CENTRA GAS MANITOBA INC.
2013/14 GENERAL RATE APPLICATION

VOLUME II

COST ALLOCATION & RATE DESIGN

INDEX

Schedules

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11.0 Overview of Tab 11

This Tab provides an explanation of the purpose of a Cost Allocation Study, the process used to allocate costs to customers, and the results of the 2013/14 Cost Allocation Study.

The Cost Allocation Study describes how the costs of serving various customer classes are identified so rates can be designed that correspond to the nature of the costs incurred. Centra Gas Manitoba Inc. ("Centra") has not made substantial changes to its Cost Allocation approach since the last General rate Application ("GRA"). Section 11.1 and 11.2 describe the purpose and process of a Cost Allocation Study. Section 11.3 provides a discussion of refinements made and the results of the Study, and Section 11.4 addresses rate design matters.

11.1 Purpose of a Cost Allocation Study

The principal goal of the rate setting process is to establish rates for various customer classes that are fair, equitable, and not unduly discriminatory. Rates may be considered to be fair and equitable when they reflect the costs incurred to provide the service. The concept that rates should not be unduly discriminatory suggests that rates can be different for the various groups of customers provided there is a reasonable and rational basis for the difference. This difference may be the result of the nature of the service being provided or the recognition that different costs may be incurred to provide a service to different groups of customers. A Cost Allocation Study estimates the cost to provide a specific service to a class of customers.

Centra defines "cost" as the embedded or accounting cost incurred in operating the utility. Some costs may be readily identified as the responsibility of a specific customer class or service. The majority of costs dealt with in this Application are shared by various customer classes and services. Accordingly, there is a need to establish some basis to distribute those costs to the appropriate customer classes and services.

The Cost Allocation Study provides information on the total cost to serve specific customers or customer groups and also provides information on the nature of the costs, whether those costs are fixed or variable, and the factors that affect the variability of the costs. This information is beneficial in terms of determining an appropriate rate design. As such, the Cost Allocation Study provides the basic data upon which rates are based.

11.2 Process of a Cost Allocation Study

The cost allocation process is a three step sequential process consisting of functionalizing, classifying, and allocating all costs.

11.2.1 Functionalize Costs

The first step in the process is to "functionalize" the costs into broadly defined groups ("functions") which describe the purpose or function of the costs. In the case of Centra, there are six such functions, namely Production, Pipeline, Storage, Transmission, Distribution, and Onsite. The first three functions break down the expenses into costs that are incurred upstream of (or prior to) Centra's Transmission and Distribution system, and the next three functions breakdown costs that are incurred downstream or within Centra's Transmission and Distribution system. A brief description of each of these functions follows.

<u>Upstream Functions</u>:

Production

Production costs include the commodity costs of gas supply purchased and flowed directly to the market, including Canadian sourced supply purchased at the Alberta border plus fuel costs to transport the gas to the Manitoba receipt points, and gas supply purchased from U.S. sources. Production costs also include the cost of gas withdrawn from storage to supply the Manitoba load.

Pipeline

Pipeline costs include fixed and variable costs of transporting gas on the TransCanada Pipelines Limited ("TCPL") system from Empress, Alberta to Centra's Transmission and Distribution System, i.e. Centra's Manitoba receipt gates.

Storage

Storage costs include fixed and variable costs of storage services, but do not include the cost of the commodity itself withdrawn from storage to supply the Manitoba load. All U.S. pipeline charges, both fixed and variable, including U.S. fuel costs, are included in this function.

<u>Downstream Functions:</u>

Transmission

Transmission costs include the capital and operating costs of Centra's high-pressure Transmission system, plus the cost of Unaccounted for Gas ("UFG") that occurs on Centra's Transmission and Distribution system. All UFG costs are allocated to the Transmission function for cost allocation purposes, in order to ensure that all customer classes are allocated their appropriate share of the UFG costs regardless of whether they are served from Centra's Transmission or Distribution system.

Distribution

Distribution costs include the capital and operating costs of Centra's high, medium, and low-pressure Distribution systems.

Onsite

Onsite costs include capital and operating costs of Centra's investment in service lines, meters, and other equipment installed on customers' premises, plus the costs of customer accounting and customer service.

11.2.2 Classifying Costs

The second step in the process is to "classify" the costs that have been functionalized. The classification process amounts to identifying the basis of the variability of the costs. For a gas utility, the variability of costs is usually classified according to the following three factors:

1. The volume of gas purchased (Commodity Related);
2. The number of customers on the system (Customer Related); or
3. The capacity requirements needed for a specific day or other time period (Capacity Related).

A brief description of each of the classification factors follows.

Commodity Related

These are costs that are directly affected (they either increase or decrease) by the volume of gas purchased.

Customer Related

These are costs that are directly affected by the number of customers attached to the system. Examples of these costs would include meters, service lines, and billing.

Capacity Related (also referred to as Demand Related)

These are costs that are directly affected by the need to meet daily peak requirements or peak requirements of other time periods resulting in contracted daily deliverability commitments on TCPL or other supply options, as well as the capacities of Centra's own Transmission and Distribution system.

11.2.3 Allocate Costs

The third and final step in the cost allocation process is to "allocate" to the various customer classes the costs that have been functionalized and classified. The classification of costs into “Commodity Related”, “Customer Related”, and “Capacity Related” provides broad guidelines as to how these costs should be allocated to the customer classes. Thus, if costs are classified as customer related it would be reasonable to allocate costs to the various customer classes on the basis of some form of customer numbers, such as pure number of customers, weighted customers, or seasonal customers. The same logic is applied to commodity related costs.

To allocate capacity related costs, Centra uses a “Peak and Average” allocator that recognizes the peak day, but also gives weight to the average use of the system so that all customer classes pay some portion of the capacity costs.

11.3 Results of the 2013/14 Cost Allocation Study

This section provides an outline of the results of the 2013/14 Cost Allocation Study. Centra is not proposing any substantial changes in its approach to cost allocation in this Application, but provides discussion on refinements made and the results of the Study. The Cost allocation Study allows Centra to identify the various cost components and how they affect the rates of the various customer classes. It also allows Centra to establish a rate design that corresponds to the nature of the costs incurred. Centra has included several summary schedules from its Study attached to this Tab and discussed below. Base rates and rate impacts that flow from the Cost Allocation Study will be discussed in Tab 12.

11.3.1 Total Functionalization and Classification by Customer Class

The first step in the cost allocation process is to categorize the total cost of service into the six discrete functions including Production, Pipeline, Storage, Transmission, Distribution and Onsite. The next step in the process involves the classification of these functionalized costs into three categories: commodity or energy-related costs, capacity or demand-related costs, and customer-related costs.

Schedule 11.1.3 provides a summary of the functionalization process results and also summarizes the classification of each function into demand, commodity and customer. Centra continues to allocate the amortized amount of Demand Side Management ("DSM") investment on the basis of expected participation in DSM programs. As a result of further expected participation in DSM programs by the larger volume customer classes (High Volume Firm ("HVF"), Interruptible and Mainline), Centra has moved to functionalizing DSM costs to the Transmission Function and Classifying on the basis of volumes rather than number of customers. This change results in a better alignment between costs and their driver and avoids large increases in the Basic Monthly Charge ("BMC") for classes with relatively few customers.

11.3.2 Allocation Results of Rate Base

Rate base is used to allocate certain components of the Revenue Requirement. The allocation of Rate Base is consistent with the allocation from past General Rate Applications ("GRA"). Centra functionalizes, classifies and allocates each of the components of Rate Base to each customer class. While Rate Base does not ultimately form part of the rates to be paid by customers, the results of the allocation of Rate Base are used to drive the allocation of certain cost of service components. For example, finance expense is functionalized, classified and allocated to each customer class consistent with Rate Base. In addition, Corporate Allocation and Net Income have been functionalized, classified and allocated on the basis of Rate Base.

Schedule 11.1.4 provides the summary of the allocation of each component of Rate Base to each customer class.

11.3.3 Allocation Results of Revenue Requirement

Centra has allocated a total Revenue Requirement of $358,667 million to the various rate classes. The following table reconciles the 2013/14 Cost of Service components, included in Schedule 5.1.0 of Tab 5, to the Cost of Service components included in the 2013/14 Cost Allocation Study, as outlined in Schedule 11.1.0 of this Tab.

Cost of Service vs. Cost Allocation Reconciliation
2013/14 Test Year ($000's)
Reconciliation

	2013/14 Test Year Cost of Service	2013/14 Test Year Cost Allocation
Cost of Gas	168,279	204,187
Other Income	(1,866)	(1,866)
Operating & Administrative	68,800	68,800
Depreciation & Amortization	30,091	30,091
Furnace Repalcement Program	0	3,800
Capital & Other Taxes	18,750	18,750
Finance Expense	17,296	17,296
Corporate Allocation	12,000	12,000
Net Income (Loss)	4,821	5,608
Total Cost of Service	318,172	358,667
2013/14 Total Cost of Service (Tab 5)	318,172	
Less 2013/14 Fiscal Year Cost of Gas	(168,279)	
Add 2013/14 Gas Year Cost of Gas	204,187	
Furnace Replacement Program	3,800	
Less 2013/14 Net Income	(4,821)	
Add 2013/14 annualized Net Income	5,608	
2013/14 Cost Allocation (Sch. 11.1.0)	358,667	

Below is an explanation of the differences between the components of Cost of Service as reflected in Tab 5 of this Application and the Cost of Service used in the Allocation

Study:

- The Cost of Gas of $204.2 million included in the Cost Allocation Study reflects the updated strip date of November 1, 2012 as discussed in Tab 10 as compared with that reflected in IFF12 (which is based on a July 2, 2012 strip date). While the cost of Primary Gas has been included in the Study, it is only used to drive allocations and is not used for rate setting purposes. Centra's current Primary Gas rate of $0.0967/m^3 was last approved in Order 10/13. Centra will file revised Primary Gas rates in conjunction with its next quarterly Application for May 1, 2013.
- The costs of the Furnace Replacement Program ("FRP") fund are netted against General Consumers Revenue for financial statement purposes, as reflected in Schedule 5.2.0 of Tab 5. In Centra's Cost Allocation Study, Centra has grouped the FRP with the Depreciation and Amortization amount as reflected in Schedule 11.5.1. This allows for the direct assignment of these costs to the Small General Service ("SGS") class consistent with prior direction of The Public Utilities Board ("PUB").
- Centra is proposing to implement new rates on August 1, 2013 and as such, it is expected that rates will generate a Net Income of $4.8 million for the 2013/14 fiscal year (April 2013 to March 2014). In order to generate a $4.8 million Net Income in 2013/14, Centra has incorporated an annualized amount of $5.6 million into its Cost Allocation Study.

Schedule 11.1.5 provides the summary of the allocation of each component of Cost of Service to the various customer classes.

11.3.4 Summary of Allocated Costs by Customer Class

Schedule 11.1.0 provides a summary of the total Cost of Service for 2013/14 allocated by customer class, detailed by cost of service element (Cost of Gas, Other Income etc.) and classification (Commodity, Customer or Capacity). The following table is a summary of the allocation of the total Cost of Service for 2013/14 of $358,667 million to the various rate classes compared to total Cost of Service embedded in current rates:

Cost of Service Allocation by Class For August 1,2013 to March 31, 2014 ($000's)	Currently Approved*	2013/14 Proposed	Increase/ (Decrease)
SGS	134,802	137,960	3,159
LGS	47,007	48,216	1,209
High Volume Firm	9,339	9,453	114
Co-op	18	18	(0)
Mainline	2,131	2,411	280
Special Contract	1,705	1,498	(207)
Power Stations	739	389	(350)
Interruptible	4,090	3,755	(335)
Primary Gas **	156,791	130,279	(26,512)
Supplemental Firm	33,636	21,586	(12,050)
Supplemental Interruptible	4,180	1,902	(2,278)
Fixed Rate Primary Gas	6,291	1,198	(5,093)
Total Cost of Service	400,730	358,667	(42,064)

*Currently Approved combines the 2010/11 GRA Non-Gas Costs with the 2011/12 Cost of Gas Costs.

** Currently Approved reflects the 2011/12 Cost of Gas Primary Gas Costs and is simply a placeholder for purposes of the table recognizing that Primary Gas rates (and total costs) change quarterly.

The primary driver of the net overall reduction in the Cost of Service as compared to that currently embedded in rates is a decrease in the Cost of Gas. Non-Gas costs have increased overall by approximately 5% compared to non-Gas costs currently embedded in rates and are the primary driver of the increase to the SGS, Large General Service ("LGS"), HVF and Mainline classes.

11.3.5 Unit Cost Component Summary – All Costs

Schedule 11.1.1 provides an overall summary of the cost allocation process which includes both gas and non-gas costs. The upper portion of the Schedule separates the allocated costs by class and in terms of upstream and downstream costs. Upstream costs are those that are incurred upstream of Centra's receipt gates. These costs apply to all Sales Service and Western Transportation Service ("WTS") (excluding Primary Gas) customers but do not apply to the Transportation Service ("T-Service") customers. The T-Service customers independently arrange for transportation of their supply to the Centra receipt gates and therefore are not responsible for the upstream costs incurred by Centra.

Downstream costs are those incurred downstream of the Centra receipt gates and are the responsibility of all of Centra's customers. For each category the costs have been further segregated (allocated) into rate classes (SGS, LGS, HVF, Co-op, Mainline, Interruptible, Special Contract and Power Stations).

Lines 16 to 22 of Schedule 11.1.1 set out the Billing Determinants for each rate class for the forward period April 1, 2013 to March 31, 2014. The Billing Determinants are either demand billing units, (peak use per day in 10^3m^3/day), commodity units or annual consumption (in 10^3m^3), or annual customer numbers. The upstream billing determinants include all customers except T-Service customers. In the case of Primary Gas, both WTS and T-Service customer volumes are excluded. The downstream billing determinants include annual billing demand, volume and customer numbers for all customers in each class regardless of the service provided.

Lines 27 to 33 show the resulting unit charges by rate class to be embedded in the new base rates. Again, the upstream charges for a particular rate class apply to all customers, excluding the T-Service customers in that rate class. The downstream charges for a particular rate class apply to all customers including T-Service customers in that rate class. The charges are either demand charges ($/10^{3}m^3/day), commodity charges ($/10^{3}m^3), or customer charges ($/customer/month). Note that none of the upstream costs are customer related, i.e. costs that vary directly with the number of customers billed, and therefore no upstream costs have been allocated to the customer category.

Line 24 of Schedule 11.1.1 indicates a Percent in Demand Charge. This refers to the approved rate design methodology whereby for certain rate classes, some (or all) demand related costs are not recovered in the demand charge but are instead recovered as part of the commodity charge. For example for the SGS and LGS rate classes, all of the demand related costs are transferred to the commodity category and recovered in their respective commodity charges. For the HVF and Interruptible rate classes, 35% of the demand related costs are transferred to the commodity category and recovered in their respective commodity charges. The remaining 65% of demand costs are recovered in the respective demand charges. Finally for the Co-op, Mainline, and Power Stations 100% of the demand related costs are recovered in the demand charge and no costs are transferred to the commodity category.

11.3.6 Unit Cost Component Summary – Non-Gas Costs vs. Gas Costs

Each of the upstream and downstream costs described in the prior section and identified in Schedule 11.1.1 contain both gas and non-gas costs. Centra has provided Schedule 11.1.2, which breaks out the upstream and downstream costs on the basis of gas versus non-gas costs.

The Table below compares the 2013/14 Proposed Non-Gas Costs allocated by class to the 2010/11 Approved GRA Non-Gas Costs allocated by class:

Comparison of Non-Gas Costs by Customer Class ($000's)	2010/11 Approved	2013/14 Proposed	Increase/ (Decrease)
SGS	106,833	112,280	5,447
LGS	27,135	29,788	2,653
High Volume Firm	4,854	5,304	450
Co-op	8	11	3
Mainline	1,505	1,845	339
Special Contract	1,595	1,405	(190)
Power Stations	582	262	(320)
Interruptible	2,146	2,146	0
Primary Gas	1,710	1,014	(696)
Supplemental Firm	21	168	147
Supplemental Interruptible	40	15	(25)
Fixed Rate Primary Gas	454	243	(211)
Total Non-Gas Cost of Service	146,883	154,479	7,597

Because the non-gas costs represent a smaller component of the overall bill than do gas costs, the bill impact to system supply customers will be diluted as shown in the Bill Impact Schedules in Tab 12. As reflected in the table above, relative to the overall increase in non-gas costs from the 2010/11 approved to the 2013/14 proposed, the SGS class requires an average increase while the LGS, HVF and Mainline classes require an above average increase. This is driven primarily by their expected greater participation in DSM programs and therefore a greater allocation of DSM costs.

The Special Contract class' share of non-gas costs has declined since the last GRA, driven by a reduction in marketing related costs and taxes (which are lower for all customers in the 2013/14 Test Year). Non-gas costs allocated to the Power Stations decline in the 2013/14 Test Year driven by a reduction in forecast demand levels relative to other customer classes. This is driven by a forecasted decline in usage on the peak day and results in a decline in their allocated portion of non-gas costs.

For the purposes of the preparation of the Cost Allocation Study, Primary Gas and Supplemental Gas are treated as discrete customer classes. Centra seeks approval of a new Primary Gas Overhead Rate (non-gas cost component) of $0.92/10^{3}m^3 (Schedule 11.1.2, line 49) as part of this Application. The Overhead Rate currently embedded in the Primary Gas rate is $1.64/10^{3}m^3. Centra's approach to the allocation of the overhead component of the Primary Gas rate has not changed. The reduction in the Primary Gas Overhead Rate is driven by a reduction in the cost of the commodity since Centra's last GRA which in turn results in a lesser allocation of finance expense, net income, etc. to Primary Gas. Consistent with past practice, Centra will embed the new Primary Gas Overhead Rate as part of its August 2013 Quarterly Primary Gas Application.

Centra has also updated its Fixed Rate Primary Gas Service ("FRPGS") Program Cost Rate ("PCR"). The FRPGS program has been incorporated into Centra's Cost Allocation Study and is treated as a separate service class in the same fashion as Primary and Supplemental Gas. The revised PCR is $31.42/10^{3}m^3, which is higher than the $26.2/10^{3}m^3 currently approved by the PUB. The increase results primarily from lower forecasted volumes experienced for this service, which is partially offset by a reduction in program administration costs.

Non-gas costs allocated to the Supplemental Firm class have increased in the 2013/14 Test Year due to the increase in the proportion of Supplemental Gas costs relative to Primary Gas costs for this class. . Non-gas costs allocated to the Supplemental Interruptible class have declined due to a reduction in the proportion of Supplemental Gas costs relative to Primary Gas costs compared to the 2010/11 GRA.

While the cost of Supplemental Gas has decreased compared to the costs embedded in current rates (2011/12 Cost of Gas), the Supplemental Gas unit rates (Schedule 11.1.1, line 28) have increased compared to current approved rates, due to lower expected volumes which more than offset the overall cost reduction.

11.4 Rate Design Matters

Centra is not proposing changes to its rate design for its customer classes in this Application. A description of Centra's rate design by customer class is provided below.

SGS customers and LGS customers pay a two-part rate consisting of a BMC and Volumetric Charges. The BMC is proposed to remain at $14 per month for SGS and $77 per month for LGS. The BMC does not recover all of the customer related costs for the SGS or LGS classes. All customer costs in excess of those collected in the BMC, plus all capacity and commodity related costs are recovered in the Volumetric Charges for the SGS and LGS classes respectively.

The HVF, Co-op, Mainline, Power Stations and Interruptible classes are billed using a three-part rate design. This rate design includes a BMC, Monthly Demand Charge components and Volumetric (commodity) Charge components. The BMC for these classes recovers 100% of the customer related costs determined for each respective class in the Cost Allocation Study. The Monthly Demand Charge for the HVF and Interruptible classes recovers 65% of the capacity or demand-related costs determined in the Cost Allocation Study. The remaining 35% of capacity costs are added to the commodity costs and recovered through the Volumetric Charges. The Co-op, Mainline and Power Stations class include a Monthly Demand Charge that recovers 100% of the capacity or demand-related costs and Volumetric Charges equal to 100% of commodity related costs.

The Special Contract class pays a two-part rate, with 100% of the customer related and capacity related costs recovered through the Basic Monthly Charge. The Volumetric Charge recovers 100% of the commodity-related costs allocated to the class which is predominantly the cost of UFG.

Commodity Rate Design

In Order 65/11, the PUB directed Centra to propose a process to review its rate design and service structure.

The current rate design was developed 14 years ago, in large part to support the implementation of WTS and to facilitate the competitive retail market for natural gas in Manitoba. The unbundling of the billing components into Primary Gas and Supplemental Gas were the main outcomes of that initiative. In addition, the upstream and downstream services were unbundled into Transportation (to Centra) and Distribution (to Customers) respectively.

This rate design is relatively complex and can be relatively difficult for customers to understand in comparison to the rate design employed by Manitoba Hydro and by other Canadian LDCs, and is also complex to administer.

In Order 65/11, the PUB noted that combining the Primary and Supplemental Gas charges, and/or transportation and distribution charges, may help simplify Centra's rate structure. This simplification could be considered as a starting point in assessing the impacts of such a rate design.

Centra recognizes that there are implications involved with any possible re-bundling of rates. These implications and the potential impacts for stakeholders must be considered. For example, such a change would require consideration of the impacts on WTS. In addition, there may be other implications arising from the re-bundling of Supplemental Gas rates for Firm and Interruptible class customers into a single commodity rate.

Centra proposes to engage in a stakeholder consultation on this issue after the conclusion of the current GRA proceedings.