other Income					
Operating & Maintenance Expenses					
Depreciation & Amortization					1e
Capital & Other Taxes					
Finance Expense					
Corporate Allocation					
Net Income					
Total Cost of Service					1e

Supplemental Gas - Interruptible

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Fixed Price Offering

	Demand	Energy	Customer	Total	
					1a
Cost of Gas	0	44,879	0	44,879	
Other Income	0	-4	-171	-175	
Operating & Maintenance Expenses	0	419	18,750	19,168	
Depreciation & Amortization	0	33	1,486	1,520	1e
Capital & Other Taxes	0	19	304	323	
Finance Expense	0	43	146	189	
Corporate Allocation	0	24	81	105	
Net Income	0	6	20	25	
Total Cost of Service	0	45,418	20,616	66,034	1e

Unassigned

	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total

	Demand	Energy	Customer	Total
Cost of Gas	61,836,486	115,428,348	0	177,264,835
Other Income	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	8,238,176	10,035,983	14,075,643	32,349,802
Capital & Other Taxes	8,375,286	943,305	10,992,913	20,311,504
Finance Expense	7,386,869	3,048,590	11,167,803	21,603,263
Corporate Allocation	4,103,197	1,693,405	6,203,398	12,000,000
Net Income	989,696	408,451	1,496,267	2,894,415
Total Cost of Service	107,624,446	132,694,307	85,465,338	325,784,091

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 10.1.1

	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1 REVENUE REQUIREMENTS		[redacted]													
2 Upstream Demand ($)															
3 Upstream Commodity ($)															
4 Upstream Customer ($)															
5 Upstream Total ($)															
6															
7 Downstream Demand ($)															1e
8 Downstream Commodity ($)															
9 Downstream Customer ($)															
10 Downstream Total ($)															
11															
12 Total (incl. gas costs)															
13															
14															
15 MONTHLY BILLING DETERMINANTS															
16 Upstream Demand (10^3m^3-day)		[redacted]													
17 Upstream Commodity (10^3m^3)															
18 Upstream Customer (customers)															
19															
20 Downstream Demand (10^3m^3-day)															1d
21 Downstream Commodity (10^3m^3)															
22 Downstream Customer (customers)															
23															
24 PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25															
26 RESULTING UNIT CHARGES															
27 Upstream Demand ($/10^3m^3$-day)		454.726	0.000	0.000	295.043	470.592	422.296	0.000	0.000	149.285	0.000	0.000	0.000	0.000	
28 Upstream Commodity ($/10^3m^3$)		80.314	49.715	48.053	15.160	2.310	2.509	0.000	0.000	8.050	76.908	134.897	134.294	80.883	
29 Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30															
31 Downstream Demand ($/10^3m^3$-day)		248.552	0.000	0.000	188.524	175.835	242.976	61.538	0.806	90.523	0.000	0.000	0.000	0.000	
32 Downstream Commodity ($/10^3m^3$)		7.252	42.302	38.565	10.218	0.000	1.518	0.096	18.305	6.445	0.000	0.000	0.000	0.000	
33 Downstream Customer ($/customer)		24.749	21.707	108.165	1,008.093	264.053	1,080.749	2,806.285	6,559.405	1,035.295	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 10.1.2

Gas Costs vs. Non-Gas Costs

		ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,638,042	30,756,386	23,515,600	6,564,891	11,505	101,088	0	0	688,573	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,301,940	1,148,631	878,216	245,173	430	3,775	0	0	25,716	0	0	0	0	
5	Total	Total	63,939,983	31,905,017	24,393,815	6,810,064	11,935	104,863	0	0	714,288	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]			44,879	
9	Non-gas Costs	Non-gas Costs	3,663,952	1,082,974	856,047	300,482	419	6,588	0	0	71,841				539	1a,1e
10	Total	Total	117,614,218	2,024,254	1,575,190	514,603	624	10,585	0	0	119,139				45,418	
11			0	0	0	0	0	0	0	0	0				0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,588,308	31,697,666	24,234,743	6,779,012	11,711	105,085	0	0	735,872	[redacted]			44,879	
19	Total Non-gas Costs	Total Non-gas Costs	5,965,892	2,231,605	1,734,263	545,655	848	10,363	0	0	97,556				539	1e
20	Total Upstream Costs	Total Upstream Costs	181,554,200	33,929,271	25,969,006	7,324,666	12,559	115,448	0	0	833,428				45,418	
21			0	0	0	0	0	0	0	0	0				0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	198,444	77,554	59,381	18,234	29	11,146	[redacted]		1,876	0	0	0	0	
24	Non-gas Costs	Non-gas Costs	43 486 019	20 336 764	15 207 589	4 653 567	4 430	1 865 393	979,714	7,311	431 250	0	0	0	0	2d,1e
25	Total	Total	43,684,463	20,414,318	15,266,970	4,671,801	4,460	1,876,540	[redacted]		433,127	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]		143,374	0	0	0	0	
29	Non-gas Costs	Non-gas Costs	13,602,006	7,888,049	5,168,165	408,390	0	136,378	159	313	552	0	0	0	0	2d,1e
30	Total	Total	15,080,089	8,455,633	5,574,638	538,461	0	244,278	[redacted]		143,926	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	33,675	157,426	248,471	0	0	0	20,616	2d,1e
35	Total	Total	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]		248,471	0	0	0	20,616	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,676,527	645,137	465,854	148,306	29	119,046	[redacted]		145,250	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	142,553,363	100,980,988	31,162,059	6,404,737	7,599	2,118,493	1,013,549	165,049	680,273	0	0	0	20,616	2d,1e
40	Total Downstream Costs	Total Downstream Costs	144,229,890	101,626,126	31,627,913	6,553,042	7,628	2,237,539	[redacted]		825,523	0	0	0	20,616	
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	32,342,804	24,700,597	6,927,317	11,740	224,131	[redacted]		881,122	[redacted]			44,879	
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	148,519,256	103,212,593	32,896,322	6,950,392	8,447	2,128,856	1,013,549	165,049	777,829				21,155	2d,1e
44	Grand Total	Grand Total	325,784,091	135,555,397	57,596,918	13,877,709	20,187	2,352,987	[redacted]		1,658,951				66,034	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 10.1.1, line 17, PG column)
49 0.91 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR 21,155 (lines 9 & 34, FPO column) 1e
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column)
37.67 per 10^3m^3

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 10.1.3

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION																
2	Demand	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
3	Energy	113,369,822	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
4	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
5	Total	113,369,822	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
6																	
7	PIPELINE																
8	Demand	44,875,222	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
9	Energy	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
10	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
11	Total	44,875,222	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
12																	
13	STORAGE																
14	Demand	19,064,760	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
15	Energy	4,244,395	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
16	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
17	Total	23,309,156	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
18																	
19	TRANSMISSION																
20	Demand	17,108,649	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
21	Energy	15,080,089	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
22	Customer	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1a
23	Total	32,188,738	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
24																	
25	DISTRIBUTION																
26	Demand	26,575,814	10,743,211	2,053,884	12,797,095	9,786,354	2,973,551	1,930	727,100	[redacted]	[redacted]	289,784	[redacted]	[redacted]	[redacted]	0	
27	Energy	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	2d,1e
28	Customer	11,024,589	10,001,064	700,104	10,701,168	318,376	4,253	2	20	[redacted]	[redacted]	766	[redacted]	[redacted]	[redacted]	0	
29	Total	37,600,403	20,744,275	2,753,988	23,498,263	10,104,729	2,977,804	1,932	727,120	[redacted]	[redacted]	290,550	[redacted]	[redacted]	[redacted]	0	
30																	
31	ONSITE																
32	Demand	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	
33	Energy	0	0	0	0	0	0	0		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	0	2d,1e
34	Customer	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]	[redacted]	247,705	[redacted]	[redacted]	[redacted]	20,616	
35	Total	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]	[redacted]	247,705	[redacted]	[redacted]	[redacted]	20,616	
36																	
37	TOTAL SERVICE																
38	Demand	107,624,446	43,875,906	8,443,429	52,319,335	39,660,785	11,481,864	16,395	1,981,402	[redacted]	[redacted]	1,147,415	[redacted]	[redacted]	[redacted]	0	
39	Energy	132,694,307	8,027,388	2,452,499	10,479,887	7,149,828	1,053,064	624	254,864	[redacted]	[redacted]	263,065	[redacted]	[redacted]	[redacted]	45,418	2d,1e
40	Customer	85,465,338	65,662,001	7,094,174	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]	[redacted]	248,471	[redacted]	[redacted]	[redacted]	20,616	
41	Total	325,784,091	117,565,295	17,990,102	135,555,397	57,596,918	13,877,709	20,187	2,352,987	[redacted]	[redacted]	1,658,951	[redacted]	[redacted]	[redacted]	66,034	

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Rate Base
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 10.1.4
Page 1 of 4

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
RATE BASE DETAILS											
I. GAS PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Franchises & Consents	401	22,384		0	22,384		13,227	1,955	15,182	5,269	1,179
Other Intangible Plant	402	13,614,400		0	13,614,400		8,044,772	1,189,187	9,233,958	3,204,458	717,204
Sub-total	401-402	13,636,784		0	13,636,784		8,057,998	1,191,142	9,249,140	3,209,727	718,383
B. PRODUCTION PLANT											
(Reserved)	-	0		0	0		0	0	0	0	0
Sub-total	420-424	0		0	0		0	0	0	0	0
C. LOCAL STORAGE PLANT											
Land	440	0		0	0		0	0	0	0	0
Structures & Improvements	442	0		0	0		0	0	0	0	0
Sub-total	440-449	0		0	0		0	0	0	0	0
D. TRANSMISSION PLANT											
Land	460	1,027,343		0	1,027,343		382,578	73,131	455,708	348,597	106,186
Structures & Improvements	461	76,420		0	76,420		25,075	4,791	29,866	22,867	7,022
Structures & Improvements - M&R	463	1,363,403		0	1,363,403		447,356	85,473	532,829	407,974	125,278
Mains	465	155,008,042		3,738,000	151,270,042		58,428,531	11,169,202	69,597,733	53,234,682	16,204,102
Measuring & Reg. Equipment	467	14,466,096		0	14,466,096		4,746,577	906,894	5,653,471	4,328,723	1,329,232
Other Transmission Equipment	469	0		0	0		0	0	0	0	0
Sub-total	460-469	171,941,305		3,738,000	168,203,305		64,030,117	12,239,490	76,269,607	58,342,843	17,771,819
E. DISTRIBUTION PLANT											
Land	470	1,764,150		0	1,764,150		1,138,749	161,219	1,299,968	369,417	70,597
Computer Equipment - Hardware	471	1,180,367		0	1,180,367		761,920	107,869	869,789	247,172	47,236
Structures & Improvements	472	1,377,038		0	1,377,038		572,552	109,469	682,021	521,480	158,230
Structures & Improvements: M & R	472.1	5,596,871		0	5,596,871		2,173,126	415,409	2,588,535	1,980,008	602,855
Services	473	284,239,631		0	284,239,631		227,894,619	30,429,150	258,323,769	24,635,436	962,180
Regulators	474	56,621,401		0	56,621,401		29,755,325	5,699,896	35,455,221	19,792,703	1,059,822
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	231,880,662		0	231,880,662		134,392,823	17,197,517	151,590,340	60,773,793	17,792,851
Measuring & Reg. Equipment	477	52,283,320		0	52,283,320		19,479,624	3,723,669	23,203,293	17,748,539	5,403,911
Telemetry Equipment	477.1	5,363,336		0	5,363,336		2,082,450	398,075	2,480,526	1,897,390	577,700
Meters	478	46,179,936		0	46,179,936		24,268,191	4,648,787	28,916,978	16,142,761	864,382
AMR/ERT Modules	479	1,703,806		0	1,703,806		1,703,806	0	1,703,806	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	688,190,519		0	688,190,519		444,223,186	62,891,059	507,114,245	144,108,699	27,539,764
F. GENERAL PLANT											
Land	480	136,000		0	136,000		90,468	9,453	99,921	22,680	6,233
Structures & Improvements	482	8,619,031		0	8,619,031		5,733,450	599,088	6,332,539	1,437,329	395,012
Leasehold Improvements	482.1	0		0	0		0	0	0	0	0
Office Furniture & Equipment	483	0		0	0		0	0	0	0	0
Target Adjustments	483.1	0		0	0		0	0	0	0	0
Computer Equipment: Software	483.2	0		0	0		0	0	0	0	0
Computer System Development	483.3	0		0	0		0	0	0	0	0
Transportation Equipment	484	-655		0	-655		-436	-46	-481	-109	-30
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	185,134		0	185,134		107,303	15,971	123,274	44,678	10,330
Tools & Work Equipment	486	188		0	188		109	16	125	45	10
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Deferred Ineligible Overhead	488	3,849,973		0	3,849,973		2,561,034	267,602	2,828,636	642,030	176,445
Property, Plant & Equipment Gas Inventory	489	297,209		0	297,209		179,102	25,859	204,961	67,561	14,872
Sub-total	480-490	13,086,880		0	13,086,880		8,671,031	917,944	9,588,975	2,214,213	602,872
Sub-total Plant-in-Service		886,855,489		3,738,000	883,117,489		524,982,332	77,239,635	602,221,967	207,875,481	46,632,839
G. ADDITIONS TO UTILITY PLANT											
Construction Work in Progress		0		0	0		0	0	0	0	0
Other Additions		0		0	0		0	0	0	0	0
Sub-total		0		0	0		0	0	0	0	0
Total Utility Plant		**886,855,489**		**3,738,000**	**883,117,489**		**524,982,332**	**77,239,635**	**602,221,967**	**207,875,481**	**46,632,839**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-5,220,747		0	-5,220,747		-3,109,938	-457,251	-3,567,189	-1,190,207	-274,724
Production Plant		0		0	0		0	0	0	0	0
Local Storage Plant		0		0	0		0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO
RATE BASE DETAILS												
I. GAS PLANT IN SERVICE												
A. INTANGIBLE PLANT												
Franchises & Consents	401	22,384	1	392	168	70	124	0	0	0	0	0
Other Intangible Plant	402	13,614,400	795	238,399	101,951	42,347	75,289	0	0	0	0	0
Sub-total	401-402	13,636,784	796	238,791	102,118	42,416	75,412	0	0	0	0	0
B. PRODUCTION PLANT												
(Reserved)	-	0	0	0	0	0	0	0	0	0	0	0
Sub-total	420-424	0	0	0	0	0	0	0	0	0	0	0
C. LOCAL STORAGE PLANT												
Land	440	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	442	0	0	0	0	0	0	0	0	0	0	0
Sub-total	440-449	0	0	0	0	0	0	0	0	0	0	0
D. TRANSMISSION PLANT												
Land	460	1,027,343	171	64,343	36,605	5,248	10,486	0	0	0	0	0
Structures & Improvements	461	76,420	11	4,292	11,299	340	723	0	0	0	0	0
Structures & Improvements - M&R	463	1,363,403	200	76,580	201,586	6,065	12,890	0	0	0	0	0
Mains	465	155,008,042	26,053	9,811,016	3,738,000	802,326	1,594,131	0	0	0	0	0
Measuring & Reg. Equipment	467	14,466,096	2,120	812,538	2,138,889	64,352	136,772	0	0	0	0	0
Other Transmission Equipment	469	0	0	0	0	0	0	0	0	0	0	0
Sub-total	460-469	171,941,305	28,554	10,768,770	6,126,379	878,331	1,755,001	0	0	0	0	0
E. DISTRIBUTION PLANT												
Land	470	1,764,150	56	11,004	807	4,607	7,694	0	0	0	0	0
Computer Equipment - Hardware	471	1,180,367	37	7,363	540	3,082	5,148	0	0	0	0	0
Structures & Improvements	472	1,377,038	0	0	0	0	15,306	0	0	0	0	0
Structures & Improvements: M & R	472.1	5,596,871	969	365,114	0	0	59,391	0	0	0	0	0
Services	473	284,239,631	0	112,363	0	0	205,884	0	0	0	0	0
Regulators	474	56,621,401	0	95,980	0	0	217,675	0	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0	0
Mains	475	231,880,662	0	0	0	0	1,723,679	0	0	0	0	0
Measuring & Reg. Equipment	477	52,283,320	19,686	3,272,835	313,332	1,789,355	532,369	0	0	0	0	0
Telemetry Equipment	477.1	5,363,336	929	349,879	0	0	56,912	0	0	0	0	0
Meters	478	46,179,936	0	78,281	0	0	177,534	0	0	0	0	0
AMR/ERT Modules	479	1,703,806	0	0	0	0	0	0	0	0	0	0
Other Distribution Equipment	-	0	0	0	0	0	0	0	0	0	0	0
Sub-total	470-479	688,190,519	21,677	4,292,819	314,678	1,797,044	3,001,592	0	0	0	0	0
F. GENERAL PLANT												
Land	480	136,000	10	2,053	1,757	178	780	2,051	277	18	0	43
Structures & Improvements	482	8,619,031	608	130,087	111,378	11,251	49,425	129,969	17,574	1,131	0	2,729
Leasehold Improvements	482.1	0	0	0	0	0	0	0	0	0	0	0
Office Furniture & Equipment	483	0	0	0	0	0	0	0	0	0	0	0
Target Adjustments	483.1	0	0	0	0	0	0	0	0	0	0	0
Computer Equipment: Software	483.2	0	0	0	0	0	0	0	0	0	0	0
Computer System Development	483.3	0	0	0	0	0	0	0	0	0	0	0
Transportation Equipment	484	-655	0	-10	-8	-1	-4	-10	-1	0	0	0
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	185,134	12	3,602	1,586	577	1,076	0	0	0	0	0
Tools & Work Equipment	486	188	0	4	2	1	1	0	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0	0
Deferred Ineligible Overhead	488	3,849,973	272	58,108	49,751	5,025	22,077	58,055	7,850	505	0	1,219
Property, Plant & Equipment Gas Inventory	489	297,209	17	5,077	2,225	926	1,571	0	0	0	0	0
Sub-total	480-490	13,086,880	918	198,920	166,691	17,957	74,926	190,065	25,699	1,654	0	3,990
Sub-total Plant-in-Service		886,855,489	51,945	15,499,301	6,709,867	2,735,749	4,906,932	190,065	25,699	1,654	0	3,990
G. ADDITIONS TO UTILITY PLANT												
Construction Work in Progress		0	0	0	0	0	0	0	0	0	0	0
Other Additions		0	0	0	0	0	0	0	0	0	0	0
Sub-total		0	0	0	0	0	0	0	0	0	0	0
Total Utility Plant		**886,855,489**	**51,945**	**15,499,301**	**6,709,867**	**2,735,749**	**4,906,932**	**190,065**	**25,699**	**1,654**	**0**	**3,990**
II. ACCUMULATED DEPRECIATION												
Intangible Plant		-5,220,747	-344	-96,927	-42,394	-20,396	-28,566	0	0	0	0	0
Production Plant		0	0	0	0	0	0	0	0	0	0	0
Local Storage Plant		0	0	0	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
Transmission Plant		-41,188,559		0	-41,188,559		-15,285,966	-2,921,917	-18,207,883	-13,928,464	-4,252,406
Distribution Plant		-228,870,742		0	-228,870,742		-147,087,437	-20,694,528	-167,781,964	-47,345,031	-9,919,667
General Plant		-7,482,792		0	-7,482,792		-4,935,131	-535,195	-5,470,326	-1,357,026	-364,650
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-282,762,840		0	-282,762,840		-170,418,471	-24,608,892	-195,027,363	-63,820,728	-14,811,446
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-282,762,840**		**0**	**-282,762,840**		**-170,418,471**	**-24,608,892**	**-195,027,363**	**-63,820,728**	**-14,811,446**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-61,613,212		0	-61,613,212		-24,853,540	-4,598,287	-29,451,827	-20,397,167	-6,033,161
Cash Working Capital		13,933,390		0	13,933,390		6,413,343	938,385	7,351,728	2,669,244	589,351
Security Deposits		-900,000		0	-900,000		-723,624	-50,656	-774,280	-102,995	-17,517
Gas in Storage		33,138,755		0	33,138,755		13,001,916	2,442,022	15,443,938	12,229,506	4,326,060
Investment in DSM		53,559,521		0	53,559,521		23,030,594	8,033,928	31,064,522	20,352,618	1,606,786
Investment in Regulatory Costs		2,847,151		0	2,847,151		1,893,948	197,899	2,091,847	474,797	130,486
Investment in Site Restoration		1,608,420		0	1,608,420		969,254	139,942	1,109,196	365,622	80,481
Total Other Rate Base		**42,574,026**		**0**	**42,574,026**		**19,731,891**	**7,103,234**	**26,835,125**	**15,591,626**	**682,485**
TOTAL RATE BASE		**646 666 675**		**3 738 000**	**642 928 675**		**374 295 752**	**59 733 977**	**434 029 729**	**159 646 379**	**32 503 878**

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO
Transmission Plant		-41,188,559	-6,817	-2,589,712	-1,569,704	-214,152	-419,422	0	0	0	0	0
Distribution Plant		-228,870,742	-9,427	-1,872,340	-132,813	-758,457	-1,051,043	0	0	0	0	0
General Plant		-7,482,792	-496	-83,586	-27,764	-6,134	-45,398	-109,375	-14,789	-952	0	-2,296
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0	0
Sub-total		-282,762,840	-17,083	-4,642,565	-1,772,675	-999,138	-1,544,429	-109,375	-14,789	-952	0	-2,296
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-282,762,840**	**-17,083**	**-4,642,565**	**-1,772,675**	**-999,138**	**-1,544,429**	**-109,375**	**-14,789**	**-952**	**0**	**-2,296**
III. OTHER RATE BASE												
Contributions in Aid of Construction		-61,613,212	-8,499	-3,161,078	-1,700,192	-263,571	-597,717	0	0	0	0	0
Cash Working Capital		13,933,390	830	138,102	58,553	2,117	65,671	2,670,416	361,076	23,240	0	3,063
Security Deposits		-900,000	-158	-1,420	-158	-316	-3,156	0	0	0	0	0
Gas in Storage		33,138,755	6,110	95,453	0	0	1,037,688	0	0	0	0	0
Investment in DSM		53,559,521	0	535,595	0	0	0	0	0	0	0	0
Investment in Regulatory Costs		2,847,151	201	42,972	36,792	3,716	16,327	42,933	5,805	374	0	901
Investment in Site Restoration		1,608,420	92	27,473	12,043	5,013	8,500	0	0	0	0	0
Total Other Rate Base		**42,574,026**	**-1,424**	**-2,322,904**	**-1,592,962**	**-253,041**	**527,313**	**2,713,349**	**366,881**	**23,613**	**0**	**3,964**
TOTAL RATE BASE		**646,666,675**	**33,438**	**8,533,832**	**3,344,230**	**1,483,569**	**3,889,816**	**2,794,038**	**377,791**	**24,316**	**0**	**5,658**

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	
COST OF SERVICE DETAILS												
I. COST OF GAS												
A. FIXED COSTS												
TCPL FS Demand - Sask Zone		[redacted]		[redacted]			[redacted]					
TCPL STS Demand												
[redacted]												
TCPL Firm Service - Emerson to Man Zone												
TCPL FS Demand - Man Zone												
Other Pipeline Fixed Tolls												
ANR Storage Deliverability												
ANR Joliet to Storage Winter												
ANR Crystal Falls from Storage												
GLGT Storage to Deward												1a
Seasonal Storage Capacity												
Seasonal Storage Deliverability												
Annual Storage Capacity												
Annual Storage Deliverability												
ANR Joliet to Storage Summer												
ANR Crystal Falls to Storage												
GLGT Emerson to Crystal Falls												
Forecast Capacity Management Revenues												
Sub-total												
B. VARIABLE TRANSPORTATION												
TCPL FS - Sask Zone												
TCPL FS - Flowing directly to Man Zone												
TCPL FS - SSDA (Welwyn)												
Firm Service - Emerson to Man Zone												
GLGT Storage Transportation												
ANR Storage Transportation												
ANR Storage Withdrawl Chg.												
Storage Gas - Transportation & Delivery Cost												1a
Compressor Fuel: TCPL SSDA												
Compressor Fuel: Primary												
Compressor Fuel: Emerson												
Compressor Fuel: TCPL SSDA (Welwyn) to MDA												
Compressor Fuel: Oklahoma												
Compressor Fuel: Storage & Supplemental US Supplies												
Sub-total												
C. COMMODITY COST												
Primary Direct to System												
Storage Gas: Primary to System												
Oklahoma Supply												
Storage Gas: Supplemental Supply												
Emerson Supply												1a
Delivered Service												
Fixed Price Offering												
Sub-total												
D. OTHER GAS COSTS												
Minell Charges												
Load Balancing Charges												1a
Baseload Volume Price Increment Charges												
Sub-total												
Total Cost of Gas		**177,264,835**		**0**	**177,264,835**		**27,152,355**	**5,190,449**	**32,342,804**	**24,700,597**	**6,927,317**	
II. OTHER REVENUE												
Rental Income		0		0	0		0	0	0	0	0	
Late Payment Charge		-618,595		0	-618,595		-578,125	-40,470	-618,595	0	0	
Broker Revenue		-17,774		0	-17,774		-13,294	-1,527	-14,821	-2,500	-320	
Other		-553,358		0	-553,358		-368,098	-38,463	-406,561	-92,279	-25,361	
Total Other Revenue		**-1,189,728**		**0**	**-1,189,728**		**-959,517**	**-80,460**	**-1,039,977**	**-94,779**	**-25,680**	

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
COST OF SERVICE DETAILS														
I. COST OF GAS														
A. FIXED COSTS		[redacted]												
TCPL FS Demand - Sask Zone														
TCPL STS Demand														
[redacted]														
TCPL Firm Service - Emerson to Man Zone														
TCPL FS Demand - Man Zone														
Other Pipeline Fixed Tolls														
ANR Storage Deliverability														
ANR Joliet to Storage Winter														
ANR Crystal Falls from Storage														
GLGT Storage to Deward														1a
Seasonal Storage Capacity														
Seasonal Storage Deliverability														
Annual Storage Capacity														
Annual Storage Deliverability														
ANR Joliet to Storage Summer														
ANR Crystal Falls to Storage														
GLGT Emerson to Crystal Falls														
Forecast Capacity Management Revenues														
Sub-total														
B. VARIABLE TRANSPORTATION		[redacted]												
TCPL FS - Sask Zone														
TCPL FS - Flowing directly to Man Zone														
TCPL FS - SSDA (Welwyn)														
Firm Service - Emerson to Man Zone														
GLGT Storage Transportation														
ANR Storage Transportation														
ANR Storage Withdrawl Chg.														
Storage Gas - Transportation & Delivery Cost														1a
Compressor Fuel: TCPL SSDA														
Compressor Fuel: Primary														
Compressor Fuel: Emerson														
Compressor Fuel: TCPL SSDA (Welwyn) to MDA														
Compressor Fuel: Oklahoma														
Compressor Fuel: Storage & Supplemental US Supplies														
Sub-total														
C. COMMODITY COST		[redacted]												
Primary Direct to System														
Storage Gas: Primary to System														
Oklahoma Supply														
Storage Gas: Supplemental Supply														
Emerson Supply														1a
Delivered Service														
Fixed Price Offering														
Sub-total														
D. OTHER GAS COSTS														
Minell Charges														
Load Balancing Charges														1a
Baseload Volume Price Increment Charges														
Sub-total														
Total Cost of Gas		**177,264,835**	**11,740**	**224,131**	[redacted]		**881,122**	[redacted]			**0**	**44,879**	**0**	1a,2d
II. OTHER REVENUE														
Rental Income		0	0	0	0	0					0	0	0	
Late Payment Charge		-618,595	0	0	0	0					0	0	0	
Broker Revenue		-17,774	-1	-28	-8	-38	-59				0	0	0	1e
Other		-553,358	-39	-8,352	-7,151	-722	-3,173				0	-175	0	
Total Other Revenue		**-1,189,728**	**-40**	**-8,380**	**-7,159**	**-760**	**-3,232**				**0**	**-175**	**0**	

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Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
III. OPERATING & ADMINISTRATIVE EXPENSES											
A. CUSTOMER SERVICE & CORPORATE RELATIONS											
Back/Middle Office Services		294,425		0	294,425		45,098	8,621	53,719	41,026	11,506
Billing & Collections		7,705,172		1,572,397	6,132,775		6,267,453	502,418	6,769,871	780,447	119,366
Customer & Public Relations		4,008,554		0	4,008,554		2,593,005	185,072	2,778,077	660,256	431,167
Customer Information Systems (Banner)		533,983		0	533,983		484,409	33,910	518,319	15,421	206
Customer Inspections		7,151,177		2,391,625	4,759,551		6,212,904	456,863	6,669,767	307,762	52,659
Customer Safety Services		1,285,355		0	1,285,355		842,537	58,980	901,517	377,325	5,021
Dispatch		2,306,190		0	2,306,190		1,809,546	239,158	2,048,703	247,197	7,868
Energy Supply, Planning & Support		2,869,025		218,679	2,650,347		806,337	154,165	960,501	734,614	268,875
Environment		398,798		0	398,798		190,956	27,744	218,700	110,456	33,022
Meter Reading		2,511,105		0	2,511,105		2,011,022	165,165	2,176,187	316,691	13,997
Rate and Regulatory Affairs		943,878		0	943,878		627,876	65,607	693,482	157,403	43,258
Sub-total		30,007,662		4,182,701	25,824,961		21,891,142	1,897,702	23,788,844	3,748,597	986,947
B. OPERATIONS AND MAINTENANCE											
Communication System		135,343		0	135,343		21,782	4,163	25,946	19,850	65,936
Distribution Maintenance		6,758,662		0	6,758,662		3,895,538	661,789	4,557,326	1,502,830	341,213
Load Forecast		70,288		0	70,288		32,845	2,299	35,144	17,694	13,545
Metering		573,718		0	573,718		401,250	28,089	429,339	81,856	48,194
Plant Failures & Emergencies		302,792		0	302,792		198,477	13,894	212,371	88,887	1,183
Quality Assessment		434,989		0	434,989		247,076	42,076	289,152	97,850	22,568
Regulating Station Maintenance		5,376,364		426,161	4,950,203		2,819,955	383,912	3,203,867	1,443,380	427,600
System Performance & Reliability		2,513,109		0	2,513,109		1,203,350	174,832	1,378,183	696,060	208,095
Sub-total		16,165,264		426,161	15,739,104		8,820,273	1,311,054	10,131,328	3,948,407	1,128,335
C. ORGANIZATIONAL SUPPORT											
Corporate Governance		2,156,541		0	2,156,541		1,437,745	150,509	1,588,253	362,525	99,671
Corporate Infrastructure		4,581,302		0	4,581,302		3,047,520	318,435	3,365,955	763,988	209,962
Corporate Services		1,864,893		0	1,864,893		1,240,542	129,624	1,370,167	310,994	85,469
Departmental Support		5,446,970		0	5,446,970		3,623,369	378,606	4,001,975	908,349	249,636
Operational Management		1,657,966		0	1,657,966		1,102,893	115,241	1,218,134	276,486	75,985
Sub-total		15,707,672		0	15,707,672		10,452,069	1,092,415	11,544,484	2,622,342	720,722
D. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		852,395		0	852,395		567,020	59,248	626,268	142,147	39,065
Depreciation, Interest, Taxes		-2,182,994		0	-2,182,994		-1,452,145	-151,735	-1,603,880	-364,041	-100,047
Sub-total		-1,330,599		0	-1,330,599		-885,125	-92,487	-977,612	-221,894	-60,982
Total Operating & Administrative Expenses		**60,550,000**		**4,608,862**	**55,941,138**		**40,278,359**	**4,208,685**	**44,487,044**	**10,097,453**	**2,775,022**

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Cost of Service Elements
2019/20 Test Year

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Schedule 10.1.5
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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
III. OPERATING & ADMINISTRATIVE EXPENSES														
A. CUSTOMER SERVICE & CORPORATE RELATIONS								[redacted]						
Back/Middle Office Services		294,425	19	372	117	136	1,463				0	75	0	
Billing & Collections		7,705,172	1,075	9,678	1,075	2,151	21,507				0	0	0	
Customer & Public Relations		4,008,554	0	35,014	4,002	8,003	78,030				0	14,005	0	
Customer Information Systems (Banner)		533,983	0	0	0	0					0	0	0	
Customer Inspections		7,151,177	95	31,155	81,687	2,486	5,565				0	0	0	
Customer Safety Services		1,285,355	45	407	45	90	905				0	0	0	1e
Dispatch		2,306,190	0	1,405	0	0	1,017				0	0	0	
Energy Supply, Planning & Support		2,869,025	354	152,618	102,939	31,816	22,884				0	238	0	
Environment		398,798	23	8,975	23,624	711	3,287				0	0	0	
Meter Reading		2,511,105	0	1,380	153	307	2,390				0	0	0	
Rate and Regulatory Affairs		943,878	67	14,246	12,197	1,232	5,413				0	299	0	
Sub-total		30,007,662	1,679	255,250	225,841	46,932	142,499				0	14,617	0	
B. OPERATIONS AND MAINTENANCE														
Communication System		135,343	10	8,529	2,541	1,139	11,391				0	0	0	
Distribution Maintenance		6,758,662	289	112,554	203,986	6,137	34,328				0	0	0	
Load Forecast		70,288	0	1,098	122	244	2,441				0	0	0	
Metering		573,718	434	3,908	434	868	8,684				0	0	0	
Plant Failures & Emergencies		302,792	11	96	11	21	213				0	0	0	1e
Quality Assessment		434,989	20	7,824	14,855	447	2,274				0	0	0	
Regulating Station Maintenance		5,376,364	688	258,656	0	3	42,170				0	0	0	
System Performance & Reliability		2,513,109	148	56,555	148,873	4,479	20,716				0	0	0	
Sub-total		16,165,264	1,599	449,220	370,821	13,339	122,216				0	0	0	
C. ORGANIZATIONAL SUPPORT														
Corporate Governance		2,156,541	132	24,970	27,868	2,815	12,425				0	683	0	
Corporate Infrastructure		4,581,302	323	69,146	59,201	5,980	26,271				0	1,450	0	
Corporate Services		1,864,893	132	28,147	24,099	2,434	10,694				0	590	0	
Departmental Support		5,446,970	384	82,211	70,388	7,110	31,235				0	1,724	0	1e
Operational Management		1,657,966	117	25,024	21,425	2,164	9,507				0	525	0	
Sub-total		15,707,672	1,088	229,498	202,980	20,504	90,132				0	4,973	0	
D. ADJUSTMENTS TO INCOME														
Corporate Alloc. & Adj.		852,395	60	12,865	11,015	1,113	4,888				0	270	0	
Depreciation, Interest, Taxes		-2,182,994	-154	-32,948	-28,209	-2,850	-12,518				0	-691	0	1e
Sub-total		-1,330,599	-94	-20,083	-17,194	-1,737	-7,630				0	-421	0	
Total Operating & Administrative Expenses		**60,550,000**	**4,273**	**913,884**	**782,447**	**79,038**	**347,217**				**0**	**19,168**	**0**	1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Cost of Service Elements
2019/20 Test Year

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		17,180,097		0	17,180,097		9,787,375	1,499,870	11,287,245	4,429,769	870,008
Amortization of Cust. Contributions		-1,130,083		0	-1,130,083		-149,760	41,573	-108,187	-323,983	-158,974
Depreciation: Common Assets		4,547,217		0	4,547,217		3,024,846	316,066	3,340,912	758,304	208,400
Amortization Expense (Deferreds)		1,806,963		0	1,806,963		1,067,737	157,834	1,225,571	425,310	95,190
Demand Side Management Amortization Expense (Deferred)		9,945,608		0	9,945,608		4,276,611	1,491,841	5,768,452	3,779,331	298,368
Furnace Replacement Program		0		0	0		0	0	0	0	0
Ex-Franchise Depreciation & Amortization		0		0	0		0	0	0	0	0
Total Depreciation & Amortization Expenses		**32,349,802**		**0**	**32,349,802**		**18,006,810**	**3,507,184**	**21,513,995**	**9,068,731**	**1,312,993**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		12,900,000		0	12,900,000		7,622,631	1,126,786	8,749,417	3,036,308	679,570
Payroll Tax		839,629		0	839,629		558,528	58,361	616,889	140,018	38,480
Taxes on Common Assets		93,000		0	93,000		53,506	8,600	62,106	23,182	4,748
Corporate Capital Tax		3,286,134		0	3,286,134		1,890,606	303,883	2,194,489	819,147	167,759
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		3,192,741		0	3,192,741		1,836,874	295,247	2,132,121	795,867	162,991
Total Taxes		**20,311,504**		**0**	**20,311,504**		**11,962,145**	**1,792,876**	**13,755,021**	**4,814,523**	**1,053,547**
VI. FINANCE EXPENSE		**21,603,263**		**0**	**21,603,263**		**12,504,138**	**1,995,539**	**14,499,677**	**5,333,324**	**1,085,861**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,945,694**	**1,108,466**	**8,054,160**	**2,962,510**	**603,165**
VIII. NET INCOME (LOSS)		**2,894,415**		**0**	**2,894,415**		**1,675,310**	**267,363**	**1,942,673**	**714,561**	**145,484**
COST OF SERVICE SUMMARY											
COST OF GAS		177,264,835		0	177,264,835		27,152,355	5,190,449	32,342,804	24,700,597	6,927,317
OTHER REVENUE		-1,189,728		0	-1,189,728		-959,517	-80,460	-1,039,977	-94,779	-25,680
OPERATING EXPENSES											
Customer Service & Corporate Relations		30,007,662		4,182,701	25,824,961		21,891,142	1,897,702	23,788,844	3,748,597	986,947
Operations & Maintenance		16,165,264		426,161	15,739,104		8,820,273	1,311,054	10,131,328	3,948,407	1,128,335
Organizational Suport		15,707,672		0	15,707,672		10,452,069	1,092,415	11,544,484	2,622,342	720,722
Adjustments to Income		-1,330,599		0	-1,330,599		-885,125	-92,487	-977,612	-221,894	-60,982
Sub-total		60,550,000		4,608,862	55,941,138		40,278,359	4,208,685	44,487,044	10,097,453	2,775,022
DEPRECIATION & AMORTIZATION		32,349,802		0	32,349,802		18,006,810	3,507,184	21,513,995	9,068,731	1,312,993
CAPITAL & OTHER TAXES		20,311,504		0	20,311,504		11,962,145	1,792,876	13,755,021	4,814,523	1,053,547
FINANCE EXPENSE		21,603,263		0	21,603,263		12,504,138	1,995,539	14,499,677	5,333,324	1,085,861
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,945,694	1,108,466	8,054,160	2,962,510	603,165
NET INCOME		2,894,415		0	2,894,415		1,675,310	267,363	1,942,673	714,561	145,484
COST OF SERVICE		325,784,091		4,608,862	321,175,229		117,565,295	17,990,102	135,555,397	57,596,918	13,877,709

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results of Cost of Service Elements
2019/20 Test Year

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Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Ex-Franchise Customers EXF	Fixed Price Offering FPO	Broker BRK	
IV. DEPRECIATION & AMORTIZATION														
Depreciation Expense		17,180,097	1,042	309,305	127,220	55,337	95,727	[redacted]			0	80	0	
Amortization of Cust. Contributions		-1,130,083	-296	-93,380	-291,436	-120,152	-33,676	[redacted]			0	0	0	
Depreciation: Common Assets		4,547,217	321	68,631	58,761	5,936	26,076	[redacted]			0	1,440	0	
Amortization Expense (Deferreds)		1,806,963	106	31,641	13,531	5,620	9,993	[redacted]			0	0	0	1e
Demand Side Management Amortization Expense (Deferred)		9,945,608	0	99,456	0	0	0	[redacted]			0	0	0	
Furnace Replacement Program		0	0	0	0	0		[redacted]			0	0	0	
Ex-Franchise Depreciation & Amortization		0	0	0	0	0		[redacted]			0	0	0	
Total Depreciation & Amortization Expenses		**32,349,802**	**1,172**	**415,653**	**-91,924**	**-53,258**	**98,119**	[redacted]			**0**	**1,520**	**0**	
V. CAPITAL & OTHER TAXES								[redacted]						
Municipal Taxes		12,900,000	753	225,889	96,601	40,124	71,338	[redacted]			0	0	0	
Payroll Tax		839,629	59	12,673	10,850	1,096	4,815	[redacted]			0	266	0	
Taxes on Common Assets		93,000	5	1,238	481	213	567	[redacted]			0	1	0	
Corporate Capital Tax		3,286,134	171	43,747	16,994	7,539	20,017	[redacted]			0	29	0	1e
Business Taxes		0	0	0	0	0		[redacted]			0	0	0	
Other		0	0	0	0	0		[redacted]			0	0	0	
Income Taxes		3,192,741	166	42,504	16,511	7,325	19,448	[redacted]			0	28	0	
Total Taxes		**20,311,504**	**1,154**	**326,051**	**141,437**	**56,298**	**116,185**	[redacted]			**0**	**323**	**0**	
VI. FINANCE EXPENSE		**21,603,263**	**1,117**	**285,091**	**111,721**	**49,562**	**129,948**	[redacted]			**0**	**189**	**0**	1e
VII. CORPORATE ALLOCATION		**12,000,000**	**621**	**158,360**	**62,058**	**27,530**	**72,182**	[redacted]			**0**	**105**	**0**	1e
VIII. NET INCOME (LOSS)		**2,894,415**	**150**	**38,197**	**14,968**	**6,640**	**17,410**	[redacted]			**0**	**25**	**0**	1e
COST OF SERVICE SUMMARY								[redacted]						
COST OF GAS		177,264,835	11,740	224,131	[redacted]		881,122	[redacted]			0	44,879	0	1a,2d
OTHER REVENUE		-1,189,728	-40	-8,380	-7,159	-760	-3,232	[redacted]			0	-175	0	1e
OPERATING EXPENSES								[redacted]						
Customer Service & Corporate Relations		30,007,662	1,679	255,250	225,841	46,932	142,499	[redacted]			0	14,617	0	
Operations & Maintenance		16,165,264	1,599	449,220	370,821	13,339	122,216	[redacted]			0	0	0	
Organizational Suport		15,707,672	1,088	229,498	202,980	20,504	90,132	[redacted]			0	4,973	0	1e
Adjustments to Income		-1,330,599	-94	-20,083	-17,194	-1,737	-7,630	[redacted]			0	-421	0	
Sub-total		60,550,000	4,273	913,884	782,447	79,038	347,217	[redacted]			0	19,168	0	
DEPRECIATION & AMORTIZATION		32,349,802	1,172	415,653	-91,924	-53,258	98,119	[redacted]			0	1,520	0	1e
CAPITAL & OTHER TAXES		20,311,504	1,154	326,051	141,437	56,298	116,185	[redacted]			0	323	0	1e
FINANCE EXPENSE		21,603,263	1,117	285,091	111,721	49,562	129,948	[redacted]			0	189	0	1e
CORPORATE ALLOCATION		12,000,000	621	158,360	62,058	27,530	72,182	[redacted]			0	105	0	1e
NET INCOME		2,894,415	150	38,197	14,968	6,640	17,410	[redacted]			0	25	0	1e
COST OF SERVICE		325,784,091	20,187	2,352,987	[redacted]		1,658,951	[redacted]			0	66,034	0	1e

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Schedule 10.1.6

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Revenue of Non-Gas Costs at Existing Rates
2019/20 Test Year

	Account Description	Total Allocated Dollars	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	FRPGS Fixed Price	
1	DOWNSTREAM REVENUES																
2	FROM CURRENT RATES																
3																	
4	Number of Bills	[redacted]															
5	Basic Monthly Charge				$14.00	$77.00	$1,118.31	$274.06	$2,353.33	$115,409.95	$8,026.07	$1,042.72					
6	Basic Monthly Revenue	58,178,524	[redacted]														
7																	
8	Billing Demand	[redacted]															
9	Monthly Demand Charge				$0.00	$0.00	$149.52	$128.61	$156.26	$0.00	$4.28	$76.80					
10	Monthly Demand Revenue	3,900,839	[redacted]														1d,1e
11																	
12	Billing Volume	[redacted]															
13	Volumetric Charge				$85.22	$34.46	$6.39	$0.00	$0.01	$0.00	$0.09	$2.90					
14	Volumetric Revenue	78,281,763	[redacted]														
15																	
16	Total Downstream Revenue	140,361,127	[redacted]														
17																	
18																	
19																	
20	UPSTREAM REVENUES																
21	FROM CURRENT RATES																
22																	
23																	
24	Billing Demand	[redacted]															
25	Monthly Demand Charge				$0.00	$0.00	$6.18	$9.88	$10.98	$0.00	$0.00	$2.92					
26	Monthly Demand Revenue	104,769	[redacted]														
27																	
28	Billing Volume	[redacted]															
29	Volumetric Charge				$7.11	$7.09	$4.83	$4.53	$4.54	$0.00	$0.00	$4.68	$1.64	$0.78	$1.30	$31.37	1d,1e
30	Volumetric Revenue	12,041,361	[redacted]														
31																	
32	Total Upstream Revenue	12,146,130	[redacted]														
33																	
34																	
35	TOTAL NON-GAS REVENUES	152,524,872	0	0	109,941,344	30,132,872	6,274,676	8,024	1,484,485	1,385,423	236,483	845,414	[redacted]			17,615	1e
36	FROM CURRENT RATES																

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

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Schedule 11.1.0
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BILLED VS. BILLED

	Load	Annual Use		FEB 1/19 APPROVED BILLED RATES				NOV 1/19 PROPOSED BILLED RATES				BILL IMPACTS	
	Factor	10^3m^3	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$220	$388	($16)	-4.0%
		1.98	70	$168	$0	$468	$636	$168	$0	$435	$603	($32)	-5.1%
(Typical Residential Customer)		**2.22**	78	$168	$0	$523	$691	$168	$0	$487	$655	($36)	-5.2%
		2.80	99	$168	$0	$662	$830	$168	$0	$616	$784	($46)	-5.5%
		3.20	113	$168	$0	$755	$923	$168	$0	$703	$871	($52)	-5.7%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$809	$977	($60)	-5.8%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,488	$2,656	($185)	-6.5%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,078	$3,002	$6	0.2%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,911	$11,835	$32	0.3%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$124,700	$125,624	$365	0.3%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,097	$77,965	$78,968	$169,029	$475	0.3%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,097	$48,728	$78,968	$139,793	($9,577)	-6.4%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,097	$81,213	$131,613	$224,923	($15,081)	-6.3%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,097	$162,426	$263,226	$437,749	($28,839)	-6.2%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,097	$355,496	$576,112	$943,704	($61,546)	-6.1%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,097	$722,459	$1,170,807	$1,905,364	($123,711)	-6.1%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,097	$20,947	$63,651	$96,696	($14,278)	-12.9%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,097	$25,988	$78,968	$117,053	($17,396)	-12.9%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,097	$43,314	$131,613	$187,024	($28,111)	-13.1%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,097	$86,627	$263,226	$361,950	($54,899)	-13.2%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,097	$189,598	$576,112	$777,806	($118,584)	-13.2%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,097	$385,311	$1,170,807	$1,568,216	($239,628)	-13.3%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$40,464	$26,285	$78,846	$14,376	22.3%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$171,195	$111,205	$294,497	$65,095	28.4%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$273,912	$177,928	$463,937	$104,946	29.2%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$21,581	$26,285	$59,963	$10,486	21.2%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$91,304	$111,205	$214,606	$48,636	29.3%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$146,087	$177,928	$336,112	$78,611	30.5%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,169	$15,180	$24,100	$42,448	($195)	-0.5%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,169	$21,252	$33,740	$58,160	($225)	-0.4%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,169	$30,359	$48,200	$81,728	($270)	-0.3%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,969	$99,027	$276,715	$388,710	($94,122)	-19.5%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,969	$495,133	$1,383,573	$1,891,676	($409,524)	-17.8%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,969	$990,267	$2,767,147	$3,770,382	($803,777)	-17.6%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,969	$52,814	$276,715	$342,498	($63,929)	-15.7%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,969	$264,071	$1,383,573	$1,660,613	($258,561)	-13.5%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,969	$528,142	$2,767,147	$3,308,258	($501,851)	-13.2%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,969	$764,401	$4,005,001	$4,782,371	($719,517)	-13.1%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$280,078	$9,891	$302,938	$76,013	33.5%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$360,101	$12,717	$385,787	$102,094	36.0%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$880,246	$31,086	$924,301	$271,621	41.6%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$149,375	$9,891	$172,235	$29,960	21.1%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$192,054	$12,717	$217,740	$42,883	24.5%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$469,465	$31,086	$513,520	$126,882	32.8%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,423	$40,473	$79,761	$132,658	($4,935)	-3.6%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,423	$84,320	$265,870	$362,613	($36,083)	-9.1%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,423	$421,599	$1,329,349	$1,763,371	($180,056)	-9.3%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,423	$13,491	$79,761	$105,676	($15,516)	-12.8%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,423	$44,971	$265,870	$323,264	($51,513)	-13.7%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,423	$224,853	$1,329,349	$1,566,625	($257,211)	-14.1%

2d

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

Attachment 2 IGU-Centra II-27 ii)
Schedule 11.1.0
Page 2 of 2

BASE VS. BASE

	Load Factor	Annual Use 10^3m^3	Mcf	FEB 1/19 APPROVED BASE RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$215	$383	($12)	-3.0%
		1.98	70	$168	$0	$450	$618	$168	$0	$426	$594	($24)	-3.8%
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$477	$645	($27)	-4.0%
		2.80	99	$168	$0	$637	$805	$168	$0	$604	$772	($34)	-4.2%
		3.20	113	$168	$0	$727	$895	$168	$0	$689	$857	($38)	-4.3%
		3.68	130	$168	$0	$837	$1,005	$168	$0	$792	$960	($44)	-4.4%
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,438	$2,606	($136)	-5.0%
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,014	$2,938	$40	1.4%
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,571	$11,495	$209	1.9%
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,813	$121,737	$2,393	2.0%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$54,036	$94,077	$160,209	($995)	-0.6%
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$33,773	$94,080	$139,950	($2,074)	-1.5%
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$56,287	$156,795	$225,179	($2,575)	-1.1%
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$112,574	$313,589	$438,260	($3,826)	-0.9%
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$246,386	$686,340	$944,823	($6,803)	-0.7%
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$500,721	$1,394,820	$1,907,638	($12,460)	-0.6%
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,518	$75,830	$102,445	($2,604)	-2.5%
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$18,012	$94,077	$124,186	($2,913)	-2.3%
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$30,020	$156,795	$198,911	($3,973)	-2.0%
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$60,039	$313,589	$385,726	($6,623)	-1.7%
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$131,406	$686,340	$829,843	($12,923)	-1.5%
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$267,051	$1,394,820	$1,673,968	($24,898)	-1.5%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$40,282	$26,520	$78,899	$14,429	22.4%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$170,425	$112,200	$294,722	$65,320	28.5%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$272,679	$179,520	$464,297	$105,305	29.3%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$21,484	$26,520	$60,101	$10,624	21.5%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$90,893	$112,200	$215,190	$49,220	29.7%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$145,429	$179,520	$337,046	$79,546	30.9%
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$15,180	$21,925	$40,273	($208)	-0.5%
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$21,252	$30,695	$55,115	($243)	-0.4%
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$30,359	$43,850	$77,378	($296)	-0.4%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$154,903	$252,968	$420,839	($37,492)	-8.2%
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$774,514	$1,264,838	$2,052,321	($126,375)	-5.8%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,549,028	$2,529,676	$4,091,673	($237,479)	-5.5%
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$82,615	$252,968	$348,551	($33,375)	-8.7%
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$413,074	$1,264,838	$1,690,881	($105,789)	-5.9%
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$826,148	$2,529,676	$3,368,794	($196,308)	-5.5%
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,195,717	$3,661,300	$4,869,986	($277,292)	-5.4%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$279,616	$21,000	$313,585	$86,660	38.2%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$359,507	$27,000	$399,476	$115,783	40.8%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$878,795	$66,000	$957,764	$305,083	46.7%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$149,129	$21,000	$183,098	$40,822	28.7%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$191,737	$27,000	$231,706	$56,849	32.5%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$468,690	$66,000	$547,659	$161,022	41.6%
Special Contract	[redacted]												
Power Stations	[redacted]												
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,800	$87,873	$127,096	($3,700)	-2.8%
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$55,833	$292,910	$361,166	($14,873)	-4.0%
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$279,165	$1,464,549	$1,756,138	($74,007)	-4.0%
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,933	$87,873	$109,230	($5,165)	-4.5%
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,778	$292,910	$335,111	($17,010)	-4.8%
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$148,888	$1,464,549	$1,625,861	($84,692)	-5.0%

2d

REFERENCE:

IGU/CENTRA I-27 Attachment

PREAMBLE TO IR (IF ANY):

IGU requires additional information to understand this response.

QUESTION:

Please provide a version of the attachment that allocates the balances in the Heating Value Deferral Account based on actual revenue from volumetric charges instead of actual volumes (10^3M^3).

RESPONSE:

Please see the attachment to this response that provides the allocation of the Heating Value Deferral Account based on actual revenue from the non-gas component in Distribution (Commodity Volumetric Charge) and Transportation (Commodity Volumetric Charge) rates.

REFERENCE:

IGU/CENTRA I-22 (d)

PREAMBLE TO IR (IF ANY):

IGU requires additional information to understand

QUESTION:

Please provide the equivalent customer breakdown for the last test year.

RESPONSE:

The following is the breakdown of customers for the 2019/20 fiscal year

Rate Class	Number of Customers
System Supply	
SRES-S	[redacted]
SCOM-S	
LGS-S	
HVF-S	
MLF-S	
INT-S	
Total System Supply	
Fixed Rate Offering	
SRES-F	[redacted]
SCOM-F	
LGS-F	
Total Fixed Rate Offering	
WTS	
SRES-W	[redacted]
SCOM-W	
LGS-W	
HVF-W	
Total WTS	
T-Service	
HVF-T	[redacted]
MLF-T	
PSB-T	
PSS-T	
SPEC-T	
Total Transport	
TOTAL	

1d

REFERENCE:

Appendix 7.6

PREAMBLE TO IR (IF ANY):

IGU requires additional information to understand the sales forecast.

QUESTION:

Does Centra's 2018 Natural Gas Volume Forecast include any impacts on the number of customers subscribing to T-service or their purchase volumes as a result of Centra's proposed Balancing Fees. If not, why not? If so, please discuss how these forecasts were prepared.

RESPONSE:

Centra does not forecast industrial customers' potential migration within Centra's service options, rather it captures this migration after the fact. Centra is neither privy to the evolving operational requirements or risk tolerances of industrial customers, nor how they would respond to Centra's balancing fee proposal.

REFERENCE:

CAC/CENTRA I-20a-v Attachment 2

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the cost allocation methodology provided in the requested sensitivity analysis.

QUESTION:

a) Please confirm there is no Attachment 1 within this response. If not confirmed, please provide a copy of the attachment.

b) Please confirm that Centra does not offer DSM programs to T-Service customers. Please confirm there are no direct benefits to T-Service customers as a result of DSM programming undertaken by other customer classes, such as in the electricity side where domestic conservation can serve to increase export revenues.

RESPONSE:

a) Confirmed. Attachment 2 was inadvertently labeled such that reference to this Attachment should have been Attachment 1.

b) Not confirmed. T-Service customers are eligible and have participated in the Corporation's natural gas DSM.

REFERENCE:

CAC/CENTRA I-20a-v Attachment 2

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the cost allocation methodology provided in the requested sensitivity analysis.

QUESTION:

c) Please explain if the approaches CAC has requested in this response would allocate any costs of DSM to T-service customers.

d) Please provide the underlying supporting data for allocators COM-T and COM-TBS including forecast methodologies used for these allocators. Please comment on if these allocators are used elsewhere in Centra's Cost Allocation schedules (including detail on what Schedules and what line items). Please reconcile these allocators to the 2019/20 total volumetric forecast provided in Appendix 7.2 page 3 of 6.

RESPONSE:

c) In response to the CAC/CENTRA I-20a-c, Centra provided the allocation of DSM amortization costs to all customer classes based on the total system volumes as opposed to the current approach of directly assigning the DSM cost based upon each customer classes' participation in the respective DSM programs. In both approaches the DSM cost is functionalized to Transmission, classified as Energy related, then allocated respectively on the total system volumes or on the basis of anticipated participation by customer classes. Allocated DSM amortization cost is recovered by the Volumetric Charge (Distribution to Customer) from all customers in a class, regardless of whether they are Sales Service or T-Service customers.

d) Please refer to the attachment to this response for the underlying data for allocators COM-T and COM-TBS, and a comparison to the 2019/20 volume forecast provided in

Appendix 7.2 (Update) page 3 of 6. Note, the COM-T allocator is taken directly from the volume forecast.

In Centra's Cost Allocation Study, the COM-T and COM-TBS allocators are not used directly. . However, the COM-T and COM-TBS allocators underlie the calculation of the Peak and Average allocators PAVG-T and PAVG-TBS that are used in the cost allocation to allocate demand related costs to customer classes. For more information regarding the calculation of and use of Peak and Average allocators in the Cost of Service Study, please refer to the response to IGU/CENTRA I-13 part b) and d).

Comparison of Schedule 7.2 Volumes to COM-T and COM-TBS Allocators

Volume by Customer Class (10^3m^3) 2019/20 Forecast	**System Total**	**Residential SGS-R**	**Small Commercial SGS-C**	**Large Gen Service LGS**	**High Volume HVF**	**Cooperative CO-OP**	**Main Line ML**	**Special Contracts SC**	**Power Stations GS**	**Interruptible INT**	
System Supply	[redacted]										
Fixed Price Supply											
Western Transportation Service											
Transportation Service											1d
Total Volume by Customer Class per Appendix 7.2 (Update) - Page 3 of 6	[redacted]										
Split out Co-op from LGS											
Adjusted Total Volume by Customer Class											
Cost of Service Study Allocator:	[redacted]										
COM-T											1d
COM-T%											
COM-TBS (Excludes SC & GS)											1d
COM-TBS%											

REFERENCE:

CAC/CENTRA I-20a-v Attachment 2

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the cost allocation methodology provided in the requested sensitivity analysis.

QUESTION:

e) Going forward, what is Centra's understanding of DSM programming, evaluation and spending approvals given the creation of Efficiency Manitoba and how may these changes impact Centra's revenue requirement and cost allocation practises.

RESPONSE:

As outlined under *The Efficiency Manitoba Act*, the responsibility for all electric and natural gas DSM planning, program design and delivery will move from Manitoba Hydro to the newly established Crown Corporation, Efficiency Manitoba. Under the Act, Efficiency Manitoba will submit their efficiency plans to the Public Utilities Board for their review subject to governing regulations which are currently up for public review. The Public Utilities Board will make a report, with recommendations, to the minister as to whether the plan should be approved, approved with suggested amendments, or rejected.

The DSM Plan as approved by the Minister will be incorporated into Manitoba Hydro's overall planning processes. Until Efficiency Manitoba's DSM Plan is finalized and approved, the Corporation cannot anticipate how Centra's revenue requirement or cost allocation practices may or may not be impacted.

REFERENCE:

IGU/Centra I-13a-d Attachment 2, PAVG methodology

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the cost allocation methodology in Centra's cost allocation Tab 10 Schedules and customer impacts.

QUESTION:

a) Please provide the data and assumptions used to forecast the Coincident Peak day contributions by customer class.
b) Please provide the Coincident Peak-day data as provided in this response in a table similar to Appendix 7.2 for each customer class listed in these tables and for actual years 2011/12 to forecast 2019/20 as well as approved for the 2013/14 test year.
c) Please provide an explanation of how actual Coincident Peak-day data is measured for the system and by customer class. Please confirm it represents the one-time daily peak over the course of the calendar year. If the requested confirmation cannot be provided please provide an explanation.

RESPONSE:

a) Centra prepares the forecast of coincident peak day by initially preparing the annual volumetric forecast by rate class as described in Appendix 7.6 (2018 Natural Gas Volume Forecast). The coincident peak day forecast is based on average of three years of metered historical heat value adjusted coincident peak day volume, collected for the entire Centra system. As Top Consumers and Special rate classes have daily metered volume recorded, the remaining volume is attributable to the Small General Service Residential, Small General Service Commercial and Large General Service sectors where daily volume information is not available. The coincident peak day forecast for each of the three remaining sectors is estimated by utilizing the weather coefficients for each sector. Please see the attachment to this response for the historical and forecast coincident peak-day values.

b) Please see the attachment to this response for the historical and forecast coincident peak-day values.

c) Centra's coincident peak-day is defined as the highest total daily volume for the fiscal year, measured at the points where Centra receives the natural gas from the TCPL pipeline. The coincident peak-day contribution for each customer class is recorded for the Top Consumer (HVF, INT, MLF) and Special (PS, SPEC) rate classes. The SGS Residential, SGS Commercial and LGS contributions equal the difference between the system and the customer classes that are recorded.

Coincidence Peak-day by Customer Class

1	Volumes are stated in 10^3m^3	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	
2		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	
3											
4	**System Supply**	[redacted]									
5	SGS Residential										
6	SGS Commercial										
7	Large General Service										
8	High Volume Firm										
9	Mainline Firm										
10	Interruptible Sales										
11											
12	**Fixed Price Supply**										
13	SGS Residential										
14	SGS Commercial										
15	Large General Service										
16											
17	**Western Transportation Service**										1d
18	SGS Residential										
19	SGS Commercial										
20	Large General Service										
21	High Volume Firm										
22	Mainline Firm										
23	Interruptible Sales										
24											
25	**Transportation Service**										
26	Large General Service										
27	High Volume Firm										
28	Mainline Firm										
29	Interruptible Sales										
30	Power Stations										
31	Special Contract										
32											
33	**Total Volumes**										
34											
35	*Note: Actual Fixed Price Supply coincidence peak-day values are included in their resepective System Supply customer class*										
36	*Note: Forecast of coincident peak-day are heat-value adjusted*										

REFERENCE:

PUB/Centra I-137 & IGU/Centra I-9

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the cost allocation methodology in Centra's cost allocation Tab 10 Schedules and customer impacts.

QUESTION:

In a manner similar to PUB/Centra I-137, please provide the functional factor and classification factor used for each line item in Schedules 10.1.4 and 10.1.5.

RESPONSE:

Please refer to Attachment 1 for the functional factors and to Attachment 2 for the classification factors used for each line item in Schedules 10.1.4 and 10.1.5.

Centra Gas Manitoba, Inc.
2019/20 General Rate Application
Functionalization Phase

Account Description	Account Balance	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Functional Factor	Functionalization Phase: Production	Pipeline	Storage	Transmission	Distribution	OnSite
RATE BASE DETAILS											
I. GAS PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Franchises & Consents	22 384		0	22 384	TPIS	0	0	0	4 475	7 694	10 215
Other Intangible Plant	13 614 400		0	13 614 400	TPIS	0	0	0	2 721 534	4 679 669	6 213 198
Sub-total	13 636 784		0	13 636 784		0	0	0	2 726 008	4 687 363	6 223 413
B. PRODUCTION PLANT											
(Reserved)	0		0	0	PRODPT	0	0	0	0	0	0
Sub-total	0		0	0		0	0	0	0	0	0
C. LOCAL STORAGE PLANT											
Land	0		0	0	STOR	0	0	0	0	0	0
Structures & Improvements	0		0	0	TPIS	0	0	0	0	0	0
Sub-total	0		0	0		0	0	0	0	0	0
D. TRANSMISSION PLANT											
Land	1 027 343		0	1 027 343	TRANSPT	0	0	0	1 027 343	0	0
Structures & Improvements	76 420		0	76 420	TRANS	0	0	0	76 420	0	0
Structures & Improvements - M&R	1 363 403		0	1 363 403	TRANS	0	0	0	1 363 403	0	0
Mains	155 008 042		0	155 008 042	TRANS	0	0	0	155 008 042	0	0
Measuring & Reg. Equipment	14 466 096		0	14 466 096	TRANS	0	0	0	14 466 096	0	0
Other Transmission Equipment	0		0	0	TRANSPT	0	0	0	0	0	0
Sub-total	171 941 305		0	171 941 305		0	0	0	171 941 305	0	0
E. DISTRIBUTION PLANT											
Land	1 764 150		0	1 764 150	DISTPT	0	0	0	0	757 894	1 006 256
Computer Equipment - Hardware	1 180 367		0	1 180 367	DISTPT	0	0	0	0	507 096	673 271
Structures & Improvements	1 377 038		0	1 377 038	DIST	0	0	0	0	1 377 038	0
Structures & Improvements: M & R	5 596 871		0	5 596 871	DIST	0	0	0	0	5 596 871	0
Services	284 239 631		0	284 239 631	ONSITE	0	0	0	0	0	284 239 631
Regulators	56 621 401		0	56 621 401	ONSITE	0	0	0	0	0	56 621 401
Regulators & Meters Installations	0		0	0	ONSITE	0	0	0	0	0	0
Mains	231 880 662		0	231 880 662	DIST	0	0	0	0	231 880 662	0
Measuring & Reg. Equipment	52 283 320	DISTM&R	2 113 687	50 169 633	DIST	0	0	0	0	50 169 633	2 113 687
Telemetry Equipment	5 363 336		0	5 363 336	DIST	0	0	0	0	5 363 336	0
Meters	46 179 936		0	46 179 936	ONSITE	0	0	0	0	0	46 179 936
AMR/ERT Modules	1 703 806		0	1 703 806	ONSITE	0	0	0	0	0	1 703 806
Other Distribution Equipment	0		0	0	DISTPT	0	0	0	0	0	0
Sub-total	688 190 519		2 113 687	686 076 832		0	0	0	0	295 652 530	392 537 989
F. GENERAL PLANT											
Land	136 000		0	136 000	OPEXP	2 347	2 410	2 292	12 123	31 752	85 076
Structures & Improvements	8 619 031		0	8 619 031	OPEXP	148 733	152 756	145 263	768 309	2 012 273	5 391 696
Leasehold Improvements	0		0	0	OPEXP	0	0	0	0	0	0
Office Furniture & Equipment	0		0	0	OPEXP	0	0	0	0	0	0
Target Adjustments	0		0	0	TPIS	0	0	0	0	0	0
Computer Equipment: Software	0		0	0	OPEXP	0	0	0	0	0	0
Computer System Development	0		0	0	OPEXP	0	0	0	0	0	0
Transportation Equipment	-655		0	-655	OPEXP	-11	-12	-11	-58	-153	-410
Vehicle Conversion Kits	0		0	0	OPEXP	0	0	0	0	0	0
Heavy Work Equipment	185 134		0	185 134	MAIN/SVC	0	0	0	42 760	63 966	78 409
Tools & Work Equipment	188		0	188	MAIN/SVC	0	0	0	43	65	80
Rental Equipment: Conv. Bur.	0		0	0	OPEXP	0	0	0	0	0	0
Deferred Ineligible Overhead	3 849 973		0	3 849 973	OPEXP	66 436	68 234	64 887	343 190	898 848	2 408 378
Property, Plant & Equipment Gas Inventory	297 209		0	297 209	TPIS	0	0	0	59 412	102 160	135 637
Sub-total	13 086 880		0	13 086 880		217 505	223 389	212 431	1 225 780	3 108 910	8 098 866
Sub-total Plant-in-Service	886 855 489		2 113 687	884 741 802		217 505	223 389	212 431	175 893 093	303 448 802	406 860 269

Centra Gas Manitoba, Inc.
2019/20 General Rate Application
Functionalization Phase

Account Description	Account Balance	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Functional Factor	Functionalization Phase					
						Production	Pipeline	Storage	Transmission	Distribution	OnSite
G. ADDITIONS TO UTILITY PLANT											
Construction Work in Progress	0		0	0	TPIS	0	0	0	0	0	0
Other Additions	0		0	0	TPIS	0	0	0	0	0	0
Sub-total	0		0	0		0	0	0	0	0	0
Total Utility Plant	**886 855 489**		**2 113 687**	**884 741 802**		**217 505**	**223 389**	**212 431**	**175 893 093**	**303 448 802**	**406 860 269**
II. ACCUMULATED DEPRECIATION											
Intangible Plant	-5 220 747		0	-5 220 747	INTDEP	0	0	0	-1 043 633	-1 794 524	-2 382 590
Production Plant	0		0	0	PRODDEP	0	0	0	0	0	0
Local Storage Plant	0		0	0	STORDEP	0	0	0	0	0	0
Transmission Plant	-41 188 559		0	-41 188 559	TRANSDEP	0	0	0	-41 188 559	0	0
Distribution Plant	-228 870 742		0	-228 870 742	DISTDEP	0	0	0	0	-108 155 309	-120 715 433
General Plant	-7 482 792		0	-7 482 792	GENDEP	-125 166	-128 552	-122 246	-699 568	-1 772 707	-4 634 554
Retirement Work in Progress	0		0	0	TPIS	0	0	0	0	0	0
Sub-total	-282 762 840		0	-282 762 840		-125 166	-128 552	-122 246	-42 931 760	-111 722 540	-127 732 577
Plant Held For Future Use	0		0	0	TPIS	0	0	0	0	0	0
Total Accumulated Depreciation	**-282 762 840**		**0**	**-282 762 840**		**-125 166**	**-128 552**	**-122 246**	**-42 931 760**	**-111 722 540**	**-127 732 577**
III. OTHER RATE BASE											
Contributions in Aid of Construction	-61 613 212		0	-61 613 212	CIAC	0	0	0	-47 617 231	-9 555 777	-4 440 204
Cash Working Capital	13 933 390		0	13 933 390	WC	3 055 956	1 255 232	618 294	2 159 917	2 057 121	4 786 871
Security Deposits	-900 000		0	-900 000	ONSITE	0	0	0	0	0	-900 000
Gas in Storage	33 138 755		0	33 138 755	STOR	0	0	33 138 755	0	0	0
Investment in DSM	53 559 521		0	53 559 521	TRANS	0	0	0	53 559 521	0	0
Investment in Regulatory Costs	2 847 151		0	2 847 151	OPEXP	49 131	50 460	47 985	253 798	664 720	1 781 056
Investment in Site Restoration	1 608 420		0	1 608 420	TPIS	0	0	0	321 525	552 861	734 034
Total Other Rate Base	42 574 026		0	42 574 026		3 105 087	1 305 692	33 805 035	8 677 530	-6 281 074	1 961 756
TOTAL RATE BASE	**646 666 675**		**2 113 687**	**644 552 988**		**3 197 426**	**1 400 529**	**33 895 220**	**141 638 863**	**185 445 189**	**281 089 448**

Account Description	Account Balance	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Functional Factor	Production	Pipeline	Storage	Transmission	Distribution	OnSite	
						Functionalization Phase						
COST OF SERVICE DETAILS												
I. COST OF GAS												
A. FIXED COSTS	[redacted]											
TCPL FS Demand - Sask Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
TCPL STS Demand	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
[redacted]	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
TCPL Firm Service - Emerson to Man Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
TCPL FS Demand - Man Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Other Pipeline Fixed Tolls	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Storage Deliverability	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Joliet to Storage Winter	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Crystal Falls from Storage	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
GLGT Storage to Deward	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Seasonal Storage Capacity	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	1a
Seasonal Storage Deliverability	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Annual Storage Capacity	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Annual Storage Deliverability	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Joliet to Storage Summer	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Crystal Falls to Storage	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
GLGT Emerson to Crystal Falls	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Forecast Capacity Management Revenues	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	0	0	
B. VARIABLE TRANSPORTATION	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			
TCPL FS - Sask Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
TCPL FS - Flowing directly to Man Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
TCPL FS - SSDA (Welwyn)	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Firm Service - Emerson to Man Zone	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
GLGT Storage Transportation	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Storage Transportation	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
ANR Storage Withdrawl Chg.	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Storage Gas - Transportation & Delivery Cost	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	1a
Compressor Fuel: TCPL SSDA	[redacted]		[redacted]	[redacted]	PROD	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Compressor Fuel: Primary	[redacted]		[redacted]	[redacted]	PROD	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Compressor Fuel: Emerson	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Compressor Fuel: TCPL SSDA (Welwyn) to MDA	[redacted]		[redacted]	[redacted]	PROD	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Compressor Fuel: Oklahoma	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Compressor Fuel: Storage & Supplemental US Supplies	[redacted]		[redacted]	[redacted]	STOR	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	0	0	
C. COMMODITY COST	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			
Primary Direct to System	[redacted]		[redacted]	[redacted]	UFG-PRI	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Storage Gas: Primary to System	[redacted]		[redacted]	[redacted]	UFG-PRI	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Oklahoma Supply	[redacted]		[redacted]	[redacted]	UFG-SUPP	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Storage Gas: Supplemental Supply	[redacted]		[redacted]	[redacted]	UFG-SUPP	[redacted]	[redacted]	[redacted]	[redacted]	0	0	1a
Emerson Supply	[redacted]		[redacted]	[redacted]	UFG-SUPP	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Delivered Service	[redacted]		[redacted]	[redacted]	UFG-SUPP	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Fixed Price Offering	[redacted]		[redacted]	[redacted]	UFG-PRI	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	0	0	
D. OTHER GAS COSTS	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]			
Minell Charges	[redacted]		[redacted]	[redacted]	TRANS	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Load Balancing Charges	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	1a
Baseload Volume Price Increment Charges	[redacted]		[redacted]	[redacted]	PIPE	[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	0	0	
Total Cost of Gas	**177 264 835**		**0**	**177 264 835**		**112 024 220**	**43 618 659**	**19 945 429**	**1 676 527**	**0**	**0**	
II. OTHER REVENUE												
Rental Income	0		0	0	ONSITE	0	0	0	0	0	0	
Late Payment Charge	-618 595		0	-618 595	ONSITE	0	0	0	0	0	-618 595	
Broker Revenue	-17 774		0	-17 774	ONSITE	0	0	0	0	0	-17 774	
Other	-553 358		0	-553 358	OPEXP	-9 549	-9 807	-9 326	-49 327	-129 192	-346 157	
Total Other Revenue	**-1 189 728**		**0**	**-1 189 728**		**-9 549**	**-9 807**	**-9 326**	**-49 327**	**-129 192**	**-982 527**	

Account Description	Account Balance	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Functional Factor	Functionalization Phase: Production	Pipeline	Storage	Transmission	Distribution	OnSite
III. OPERATING & ADMINISTRATIVE EXPENSES											
A. CUSTOMER SERVICE & CORPORATE RELATIONS											
Back/Middle Office Services	294 425		0	294 425	GASCOST	186 065	72 448	33 128	2 785	0	0
Billing & Collections	7 705 172		0	7 705 172	ONSITE	0	0	0	0	0	7 705 172
Customer & Public Relations	4 008 554		0	4 008 554	ONSITE	0	0	0	0	0	4 008 554
Customer Information Systems (Banner)	533 983		0	533 983	ONSITE	0	0	0	0	0	533 983
Customer Inspections	7 151 177	LLOCATE	2 391 625	4 759 551	ONSITE	0	0	0	552 385	826 327	5 772 464
Customer Safety Services	1 285 355		0	1 285 355	ONSITE	0	0	0	0	0	1 285 355
Dispatch	2 306 190		0	2 306 190	ONSITE	0	0	0	0	0	2 306 190
Energy Supply, Planning & Support	2 869 025	PROCURE	2 869 025	0	PROCGAS	594 424	729 153	729 153	816 296	0	0
Environment	398 798		0	398 798	MAINS	0	0	0	159 780	239 019	0
Meter Reading	2 511 105		0	2 511 105	ONSITE	0	0	0	0	0	2 511 105
Rate and Regulatory Affairs	943 878		0	943 878	OPEXP	16 288	16 728	15 908	84 138	220 366	590 450
Research & Development	0		0	0	DIST	0	0	0	0	0	0
Sub-total	30 007 662		5 260 651	24 747 012		796 776	818 329	778 189	1 615 383	1 285 712	24 713 273
B. OPERATIONS AND MAINTENANCE											
Communication System	135 343		0	135 343	SCADA	0	0	0	13 534	44 663	77 145
Distribution Maintenance	6 758 662	CUSTSERV	785 368	5 973 294	MAIN/SVC	0	0	0	1 379 630	2 416 672	2 962 360
Load Forecast	70 288		0	70 288	ONSITE	0	0	0	0	0	70 288
Metering	573 718		0	573 718	ONSITE	0	0	0	0	0	573 718
Plant Failures & Emergencies	302 792		0	302 792	ONSITE	0	0	0	0	0	302 792
Quality Assessment	434 989		0	434 989	MAIN/SVC	0	0	0	100 468	150 293	184 229
Regulating Station Maintenance	5 376 364		0	5 376 364	DIST	0	0	0	0	5 376 364	0
System Performance & Reliability	2 513 109		0	2 513 109	MAINS	0	0	0	1 006 884	1 506 225	0
IT - Distribution/Metering	0		0	0	OPEXP	0	0	0	0	0	0
Treasury	0		0	0	OPEXP	0	0	0	0	0	0
Sub-total	16 165 264		785 368	15 379 897		0	0	0	2 500 516	9 494 217	4 170 532
C. ORGANIZATIONAL SUPPORT											
Corporate Governance	2 156 541		0	2 156 541	OPEXP	37 214	38 221	36 346	192 236	503 485	1 349 039
Corporate Infrastructure	4 581 302		0	4 581 302	OPEXP	79 057	81 195	77 212	408 382	1 069 590	2 865 866
Corporate Services	1 864 893		0	1 864 893	OPEXP	32 181	33 052	31 431	166 238	435 394	1 166 597
Departmental Support	5 446 970		0	5 446 970	OPEXP	93 995	96 537	91 802	485 548	1 271 696	3 407 391
Operational Management	1 657 966		0	1 657 966	OPEXP	28 610	29 384	27 943	147 793	387 083	1 037 153
Customer Relations	0		0	0	ONSITE	0	0	0	0	0	0
Sub-total	15 707 672		0	15 707 672		271 057	278 389	264 734	1 400 197	3 667 248	9 826 046
D. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.	852 395		0	852 395	OPEXP	14 709	15 107	14 366	75 983	199 007	533 222
Depreciation, Interest, Taxes	-2 182 994		0	-2 182 994	OPEXP	-37 671	-38 689	-36 792	-194 594	-509 660	-1 365 587
Sub-total	-1 330 599		0	-1 330 599		-22 961	-23 582	-22 426	-118 611	-310 653	-832 365
Total Operating & Administrative Expenses	**60 550 000**		**6 046 019**	**54 503 981**		**1 044 872**	**1 073 136**	**1 020 497**	**5 397 486**	**14 136 524**	**37 877 485**
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense	17 180 097		0	17 180 097	DEPEXP	4 366	4 484	4 264	3 238 204	5 104 370	8 824 409
Amortization of Cust. Contributions	-1 130 083		0	-1 130 083	CIAC	0	0	0	-873 375	-175 268	-81 440
Depreciation: Common Assets	4 547 217		0	4 547 217	OPEXP	78 468	80 591	76 638	405 343	1 061 632	2 844 544
Amortization Expense (Deferred)	1 806 963	AMORT-FPO	0	1 806 963	TPIS	0	0	0	361 214	621 106	824 643
Demand Side Management Amortization Expense (Deferred)	9 945 608		0	9 945 608	TRANS	0	0	0	9 945 608	0	0
Furnace Replacement Program	0		0	0	ONSITE	0	0	0	0	0	0
Ex-Franchise Depreciation & Amortization	0		0	0	TRANS	0	0	0	0	0	0
Total Depreciation & Amortization Expenses	**32 349 802**		**0**	**32 349 802**		**82 834**	**85 075**	**80 902**	**13 076 995**	**6 611 841**	**12 412 155**
V. CAPITAL & OTHER TAXES									20.0%	34.4%	45.6%
Municipal Taxes	12 900 000		0	12 900 000	TPIS	0	0	0	2 578 724	4 434 108	5 887 167
Payroll Tax	839 629		0	839 629	OPEXP	14 489	14 881	14 151	74 845	196 027	525 236
Taxes on Common Assets	93 000		0	93 000	RATEBASE	460	201	4 875	20 370	26 670	40 425
Corporate Capital Tax	3 286 134		0	3 286 134	RATEBASE	16 248	7 117	172 244	719 759	942 368	1 428 398
Business Taxes	0		0	0	RATEBASE	0	0	0	0	0	0
Other	0		0	0	RATEBASE	0	0	0	0	0	0
Income Taxes	3 192 741		0	3 192 741	RATEBASE	15 786	6 915	167 348	699 303	915 585	1 387 803
Total Taxes	**20 311 504**		0	**20 311 504**		**46 983**	**29 114**	**358 618**	**4 093 002**	**6 514 758**	**9 269 029**
VI. FINANCE EXPENSE	**21 603 263**		**0**	**21 603 263**	RATEBASE	**106 817**	**46 788**	**1 132 341**	**4 731 745**	**6 195 187**	**9 390 385**
VII. CORPORATE ALLOCATION	**12 000 000**		**0**	**12 000 000**	RATEBASE	**59 334**	**25 989**	**628 983**	**2 628 350**	**3 441 251**	**5 216 093**
VIII. NET INCOME (LOSS)	**2 894 415**		**0**	**2 894 415**	RATEBASE	**14 311**	**6 269**	**151 712**	**633 961**	**830 034**	**1 258 128**

Account Description	Account Balance	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Functional Factor	Functionalization Phase: Production	Pipeline	Storage	Transmission	Distribution	OnSite
COST OF SERVICE SUMMARY											
COST OF GAS	177 264 835					112 024 220	43 618 659	19 945 429	1 676 527	0	0
OTHER REVENUE	-1 189 728					-9 549	-9 807	-9 326	-49 327	-129 192	-982 527
OPERATING EXPENSES											
Customer Service & Corporate Relations	30 007 662					796 776	818 329	778 189	1 615 383	1 285 712	24 713 273
Operations & Maintenance	16 165 264					0	0	0	2 500 516	9 494 217	4 170 532
Organizational Suport	15 707 672					271 057	278 389	264 734	1 400 197	3 667 248	9 826 046
Adjustments to Income	-1 330 599					-22 961	-23 582	-22 426	-118 611	-310 653	-832 365
Sub-total	60 550 000					1 044 872	1 073 136	1 020 497	5 397 486	14 136 524	37 877 485
DEPRECIATION & AMORTIZATION	32 349 802					82 834	85 075	80 902	13 076 995	6 611 841	12 412 155
CAPITAL & OTHER TAXES	20 311 504					46 983	29 114	358 618	4 093 002	6 514 758	9 269 029
FINANCE EXPENSE	21 603 263					106 817	46 788	1 132 341	4 731 745	6 195 187	9 390 385
CORPORATE ALLOCATION	12 000 000					59 334	25 989	628 983	2 628 350	3 441 251	5 216 093
NET INCOME	2 894 415					14 311	6 269	151 712	633 961	830 034	1 258 128
COST OF SERVICE	**325 784 091**					**113 369 822**	**44 875 222**	**23 309 156**	**32 188 738**	**37 600 403**	**74 440 749**

Account Description	Production Dollars	Classification Factor	Energy	Pipeline Dollars	Classification Allocation Factor	Pipeline Demand	Storage Dollars	Classification Allocation Factor	Storage Demand	Storage Energy	Transmission Dollars	Classification Allocation Factor	Transmission Demand	Transmission Energy
RATE BASE DETAILS														
I. GAS PLANT IN SERVICE														
A. INTANGIBLE PLANT														
Franchises & Consents	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	4 475	TRANPT	4 475	0
Other Intangible Plant	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	2 721 534	TRANPT	2 721 534	0
Sub-total	0		0	0		0	0		0	0	2 726 008		2 726 008	0
B. PRODUCTION PLANT														
(Reserved)	0	ENERGY	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Sub-total	0		0	0		0	0		0	0	0		0	0
C. LOCAL STORAGE PLANT														
Land	0	PRODPT	0	0	DEMAND	0	0	DEMAND	0	0	0	TRANPT	0	0
Structures & Improvements	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Sub-total	0		0	0		0	0		0	0	0		0	0
D. TRANSMISSION PLANT														
Land	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	1 027 343	TRANPT	1 027 343	0
Structures & Improvements	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	76 420	DEMAND	76 420	0
Structures & Improvements - M&R	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	1 363 403	DEMAND	1 363 403	0
Mains	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	155 008 042	DEMAND	155 008 042	0
Measuring & Reg. Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	14 466 096	DEMAND	14 466 096	0
Other Transmission Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Sub-total	0		0	0		0	0		0	0	171 941 305		171 941 305	0
E. DISTRIBUTION PLANT														
Land	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Computer Equipment - Hardware	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Structures & Improvements	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Structures & Improvements: M & R	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Services	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Regulators	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Regulators & Meters Installations	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Mains	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Measuring & Reg. Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Telemetry Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Meters	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
AMR/ERT Modules	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Other Distribution Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Sub-total	0		0	0		0	0		0	0	0		0	0
F. GENERAL PLANT														
Land	2 347	PRODO&M	2 347	2 410	PIPEO&M	2 410	2 292	STORO&M	2 071	221	12 123	TRANO&M	12 116	7
Structures & Improvements	148 733	PRODO&M	148 733	152 756	PIPEO&M	152 756	145 263	STORO&M	131 236	14 027	768 309	TRANO&M	767 841	468
Leasehold Improvements	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Office Furniture & Equipment	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Target Adjustments	0	PRODPT	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Computer Equipment: Software	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Computer System Development	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Transportation Equipment	-11	PRODO&M	-11	-12	PIPEO&M	-12	-11	STORO&M	-10	-1	-58	TRANO&M	-58	0
Vehicle Conversion Kits	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Heavy Work Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	42 760	TRANPT	42 760	0
Tools & Work Equipment	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	43	TRANPT	43	0
Rental Equipment: Conv. Bur.	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Deferred Ineligible Overhead	66 436	PRODO&M	66 436	68 234	PIPEO&M	68 234	64 887	STORO&M	58 621	6 266	343 190	TRANO&M	342 981	209
Property, Plant & Equipment Gas Inventory	0	PRODPT	0	0	PIPEO&M	0	0	STORO&M	0	0	59 412	TRANO&M	59 376	36
Sub-total	217 505		217 505	223 389		223 389	212 431		191 918	20 514	1 225 780		1 225 059	720
Sub-total Plant-in-Service	217 505		217 505	223 389		223 389	212 431		191 918	20 514	175 893 093		175 892 373	720

Account Description	Distribution Dollars	Classification Allocation Factor	Distribution Demand	Distribution Customer	OnSite Dollars	Classification Allocation Factor	Customer
RATE BASE DETAILS							
I. GAS PLANT IN SERVICE							
A. INTANGIBLE PLANT							
Franchises & Consents	7 694	DISTPT	5 674	2 020	10 215	ONSITEPT	10 215
Other Intangible Plant	4 679 669	DISTPT	3 450 988	1 228 680	6 213 198	ONSITEPT	6 213 198
Sub-total	4 687 363		3 456 662	1 230 701	6 223 413		6 223 413
B. PRODUCTION PLANT							
(Reserved)	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
C. LOCAL STORAGE PLANT							
Land	0	DISTPT	0	0	0	ONSITEPT	0
Structures & Improvements	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
D. TRANSMISSION PLANT							
Land	0	DISTPT	0	0	0	ONSITEPT	0
Structures & Improvements	0	DISTPT	0	0	0	ONSITEPT	0
Structures & Improvements - M&R	0	DISTPT	0	0	0	ONSITEPT	0
Mains	0	DISTPT	0	0	0	ONSITEPT	0
Measuring & Reg. Equipment	0	DISTPT	0	0	0	ONSITEPT	0
Other Transmission Equipment	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
E. DISTRIBUTION PLANT							
Land	757 894	DISTPT	558 903	198 990	1 006 256	ONSITEPT	1 006 256
Computer Equipment - Hardware	507 096	DISTPT	373 954	133 142	673 271	ONSITEPT	673 271
Structures & Improvements	1 377 038	DEMAND	1 377 038	0	0	CUST	0
Structures & Improvements: M & R	5 596 871	DEMAND	5 596 871	0	0	CUST	0
Services	0	CUST	0	0	284 239 631	CUST	284 239 631
Regulators	0	CUST	0	0	56 621 401	CUST	56 621 401
Regulators & Meters Installations	0	CUST	0	0	0	CUST	0
Mains	231 880 662	MINPLANT	154 587 108	77 293 554	0	CUST	0
Measuring & Reg. Equipment	50 169 633	DEMAND	50 169 633	0	2 113 687	CUST	2 113 687
Telemetry Equipment	5 363 336	DEMAND	5 363 336	0	0	CUST	0
Meters	0	CUST	0	0	46 179 936	CUST	46 179 936
AMR/ERT Modules	0	DISTPT	0	0	1 703 806	CUST	1 703 806
Other Distribution Equipment	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	295 652 530		218 026 844	77 625 686	392 537 989		392 537 989
F. GENERAL PLANT							
Land	31 752	DISTO&M	21 247	10 505	85 076	ONSITEO&M	85 076
Structures & Improvements	2 012 273	DISTO&M	1 346 508	665 765	5 391 696	ONSITEO&M	5 391 696
Leasehold Improvements	0	DISTO&M	0	0	0	ONSITEO&M	0
Office Furniture & Equipment	0	DISTO&M	0	0	0	ONSITEO&M	0
Target Adjustments	0	DISTO&M	0	0	0	ONSITEO&M	0
Computer Equipment: Software	0	DISTO&M	0	0	0	ONSITEO&M	0
Computer System Development	0	DISTO&M	0	0	0	ONSITEO&M	0
Transportation Equipment	-153	DISTO&M	-102	-51	-410	ONSITEO&M	-410
Vehicle Conversion Kits	0	DISTO&M	0	0	0	ONSITEO&M	0
Heavy Work Equipment	63 966	DISTPT	47 171	16 795	78 409	ONSITEPT	78 409
Tools & Work Equipment	65	DISTPT	48	17	80	ONSITEPT	80
Rental Equipment: Conv. Bur.	0	DISTO&M	0	0	0	ONSITEO&M	0
Deferred Ineligible Overhead	898 848	DISTO&M	601 462	297 386	2 408 378	ONSITEO&M	2 408 378
Property, Plant & Equipment Gas Inventory	102 160	DISTO&M	68 360	33 800	135 637	ONSITEO&M	135 637
Sub-total	3 108 910		2 084 693	1 024 216	8 098 866		8 098 866
Sub-total Plant-in-Service	303 448 802		223 568 199	79 880 603	406 860 269		406 860 269

Account Description	Production Dollars	Classification Factor	Energy	Pipeline Dollars	Classification Allocation Factor	Pipeline Demand	Storage Dollars	Classification Allocation Factor	Storage Demand	Storage Energy	Transmission Dollars	Classification Allocation Factor	Transmission Demand	Transmission Energy
G. ADDITIONS TO UTILITY PLANT														
Construction Work in Progress	0	PRODPT	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Other Additions	0	PRODPT	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Sub-total	0		0	0		0	0		0	0	0		0	0
Total Utility Plant	**217 505**		**217 505**	**223 389**		**223 389**	**212 431**		**191 918**	**20 514**	**175 893 093**		**175 892 373**	**720**
II. ACCUMULATED DEPRECIATION														
Intangible Plant	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	-1 043 633	TRANDEP	-1 043 624	-10
Production Plant	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	0	TRANDEP	0	0
Local Storage Plant	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	0	TRANDEP	0	0
Transmission Plant	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	-41 188 559	TRANDEP	-41 188 180	-378
Distribution Plant	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	0	TRANDEP	0	0
General Plant	-125 166	PRODDEP	-125 166	-128 552	PIPEDEP	-128 552	-122 246	STORDEP	-110 441	-11 805	-699 568	TRANDEP	-699 561	-6
Retirement Work in Progress	0	PRODDEP	0	0	PIPEDEP	0	0	STORDEP	0	0	0	TRANDEP	0	0
Sub-total	-125 166		-125 166	-128 552		-128 552	-122 246		-110 441	-11 805	-42 931 760		-42 931 365	-394
Plant Held For Future Use	0	PRODPT	0	0	DEMAND	0	0	STORPT	0	0	0	TRANPT	0	0
Total Accumulated Depreciation	**-125 166**		**-125 166**	**-128 552**		**-128 552**	**-122 246**		**-110 441**	**-11 805**	**-42 931 760**		**-42 931 365**	**-394**
III. OTHER RATE BASE														
Contributions in Aid of Construction	0	PRODPT	0	0	PIPEPT	0	0	STORPT	0	0	-47 617 231	TRANPT	-47 617 231	0
Cash Working Capital	3 055 956	PRODWC	3 055 956	1 255 232	PIPEWC	1 255 232	618 294	STORWC	565 487	52 807	2 159 917	TRANWC	866 716	1 293 201
Security Deposits	0	PRODRTBASE	0	0	PIPERTBASE	0	0	STORRTBASE	0	0	0	TRANRTBASE	0	0
Gas in Storage	0	PRODPT	0	0	ENERGY	0	33 138 755	ENERGY	0	33 138 755	0	TRANRTBASE	0	0
Investment in DSM	0	PRODPT	0	0	PIPEPT	0	0	STORPT	0	0	53 559 521	ENERGY	0	53 559 521
Investment in Regulatory Costs	49 131	PRODO&M	49 131	50 460	PIPEO&M	50 460	47 985	STORO&M	43 352	4 634	253 798	TRANO&M	253 643	155
Investment in Site Restoration	0	PRODPT	0	0	PIPEO&M	0	0	STORO&M	0	0	321 525	TRANO&M	321 329	196
Total Other Rate Base	**3 105 087**		**3 105 087**	1 305 692		**1 305 692**	**33 805 035**		**608 839**	**33 196 196**	**8 677 530**		**-46 175 543**	**54 853 073**
TOTAL RATE BASE	**3 197 426**		**3 197 426**	**1 400 529**		**1 400 529**	**33 895 220**		**690 315**	**33 204 905**	**141 638 863**		**86 785 465**	**54 853 398**

Account Description	Distribution Dollars	Classification Allocation Factor	Distribution Demand	Distribution Customer	OnSite Dollars	Classification Allocation Factor	Customer
G. ADDITIONS TO UTILITY PLANT							
Construction Work in Progress	0	DISTPT	0	0	0	ONSITEPT	0
Other Additions	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
Total Utility Plant	**303 448 802**		**223 568 199**	**79 880 603**	**406 860 269**		**406 860 269**
II. ACCUMULATED DEPRECIATION							
Intangible Plant	-1 794 524	DISTDEP	-1 349 796	-444 728	-2 382 590	ONSITEDEP	-2 382 590
Production Plant	0	DISTDEP	0	0	0	ONSITEDEP	0
Local Storage Plant	0	DISTDEP	0	0	0	ONSITEDEP	0
Transmission Plant	0	DISTDEP	0	0	0	ONSITEDEP	0
Distribution Plant	-108 155 309	DISTDEP	-81 351 730	-26 803 579	-120 715 433	ONSITEDEP	-120 715 433
General Plant	-1 772 707	DISTDEP	-1 333 386	-439 321	-4 634 554	ONSITEDEP	-4 634 554
Retirement Work in Progress	0	DISTDEP	0	0	0	ONSITEDEP	0
Sub-total	-111 722 540		-84 034 912	-27 687 628	-127 732 577		-127 732 577
Plant Held For Future Use	0	DISTPT	0	0	0	ONSITEPT	0
Total Accumulated Depreciation	**-111 722 540**		**-84 034 912**	**-27 687 628**	**-127 732 577**		**-127 732 577**
III. OTHER RATE BASE							
Contributions in Aid of Construction	-9 555 777	DEMAND	-9 555 777	0	-4 440 204	ONSITERTBASE	-4 440 204
Cash Working Capital	2 057 121	DISTWC	1 448 145	608 976	4 786 871	ONSITEWC	4 786 871
Security Deposits	0	DISTRTBASE	0	0	-900 000	CUST	-900 000
Gas in Storage	0	DISTRTBASE	0	0	0	ONSITERTBASE	0
Investment in DSM	0	DISTPT	0	0	0	ONSITERTBASE	0
Investment in Regulatory Costs	664 720	DISTO&M	444 796	219 924	1 781 056	ONSITEO&M	1 781 056
Investment in Site Restoration	552 861	DISTO&M	369 946	182 915	734 034	ONSITEO&M	734 034
Total Other Rate Base	**-6 281 074**		**-7 292 889**	**1 011 815**	**1 961 756**		**1 961 756**
TOTAL RATE BASE	**185 445 189**		**132 240 398**	**53 204 790**	**281 089 448**		**281 089 448**

Account Description	Production Dollars	Classification Factor	Energy	Pipeline Dollars	Classification Allocation Factor	Pipeline Demand	Storage Dollars	Classification Allocation Factor	Storage Demand	Storage Energy	Transmission Dollars	Classification Allocation Factor	Transmission Demand	Transmission Energy	
COST OF SERVICE DETAILS															
I. COST OF GAS															
A. FIXED COSTS															
TCPL FS Demand - Sask Zone	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
TCPL STS Demand	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
TCPL Firm Service - Emerson to Man Zone	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
TCPL FS Demand - Man Zone	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Other Pipeline Fixed Tolls	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Storage Deliverability	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Joliet to Storage Winter	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Crystal Falls from Storage	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
GLGT Storage to Deward	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	1a
Seasonal Storage Capacity	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Seasonal Storage Deliverability	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Annual Storage Capacity	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Annual Storage Deliverability	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Joliet to Storage Summer	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Crystal Falls to Storage	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
GLGT Emerson to Crystal Falls	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Forecast Capacity Management Revenues	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	
B. VARIABLE TRANSPORTATION															
TCPL FS - Sask Zone	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
TCPL FS - Flowing directly to Man Zone	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
TCPL FS - SSDA (Welwyn)	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Firm Service - Emerson to Man Zone	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
GLGT Storage Transportation	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Storage Transportation	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
ANR Storage Withdrawl Chg.	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Storage Gas - Transportation & Delivery Cost	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	1a
Compressor Fuel: TCPL SSDA	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Compressor Fuel: Primary	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Compressor Fuel: Emerson	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Compressor Fuel: TCPL SSDA (Welwyn) to MDA	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Compressor Fuel: Oklahoma	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Compressor Fuel: Storage & Supplemental US Supplies	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	
C. COMMODITY COST															
Primary Direct to System	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Storage Gas: Primary to System	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Oklahoma Supply	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Storage Gas: Supplemental Supply	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	1a
Emerson Supply	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Delivered Service	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Fixed Price Offering	[redacted]	ENERGY	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	
D. OTHER GAS COSTS															
Minell Charges	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	
Load Balancing Charges	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	1a
Baseload Volume Price Increment Charges	[redacted]	ENERGY	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	DEMAND	[redacted]	[redacted]	[redacted]	ENERGY	[redacted]	[redacted]	
Sub-total	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	
Total Cost of Gas	**112 024 220**		**112 024 220**	**43 618 659**		**43 618 659**	**19 945 429**		**18 019 383**	**1 926 046**	**1 676 527**		**198 444**	**1 478 083**	

Account Description	Distribution Dollars	Classification Allocation Factor	Distribution Demand	Distribution Customer	OnSite Dollars	Classification Allocation Factor	Customer
COST OF SERVICE DETAILS							
I. COST OF GAS							
A. FIXED COSTS							
TCPL FS Demand - Sask Zone	0	DISTPT	0	0	0	ONSITEPT	0
TCPL STS Demand	0	DISTPT	0	0	0	ONSITEPT	0
[redacted]	0	DISTPT	0	0	0	ONSITEPT	0
TCPL Firm Service - Emerson to Man Zone	0	DISTPT	0	0	0	ONSITEPT	0
TCPL FS Demand - Man Zone	0	DISTPT	0	0	0	ONSITEPT	0
Other Pipeline Fixed Tolls	0	DISTPT	0	0	0	ONSITEPT	0
ANR Storage Deliverability	0	DISTPT	0	0	0	ONSITEPT	0
ANR Joliet to Storage Winter	0	DISTPT	0	0	0	ONSITEPT	0
ANR Crystal Falls from Storage	0	DISTPT	0	0	0	ONSITEPT	0
GLGT Storage to Deward	0	DISTPT	0	0	0	ONSITEPT	0
Seasonal Storage Capacity	0	DISTPT	0	0	0	ONSITEPT	0
Seasonal Storage Deliverability	0	DISTPT	0	0	0	ONSITEPT	0
Annual Storage Capacity	0	DISTPT	0	0	0	ONSITEPT	0
Annual Storage Deliverability	0	DISTPT	0	0	0	ONSITEPT	0
ANR Joliet to Storage Summer	0	DISTPT	0	0	0	ONSITEPT	0
ANR Crystal Falls to Storage	0	DISTPT	0	0	0	ONSITEPT	0
GLGT Emerson to Crystal Falls	0	DISTPT	0	0	0	ONSITEPT	0
Forecast Capacity Management Revenues	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
B. VARIABLE TRANSPORTATION							
TCPL FS - Sask Zone	0	DISTPT	0	0	0	ONSITEPT	0
TCPL FS - Flowing directly to Man Zone	0	DISTPT	0	0	0	ONSITEPT	0
TCPL FS - SSDA (Welwyn)	0	DISTPT	0	0	0	ONSITEPT	0
Firm Service - Emerson to Man Zone	0	DISTPT	0	0	0	ONSITEPT	0
GLGT Storage Transportation	0	DISTPT	0	0	0	ONSITEPT	0
ANR Storage Transportation	0	DISTPT	0	0	0	ONSITEPT	0
ANR Storage Withdrawl Chg.	0	DISTPT	0	0	0	ONSITEPT	0
Storage Gas - Transportation & Delivery Cost	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: TCPL SSDA	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: Primary	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: Emerson	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: Oklahoma	0	DISTPT	0	0	0	ONSITEPT	0
Compressor Fuel: Storage & Supplemental US Supplies	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
C. COMMODITY COST							
Primary Direct to System	0	DISTPT	0	0	0	ONSITEPT	0
Storage Gas: Primary to System	0	DISTPT	0	0	0	ONSITEPT	0
Oklahoma Supply	0	DISTPT	0	0	0	ONSITEPT	0
Storage Gas: Supplemental Supply	0	DISTPT	0	0	0	ONSITEPT	0
Emerson Supply	0	DISTPT	0	0	0	ONSITEPT	0
Delivered Service	0	DISTPT	0	0	0	ONSITEPT	0
Fixed Price Offering	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
D. OTHER GAS COSTS							
Minell Charges	0	DISTPT	0	0	0	ONSITEPT	0
Load Balancing Charges	0	DISTPT	0	0	0	ONSITEPT	0
Baseload Volume Price Increment Charges	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	0		0	0	0		0
Total Cost of Gas	**0**		**0**	**0**	**0**		**0**

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Account Description	Production Dollars	Classification Factor	Energy	Pipeline Dollars	Classification Allocation Factor	Pipeline Demand	Storage Dollars	Classification Allocation Factor	Storage Demand	Storage Energy	Transmission Dollars	Classification Allocation Factor	Transmission Demand	Transmission Energy
II. OTHER REVENUE														
Rental Income	0	CUST	0	0	CUST	0	0	CUST	0	0	0	CUST	0	0
Late Payment Charge	0	CUST	0	0	CUST	0	0	CUST	0	0	0	CUST	0	0
Broker Revenue	0	PRODREVREQ	0	0	PIPEREVREQ	0	0	STORREVREQ	0	0	0	TRANREVREQ	0	0
Other	-9 549	PRODO&M	-9 549	-9 807	PIPEO&M	-9 807	-9 326	STORO&M	-8 426	-901	-49 327	TRANO&M	-49 297	-30
Total Other Revenue	**-9 549**		**-9 549**	**-9 807**		**-9 807**	**-9 326**		**-8 426**	**-901**	**-49 327**		**-49 297**	**-30**
III. OPERATING & ADMINISTRATIVE EXPENSES														
A. CUSTOMER SERVICE & CORPORATE RELATIONS														
Back/Middle Office Services	186 065	PRODGAS	186 065	72 448	PIPEGAS	72 448	33 128	STORGAS	29 929	3 199	2 785	TRANGAS	330	2 455
Billing & Collections	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Customer & Public Relations	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Customer Information Systems (Banner)	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Customer Inspections	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	552 385	DEMAND	552 385	0
Customer Safety Services	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Dispatch	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Energy Supply, Planning & Support	594 424	PRODGAS	594 424	729 153	PIPEGAS	729 153	729 153	STORGAS	658 742	70 411	816 296	DEMAND	816 296	0
Environment	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	159 780	DEMAND	159 780	0
Meter Reading	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Rate and Regulatory Affairs	16 288	PRODO&M	16 288	16 728	PIPEO&M	16 728	15 908	STORO&M	14 372	1 536	84 138	TRANO&M	84 087	51
Research & Development	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Sub-total	796 776		796 776	818 329		818 329	778 189		703 042	75 146	1 615 383		1 612 877	2 506
B. OPERATIONS AND MAINTENANCE														
Communication System	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	13 534	DEMAND	13 534	0
Distribution Maintenance	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	1 379 630	DEMAND	1 379 630	0
Load Forecast	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Metering	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Plant Failures & Emergencies	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Quality Assessment	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	100 468	DEMAND	100 468	0
Regulating Station Maintenance	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
System Performance & Reliability	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	1 006 884	DEMAND	1 006 884	0
IT - Distribution/Metering	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Treasury	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0
Sub-total	0		0	0		0	0		0	0	2 500 516		2 500 516	0
C. ORGANIZATIONAL SUPPORT														
Corporate Governance	37 214	PRODO&M	37 214	38 221	PIPEO&M	38 221	36 346	STORO&M	32 836	3 510	192 236	TRANO&M	192 119	117
Corporate Infrastructure	79 057	PRODO&M	79 057	81 195	PIPEO&M	81 195	77 212	STORO&M	69 756	7 456	408 382	TRANO&M	408 133	249
Corporate Services	32 181	PRODO&M	32 181	33 052	PIPEO&M	33 052	31 431	STORO&M	28 395	3 035	166 238	TRANO&M	166 137	101
Departmental Support	93 995	PRODO&M	93 995	96 537	PIPEO&M	96 537	91 802	STORO&M	82 937	8 865	485 548	TRANO&M	485 253	296
Operational Management	28 610	PRODO&M	28 610	29 384	PIPEO&M	29 384	27 943	STORO&M	25 245	2 698	147 793	TRANO&M	147 703	90
Customer Relations	0	PRODO&M	0	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0
Sub-total	271 057		271 057	278 389		278 389	264 734		239 170	25 564	1 400 197		1 399 345	853
D. ADJUSTMENTS TO INCOME														
Corporate Alloc. & Adj.	14 709	PRODO&M	14 709	15 107	PIPEO&M	15 107	14 366	STORO&M	12 979	1 387	75 983	TRANO&M	75 937	46
Depreciation, Interest, Taxes	-37 671	PRODO&M	-37 671	-38 689	PIPEO&M	-38 689	-36 792	STORO&M	-33 239	-3 553	-194 594	TRANO&M	-194 476	-118
Sub-total	-22 961		-22 961	-23 582		-23 582	-22 426		-20 260	-2 166	-118 611		-118 539	-72
Total Operating & Administrative Expenses	**1 044 872**		**1 044 872**	**1 073 136**		**1 073 136**	**1 020 497**		**921 952**	**98 545**	**5 397 486**		**5 394 199**	**3 287**

Account Description	Distribution Dollars	Classification Allocation Factor	Distribution Demand	Distribution Customer	OnSite Dollars	Classification Allocation Factor	Customer
II. OTHER REVENUE							
Rental Income	0	DISTO&M	0	0	0	CUST	0
Late Payment Charge	0	DISTO&M	0	0	-618 595	CUST	-618 595
Broker Revenue	0	DISTREVREQ	0	0	-17 774	CUST	-17 774
Other	-129 192	DISTO&M	-86 448	-42 743	-346 157	ONSITEO&M	-346 157
Total Other Revenue	**-129 192**		**-86 448**	**-42 743**	**-982 527**		**-982 527**
III. OPERATING & ADMINISTRATIVE EXPENSES							
A. CUSTOMER SERVICE & CORPORATE RELATIONS							
Back/Middle Office Services	0	DISTO&M	0	0	0	ONSITEO&M	0
Billing & Collections	0	DISTO&M	0	0	7 705 172	CUST	7 705 172
Customer & Public Relations	0	DISTO&M	0	0	4 008 554	CUST	4 008 554
Customer Information Systems (Banner)	0	DISTO&M	0	0	533 983	CUST	533 983
Customer Inspections	826 327	CUST	0	826 327	5 772 464	CUST	5 772 464
Customer Safety Services	0	DISTPT	0	0	1 285 355	CUST	1 285 355
Dispatch	0	DISTPT	0	0	2 306 190	CUST	2 306 190
Energy Supply, Planning & Support	0	DISTO&M	0	0	0	ONSITEO&M	0
Environment	239 019	MINPLANT	159 346	79 673	0	ONSITEO&M	0
Meter Reading	0	DISTPT	0	0	2 511 105	CUST	2 511 105
Rate and Regulatory Affairs	220 366	DISTO&M	147 457	72 909	590 450	ONSITEO&M	590 450
Research & Development	0	DISTPT	0	0	0	ONSITEPT	0
Sub-total	1 285 712		306 803	978 909	24 713 273		24 713 273
B. OPERATIONS AND MAINTENANCE							
Communication System	44 663	DEMAND	44 663	0	77 145	CUST	77 145
Distribution Maintenance	2 416 672	DISTPT	1 782 158	634 515	2 962 360	CUST	2 962 360
Load Forecast	0	DISTPT	0	0	70 288	CUST	70 288
Metering	0	DISTO&M	0	0	573 718	CUST	573 718
Plant Failures & Emergencies	0	DISTPT	0	0	302 792	CUST	302 792
Quality Assessment	150 293	DISTPT	110 832	39 460	184 229	CUST	184 229
Regulating Station Maintenance	5 376 364	DISTPT	3 964 761	1 411 603	0	ONSITEPT	0
System Performance & Reliability	1 506 225	MINPLANT	1 004 150	502 075	0	ONSITEPT	0
IT - Distribution/Metering	0	DISTO&M	0	0	0	ONSITEO&M	0
Treasury	0	DISTO&M	0	0	0	ONSITEO&M	0
Sub-total	9 494 217		6 906 564	2 587 653	4 170 532		4 170 532
C. ORGANIZATIONAL SUPPORT							
Corporate Governance	503 485	DISTO&M	336 906	166 579	1 349 039	ONSITEO&M	1 349 039
Corporate Infrastructure	1 069 590	DISTO&M	715 714	353 876	2 865 866	ONSITEO&M	2 865 866
Corporate Services	435 394	DISTO&M	291 343	144 051	1 166 597	ONSITEO&M	1 166 597
Departmental Support	1 271 696	DISTO&M	850 953	420 743	3 407 391	ONSITEO&M	3 407 391
Operational Management	387 083	DISTO&M	259 016	128 067	1 037 153	ONSITEO&M	1 037 153
Customer Relations	0	DISTPT	0	0	0	CUST	0
Sub-total	3 667 248		2 453 932	1 213 317	9 826 046		9 826 046
D. ADJUSTMENTS TO INCOME							
Corporate Alloc. & Adj.	199 007	DISTO&M	133 165	65 842	533 222	ONSITEO&M	533 222
Depreciation, Interest, Taxes	-509 660	DISTO&M	-341 038	-168 622	-1 365 587	ONSITEO&M	-1 365 587
Sub-total	-310 653		-207 873	-102 780	-832 365		-832 365
Total Operating & Administrative Expenses	**14 136 524**		**9 459 426**	**4 677 098**	**37 877 485**		**37 877 485**

Account Description	Production Dollars	Classification Factor	Energy	Pipeline Dollars	Classification Allocation Factor	Pipeline Demand	Storage Dollars	Classification Allocation Factor	Storage Demand	Storage Energy	Transmission Dollars	Classification Allocation Factor	Transmission Demand	Transmission Energy
IV. DEPRECIATION & AMORTIZATION														
Depreciation Expense	4 366	PRODDEPEXP	4 366	4 484	PIPEDEPEXP	4 484	4 264	STORDEPEXP	3 852	412	3 238 204	TRANDEPEXP	3 238 191	14
Amortization of Cust. Contributions	0	PRODO&M	0	0	PIPEO&M	0	0	STORO&M	0	0	-873 375	TRANO&M	-872 843	-532
Depreciation: Common Assets	78 468	PRODO&M	78 468	80 591	PIPEO&M	80 591	76 638	STORO&M	69 237	7 401	405 343	TRANO&M	405 097	247
Amortization Expense (Deferreds)	0	ENERGY	0	0	PIPEO&M	0	0	DEMAND	0	0	361 214	TRANPT	361 214	0
Demand Side Management Amortization Expense (Deferred)	0	CUST	0	0	CUST	0	0	CUST	0	0	9 945 608	ENERGY	0	9 945 608
Furnace Replacement Program	0		0	0		0	0		0	0	0		0	0
Ex-Franchise Depreciation & Amortization	0	ENERGY	0	0	PIPEDEPEXP	0	0	STORDEPEXP	0	0	0	TRANO&M	0	0
Total Depreciation & Amortization Expenses	**82 834**		**82 834**	**85 075**		**85 075**	**80 902**		**73 090**	**7 812**	**13 076 995**		**3 131 658**	**9 945 336**
V. CAPITAL & OTHER TAXES														
Municipal Taxes	0	PRODPT	0	0	PIPEPT	0	0	STORPT	0	0	2 578 724	TRANPT	2 578 724	0
Payroll Tax	14 489	PRODO&M	14 489	14 881	PIPEO&M	14 881	14 151	STORO&M	12 784	1 366	74 845	TRANO&M	74 800	46
Taxes on Common Assets	460	PRODRTBASE	460	201	PIPERTBASE	201	4 875	STORRTBASE	99	4 775	20 370	TRANRTBASE	12 481	7 889
Corporate Capital Tax	16 248	PRODRTBASE	16 248	7 117	PIPERTBASE	7 117	172 244	STORRTBASE	3 508	168 736	719 759	TRANRTBASE	441 013	278 746
Business Taxes	0	PRODRTBASE	0	0	PIPERTBASE	0	0	STORRTBASE	0	0	0	TRANRTBASE	0	0
Other	0	PRODRTBASE	0	0	PIPERTBASE	0	0	STORRTBASE	0	0	0	TRANRTBASE	0	0
Income Taxes	15 786	PRODRTBASE	15 786	6 915	PIPERTBASE	6 915	167 348	STORRTBASE	3 408	163 940	699 303	TRANRTBASE	428 480	270 824
Total Taxes	**46 983**		**46 983**	**29 114**		**29 114**	**358 618**		**19 800**	338 818	**4 093 002**		**3 535 498**	**557 504**
VI. FINANCE EXPENSE	**106 817**	PRODRTBASE	**106 817**	**46 788**	PIPERTBASE	**46 788**	**1 132 341**	STORRTBASE	**23 061**	**1 109 280**	**4 731 745**	TRANRTBASE	**2 899 251**	**1 832 493**
VII. CORPORATE ALLOCATION	**59 334**	PRODRTBASE	**59 334**	**25 989**	PIPERTBASE	**25 989**	**628 983**	STORRTBASE	**12 810**	**616 173**	**2 628 350**	TRANRTBASE	**1 610 452**	**1 017 898**
VIII. NET INCOME (LOSS)	**14 311**	PRODRTBASE	**14 311**	**6 269**	PIPERTBASE	**6 269**	**151 712**	STORRTBASE	**3 090**	**148 622**	**633 961**	TRANRTBASE	**388 443**	**245 518**
COST OF SERVICE SUMMARY														
COST OF GAS	112 024 220		112 024 220	43 618 659		43 618 659	19 945 429		18 019 383	1 926 046	1 676 527		198 444	1 478 083
OTHER REVENUE	-9 549		-9 549	-9 807		-9 807	-9 326		-8 426	-901	-49 327		-49 297	-30
OPERATING EXPENSES														
Customer Service & Corporate Relations	796 776		796 776	818 329		818 329	778 189		703 042	75 146	1 615 383		1 612 877	2 506
Operations & Maintenance	0		0	0		0	0		0	0	2 500 516		2 500 516	0
Organizational Suport	271 057		271 057	278 389		278 389	264 734		239 170	25 564	1 400 197		1 399 345	853
Adjustments to Income	-22 961		-22 961	-23 582		-23 582	-22 426		-20 260	-2 166	-118 611		-118 539	-72
Sub-total	1 044 872		1 044 872	1 073 136		1 073 136	1 020 497		921 952	98 545	5 397 486		5 394 199	3 287
DEPRECIATION & AMORTIZATION	82 834		82 834	85 075		85 075	80 902		73 090	7 812	13 076 995		3 131 658	9 945 336
CAPITAL & OTHER TAXES	46 983		46 983	29 114		29 114	358 618		19 800	338 818	4 093 002		3 535 498	557 504
FINANCE EXPENSE	106 817		106 817	46 788		46 788	1 132 341		23 061	1 109 280	4 731 745		2 899 251	1 832 493
CORPORATE ALLOCATION	59 334		59 334	25 989		25 989	628 983		12 810	616 173	2 628 350		1 610 452	1 017 898
NET INCOME	14 311		14 311	6 269		6 269	151 712		3 090	148 622	633 961		388 443	245 518
COST OF SERVICE	**113 369 822**		**113 369 822**	**44 875 222**		**44 875 222**	**23 309 156**		**19 064 760**	**4 244 395**	**32 188 738**		**17 108 649**	**15 080 089**

Account Description	Distribution Dollars	Classification Allocation Factor	Distribution Demand	Distribution Customer	OnSite Dollars	Classification Allocation Factor	Customer
IV. DEPRECIATION & AMORTIZATION			76.35%				
Depreciation Expense	5 104 370	DISTDEPEXP	3 897 214	1 207 156	8 824 409	ONSITEDEPEXP	8 824 409
Amortization of Cust. Contributions	-175 268	DISTO&M	-117 280	-57 988	-81 440	CUST	-81 440
Depreciation: Common Assets	1 061 632	DISTO&M	710 389	351 243	2 844 544	ONSITEO&M	2 844 544
Amortization Expense (Deferreds)	621 106	DISTPT	458 030	163 076	824 643	ONSITEPT	824 643
Demand Side Management Amortization Expense (Deferred)	0	CUST	0	0	0	ENERGY	0
Furnace Replacement Program	0		0	0	0	CUST	0
Ex-Franchise Depreciation & Amortization	0	DISTDEPEXP	0	0	0	ONSITEPT	0
Total Depreciation & Amortization Expenses	**6 611 841**		**4 948 354**	**1 663 487**	**12 412 155**		**12 412 155**
V. CAPITAL & OTHER TAXES							
Municipal Taxes	4 434 108	DISTPT	3 269 901	1 164 207	5 887 167	ONSITEPT	5 887 167
Payroll Tax	196 027	DISTO&M	131 171	64 856	525 236	ONSITEO&M	525 236
Taxes on Common Assets	26 670	DISTPT	19 667	7 002	40 425	ONSITERTBASE	40 425
Corporate Capital Tax	942 368	DISTPT	694 942	247 425	1 428 398	ONSITERTBASE	1 428 398
Business Taxes	0	DISTPT	0	0	0	ONSITERTBASE	0
Other	0	DISTPT	0	0	0	ONSITERTBASE	0
Income Taxes	915 585	DISTPT	675 192	240 393	1 387 803	ONSITERTBASE	1 387 803
Total Taxes	**6 514 758**		**4 790 874**	**1 723 884**	**9 269 029**		**9 269 029**
VI. FINANCE EXPENSE	**6 195 187**	**DISTRTBASE**	**4 417 769**	**1 777 418**	**9 390 385**	ONSITERTBASE	**9 390 385**
VII. CORPORATE ALLOCATION	**3 441 251**	**DISTRTBASE**	**2 453 946**	**987 305**	**5 216 093**	ONSITERTBASE	**5 216 093**
VIII. NET INCOME (LOSS)	**830 034**	**DISTRTBASE**	**591 895**	**238 139**	**1 258 128**	ONSITERTBASE	**1 258 128**
COST OF SERVICE SUMMARY							
COST OF GAS	0		0	0	0		0
OTHER REVENUE	-129 192		-86 448	-42 743	-982 527		-982 527
OPERATING EXPENSES							
Customer Service & Corporate Relations	1 285 712		306 803	978 909	24 713 273		24 713 273
Operations & Maintenance	9 494 217		6 906 564	2 587 653	4 170 532		4 170 532
Organizational Suport	3 667 248		2 453 932	1 213 317	9 826 046		9 826 046
Adjustments to Income	-310 653		-207 873	-102 780	-832 365		-832 365
Sub-total	14 136 524		9 459 426	4 677 098	37 877 485		37 877 485
DEPRECIATION & AMORTIZATION	6 611 841		4 948 354	1 663 487	12 412 155		12 412 155
CAPITAL & OTHER TAXES	6 514 758		4 790 874	1 723 884	9 269 029		9 269 029
FINANCE EXPENSE	6 195 187		4 417 769	1 777 418	9 390 385		9 390 385
CORPORATE ALLOCATION	3 441 251		2 453 946	987 305	5 216 093		5 216 093
NET INCOME	830 034		591 895	238 139	1 258 128		1 258 128
COST OF SERVICE	**37 600 403**		**26 575 814**	**11 024 589**	**74 440 749**		**74 440 749**