CENTRA GAS MANITOBA INC.
2013/14 GENERAL RATE APPLICATION

VOLUME II

GAS SUPPLY, TRANSPORTATION & STORAGE PORTFOLIO AND RELATED COSTS

INDEX

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AND RELATED COSTS

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10.0 Overview of Tab 10

Centra’s mandate is to acquire, manage and distribute supplies of natural gas to meet the Manitoba market requirement in a safe, cost-effective, reliable and environmentally appropriate manner. The cost of gas is the most significant cost that Centra incurs and is regulated, with the exception of Fixed Rate Primary Gas Service (“FRPGS”), on a pass-through basis. Gas costs are passed on to customers in their rates without any mark-up or profit to Centra. To ensure that only the cost of gas, no more and no less, is passed on to customers, Centra maintains a number of Purchased Gas Variance Accounts (“PGVA”), which record the differences between the cost of gas embedded in sales rates and the actual cost of gas incurred. These differences are periodically either refunded to or collected from customers by way of rate riders that either decrease (refund) or add to (collect) the base sales rates and form part of the billed rates that are charged to customers.

In this Application, Centra is requesting approval of the actual gas costs incurred in the 2010/11 Gas Year (from November 1, 2010 to October 31, 2011) of $251.3 million and the actual gas costs incurred in the 2011/12 Gas Year (from November 1, 2011 to October 31, 2012) of $160.1 million, as shown on Schedules 10.4.0 and 10.8.0, respectively. Centra is also requesting approval of the forecast gas cost for the current

2012/13 Gas Year (from November 1, 2012 to October 31, 2013) of approximately $204.2 million.

In 2012, Centra received approval in Order 112/12 for the fixed costs arising from new natural gas storage and related inter-state pipeline transportation arrangements with ANR Pipeline Company ("ANR") and the Great Lakes Gas Transmission Limited Partnership ("GLGT"), to become effective on April 1, 2013. Consequently, this Tab discusses the operation of two Gas Supply, Transportation & Storage portfolios; the current portfolio which expires March 31, 2013, and the new portfolio which commences April 1, 2013, and reflects the costs associated with those arrangements.

This Tab provides a description of:

1. Centra's Gas Supply, Transportation & Storage portfolio of assets and the operation of the existing and new portfolios;
2. The changes Centra has made to the existing Gas Supply, Transportation & Storage portfolio since the 2011/12 Cost of Gas ("COG") Application;
3. The actual gas costs incurred and the gas cost deferral balances for the two Gas Years from November 1, 2010 to October 31, 2012 that Centra seeks approval of as part of this Application, and;
4. The forecast of gas costs for the 2012/13 Gas Year that Centra seeks approval of as part of this Application.

10.1 Centra's Gas Supply, Transportation & Storage Portfolio

Centra's Gas Supply, Transportation & Storage Portfolio ("Gas Portfolio") that is used to serve natural gas customers in Manitoba consists of natural gas supplies and the associated transportation and storage arrangements. The total realized cost of Centra's current Gas Portfolio was $251.3 million in 2010/11, as shown below and as found in more detail in Schedule 10.4.0:

Supply Costs	$177.3 million
Fixed Transportation & Storage Costs	$48.3 million
TCPL $31.6 million U.S. assets $16.7 million	
Variable Transportation & Storage Costs	$11.7 million
Other Costs/(Revenues)	$14.0 million
TOTAL	$251.3 million

A detailed breakdown of these costs is provided in Section 10.4, which describes 2010/11 Gas Year costs and PGVA balances.

The total realized cost of Centra's current Gas Portfolio in 2011/12 was $160.1 million as shown below and found in more detail in Schedule 10.8.0:

Supply Costs	$107.1 million
Fixed Transportation & Storage Costs	$44.8 million
TCPL $27.8 million U.S. assets $17.0 million	
Variable Transportation & Storage Costs	$14.1 million
Other Costs/(Revenues)	($6.0 million)
TOTAL	$160.1 million

A detailed breakdown of these costs is provided in Section 10.8 which describes 2011/12 Gas Year costs and PGVA balances.

Gas Supplies

The two components of gas supplies in Centra's Gas Portfolio are Primary Gas and Supplemental Gas.

Primary Gas

Primary Gas is natural gas received from Western Canadian sources, whether supplied by Centra, by marketers through Western Transportation Service ("WTS"), or by contractual arrangements referred to as Primary Gas Delivered Service. The costs captured in the Primary Gas PGVA are outlined in Section 10.4.1 and Section 10.8.1.

Primary Gas – Centra Supply

Centra purchases the majority of its Primary Gas at the Alberta border ("Empress") under a two-year gas supply contract with ConocoPhillips Canada Marketing and Trading ULC ("ConocoPhillips") for the period from November 1, 2012 to October 31, 2014. Prior to November 1, 2012, Centra purchased the majority of its Primary Gas under a three-year supply contract with ConocoPhillips. Under both contracts, the two components of Primary Gas supply are Baseload service (100% take or pay) and Swing service. The monthly levels for these services are set thirty-two days prior to the beginning of each month. The sum total of these services was 86,745 GJ/day as of November 1, 2011 and 89,142 GJ/day as of November 1, 2012.

Natural gas purchased as Baseload service is priced relative to an AECO monthly index as published in the Canadian Gas Price Reporter ("CGPR"), plus an AECO to Empress transportation component. Natural gas purchased as Swing service is priced relative to an AECO daily index as published in the CGPR, plus an AECO to Empress transportation component. The Swing service provides for the purchase of natural gas on a day-ahead basis with the option to revise the quantity requested on an intra-day basis, subject to pipeline nomination deadlines. This allows Centra to react to changes in the market requirement, primarily due to differences between actual and forecast weather conditions. Swing service volumes represent gas supplies that are incremental to Baseload purchases, gas supplies provided by marketers through WTS, and Primary Gas Delivered Service.

Primary Gas – Marketer Supply (WTS)

Manitoba natural gas customers may elect to purchase their Primary Gas directly from a marketer, independent of Centra. The service provided by Centra to facilitate the transportation of these gas supplies is known as Western Transportation Service ("WTS"). The customer arranges, through a marketer, a source of natural gas in Western Canada, which Centra receives at Empress. Centra is responsible for transporting, storing and distributing the Primary Gas acquired by the marketer on behalf of the customer. The price of that Primary Gas is negotiated between the marketer and the customer and is not subject to review or approval by The Public Utilities Board ("PUB"). Centra provides an Agency, Billing and Collection ("ABC") Service to bill the Primary Gas costs on behalf of a marketer to its customers.

The following table provides the number of WTS customers and Maximum Daily Quantity ("MDQ") of Primary Gas for WTS supply as of November 1, 2012, November 1, 2011 and November 1, 2010.

	Number of Customers	Maximum Daily Quantity (GJ/day)
November 1, 2012	17,900	20,058
November 1, 2011	19,600	24,455
November 1, 2010	29,300	27,618

Primary Gas – Primary Gas Delivered Service

In addition to purchases under Centra's Primary Gas supply contract and gas supplied by marketers as part of the WTS, Centra also executes contractual arrangements for Primary Gas Delivered Service whereby a counterparty delivers gas directly to the Manitoba market. Primary Gas Delivered Service is used in lieu of TCPL transportation from Empress and purchases under Centra's Primary Gas supply contract.

In the 2011/12 COG Application, Centra referred to its Primary Gas Delivered Service arrangements as "Delivered Service" only. The "Primary Gas Delivered Service" naming convention was implemented to distinguish between delivered services intended to replace Primary Gas from Western Canada and Supplemental Gas Delivered Service.

<u>Supplemental Gas</u>

Supplemental Gas is natural gas sourced on a daily, monthly or seasonal basis to serve the Manitoba market's peak day and seasonal requirements, and includes U.S. supplies, and Supplemental Gas Delivered Service (Supplemental Gas Peaking Delivered Service and Alternate Supply Service for Interruptible customers).

Supplemental Gas – U.S. Supplies

In Centra's current Gas Portfolio, which expires on March 31, 2013, Oklahoma supply can be delivered via ANR's southwest system to the load in winter and to storage in summer. Louisiana supply can be delivered through ANR's southeast system during the summer months for storage refill purposes. Centra may also purchase supplies in the Michigan market and transport the gas to the Manitoba market using winter GLGT capacity from Farwell or Deward to Emerson.

With the new Gas Portfolio, Chicago supply can be delivered on ANR to storage in both summer and winter. Centra may purchase Michigan supply and transport the gas to the Manitoba market using winter GLGT capacity from Farwell or Deward to Emerson; and/or may purchase Michigan supply at ANR storage injection point for transfer into storage. Emerson supply may also be purchased and transported on TCPL capacity from Emerson to the Manitoba Delivery Area ("MDA") or used to maintain storage injections.

Supplemental Gas – Peaking Delivered Services

Peaking Delivered Services, in which supply is delivered directly to Manitoba by a counterparty for a specified term dependent upon forecasted and actual loads, are another source of Supplemental Gas.

Supplemental Gas – Alternate Supply Service

Curtailment and/or the provision of Alternate Supply Service to Interruptible customers may be required to conserve storage inventories or whenever demand may exceed Centra's deliverability. If supply is available for purchase and transport in the market, Interruptible customers are offered Alternate Supply Service at rates that reflect the cost of obtaining this service. Alternate Supply Service is also a form of Supplemental Gas Delivered Service. It is priced separately for Interruptible customers. Prices and quantities are arranged in a very short time horizon, and rarely more than a day in advance.

<u>Gas Supplies Required for Centra's Design Firm Peak Day</u>

Centra's design firm peak day (the forecast volume of natural gas required to serve all Firm Sales customers, including WTS customers, on the coldest winter day experienced) for the 2011/12 Gas Year was 470,100 GJ/day. For the 2012/13 Gas Year, the design firm peak day is forecast to be approximately 466,400 GJ/day. The following table depicts the sources of supply required to meet the Manitoba market's design firm peak day requirement for the 2011/12 and 2012/13 Gas Years. Appendices 10.1 and 10.2 of Tab 10 provide a graphical illustration of same.

Sources of Supply to Meet Design Firm Peak Day Requirement

	2011/12 Gas Year		*2012/13 Gas Year*	
	(GJ/day)	(%)	(GJ/day)	(%)
Centra Supply	**86,745**	**18.5%**	**134,142**	**28.8%**
WTS Supply	**24,455**	**5.2%**	**20,058**	**4.3%**
Total Supply - FT/ STFT	**111,200**	**23.7%**	**154,200**	**33.1%**
Primary Gas Delivered Service	**80,000**	**17.0%**	**25,000**	**5.4%**
Oklahoma Supply	**7,860**	**1.7%**	**7,860**	**1.7%**
Michigan Supply			**21,000**	**4.5%**
Storage Withdrawal	**208,591**	**44.4%**	**208,591**	**44.7%**
Peaking Delivered Services	**62,449**	**13.3%**	**49,709**	**10.6%**
	470,100	**100%**	**466,400**	**100%**

At the beginning of the winter, under the assumption of a normal weather year, natural gas is dispatched daily using Primary Gas, US supplies, Storage, and Peaking Delivered Services to meet both Firm and Interruptible requirement. As the winter progresses, Centra monitors the extent to which the weather has varied from normal and the resulting storage inventory levels. If it is determined that storage withdrawals are greater than planned, Centra would curtail Interruptible customers as required to conserve storage gas for the firm market, such that it would be able to supply the maximum year firm requirement from that point to the end of the winter. Curtailment of Interruptible customers may also be implemented to ensure that the firm load is met during a particular day’s colder than normal weather. In the event that curtailment is required, Centra endeavours to provide Interruptible Class customers with Alternate Supply Service.

Transportation and Storage Arrangements

<u>TransCanada Pipelines ("TCPL") Transportation</u>

Primary Gas supplies purchased or received at Empress, either as Centra supply or WTS supply, are transported from Western Canada to Saskatchewan and Manitoba by way of Firm Transportation ("FT") or Short-Term Firm Transportation ("STFT") on TCPL's Mainline. The majority of Centra's customers receive natural gas service through meter stations on the Mainline in the MDA while a relatively small number of customers in the Parkland area are supplied from a meter station that is located in Saskatchewan and is part of the Southern Saskatchewan Delivery Area ("SSDA") on the Mainline system. Please see Appendix 10.3 of Tab 10 for a map of these sections of the TCPL system.

Centra holds Storage Transportation Service ("STS") on TCPL between the MDA and Emerson, which facilitates the refill of storage in summer months and also provides access to storage inventory in winter months to serve the load. As of November 1, 2012, Centra also holds FT from Emerson to the MDA, which helps offset deliverability forgone by de-contracting FT from Empress to the MDA, thereby contributing to meeting deliverability requirements. It also provides the benefit of supply basin diversification as it allows greater access to U.S. markets.

<u>ANR and GLGT – Transportation and Storage</u>

Centra leases ANR storage capacity in Michigan, which requires related transportation on the ANR and GLGT pipelines. The storage and related transportation assets are used to improve Centra's transportation load factor from Western Canada. Storage allows Centra to reduce the unutilized demand charges associated with the use of transportation capacity at a low sales load factor. This portfolio of U.S. assets also enhances reliability, diversity and security of supply. Centra's forecast transportation load factor from Western Canada for the 2012/13 Gas Year is approximately 96% compared to a forecast sales load factor of approximately 30%.

In previous Applications, Centra referred to the "backhaul" of natural gas from storage to the Manitoba market which referred to the transportation of natural gas by displacement on a pipeline system. However, changes in the industry have resulted in the reversal of physical flows on segments of GLGT and TCPL on occasion, depending on pipeline nominations and operating conditions. Accordingly, Centra will no longer use the term "backhaul" to describe the movement of gas from storage in Michigan to the Manitoba load, rather, Centra has adopted the terminology of "transporting" storage gas to describe the way in which storage gas reaches the Manitoba market.

10.1.1 Operation of Current Gas Portfolio (to March 31, 2013)

Summer Operation (April 1 through October 31)

Please see Appendix 10.4 of Tab 10 for a map that outlines the summer operation of Centra's current Gas Portfolio (to March 31, 2013).

In the summer months under Centra's current portfolio, Centra purchases Western Canadian gas supplies under its Primary Gas supply contract and transports these and marketer supplies on its FT and STFT capacity on TCPL's Mainline to meet the firm Manitoba market requirement. Primary Gas Delivered Service is also used to serve the market.

Any Manitoba load requirement in excess of Centra's deliverability is usually met through the purchase of incremental supplies delivered directly to Manitoba through Supplemental Gas Peaking Delivered Service arrangements. Interruptible customers may also be curtailed whenever forecast demand exceeds Centra's deliverability.

Once the firm Manitoba market requirement has been met, excess transportation capacity can be used to refill storage in Michigan, to serve Interruptible load, or be released to third parties where feasible and economic.

At the conclusion of a winter season, Centra determines the amount of gas required to be purchased, transported and injected to refill its storage capacity. Once the storage refill requirement is known, Centra accomplishes storage refill by transporting gas under its transportation contracts in the following order:

1. TCPL FT from Empress to the MDA (up to 54,000GJ/day to storage of 110,000 GJ/day);
2. TCPL STS from the MDA to Emerson (up to 54,000 GJ/day);
3. GLGT FT from Emerson to the interconnect with ANR at Crystal Falls, Michigan (up to 53,351 GJ/day); and
4. ANR Firm Transportation Service ("FTS") from Crystal Falls to ANR storage facilities in Northern Michigan (up to 52,448 GJ/day).

In addition to the capacities listed above, Centra holds 7,860 GJ/day of annual FTS on ANR's southwest system to transport Oklahoma supplies to storage as required, and 22,380 GJ/day on ANR's southeast system for the summer season to assist in refilling storage with Louisiana supplies as required.

Winter Operation – (November 1 through March 31)

Please see Appendix 10.5 of Tab 10 for a map that depicts the winter operation of Centra's current Gas Portfolio (to March 31, 2013).

During winter months under Centra's current Gas Portfolio, the Manitoba market requirement is met first with a combination of natural gas purchased under Centra's Primary Gas supply contract and Primary Gas received from marketers (for customers under WTS arrangements), which is transported to the load using a combination of TCPL FT and STFT, as well as with Primary Gas Delivered Service arrangements. Centra may also use its annual FTS contract of 7,860 GJ/day on ANR's southwest system to transport Oklahoma supplies to GLGT and/or purchases of Michigan supply for transport on GLGT to satisfy daily market demand.

In addition, Centra holds seasonal storage in Michigan and utilizes ANR, GLGT and TCPL pipelines to supply the Manitoba market with gas from storage during winter months. Centra holds seasonal storage capacity of 15.5 petajoules ("PJ") which provides a maximum winter deliverability of 208,591 GJ/day, net of pipeline compressor fuel. For the 2011/12 Gas Year, storage inventory was comprised of approximately 66% Primary Gas and 34% Supplemental Gas.

To meet the market requirement, storage volumes and/or U.S. supplies are transported back to Manitoba using Centra's transportation contracts in the following order:

1. ANR FTS from the storage facility to the GLGT interconnect at Deward, Michigan (up to 208,591 GJ/day);
2. GLGT FT from Deward to Emerson (up to 237,388 GJ/day); and,
3. TCPL STS from Emerson to the MDA (up to 215,614 GJ/day).

Oklahoma supply, Michigan and/or Emerson supplies, and storage withdrawals are transported to Manitoba using TCPL STS (referenced above) and TCPL FT from Emerson to the MDA (21,000 GJ/day) to satisfy the daily market requirement.

Any Manitoba load requirement in excess of Centra's deliverability is usually met through the purchase of incremental supplies delivered directly to Manitoba through Supplemental Gas Peaking Delivered Service arrangements. Interruptible customers may also be curtailed to conserve storage inventories or whenever forecast demand exceeds Centra's deliverability.

Centra will serve the Manitoba market requirement with this portfolio until March 31, 2013 when these arrangements expire.

10.1.2 Changes to Current Portfolio since 2011/12 Cost of Gas Application

Since the 2011/12 COG Application filed in January 2011, Centra has introduced a number of changes to the operation of the Canadian assets in its current Gas Portfolio.

As discussed in previous applications, Centra is concerned with high tolls on the TCPL Mainline and the Mainline's competitive position as an outlet for gas from the WCSB. Centra has de-contracted the amount of FT held on the Mainline from Empress in an effort to reduce its fixed costs in the current, uncertain toll environment. The table below shows Centra's contracted FT capacity from Empress for the last three Gas Years:

	TCPL FT Capacity from Empress (GJ/day)		
Gas Year	**2010/11**	**2011/12**	**2012/13**
MDA Deliveries	135,000	110,000	90,000
SSDA Deliveries	2,200	1,200	1,200

In keeping with the approach used in the 2010/11 Gas Year, Centra determined that replacing the deliverability associated with Empress supply and FT capacity on TCPL with Primary Gas Delivered Service for the 2011/12 Gas Year was the most economic alternative. This provided Centra with the financial benefit of reducing fixed costs associated with annual FT, and the flexibility of increasing deliverability as required on a monthly basis depending on the Manitoba market requirement.

For the 2012/13 Gas Year, Centra chose to further de-contract FT from Empress on the TCPL Mainline and replace this deliverability with a combination of STFT and Primary Gas Delivered Service. This combination of short-term assets allows Centra to respond to an increased market requirement during cold months (i.e. to “load shape”) without incurring the fixed costs associated with annual FT. Centra contracted for less Primary Gas Delivered Service during the 2012/13 Gas Year compared to previous years as the economic benefit associated with these arrangements has diminished. Primary Gas Delivered Service provides for a degree of supplier diversity in Centra’s supply portfolio and enables Centra to remain active and current in the market for short-term supplies.

In addition to the changes noted above, Centra has also contracted for 21,000 GJ/day of annual TCPL FT from Emerson to the MDA. This firm capacity helps Centra meet its deliverability requirement while reducing transportation levels from Empress, and also provides the benefit of supply basin diversification as it allows greater access to U.S. markets.

Centra purchased the majority of its Primary Gas requirement under a three-year contract that expired on October 31, 2012. Centra issued a Request for Proposal (“RFP”) for Western Canadian gas supply on April 27, 2012 and proposals were received on May 14, 2012. Centra identified a short-list of proposals based on established criteria and pursued negotiations with those proponents. As a result of the negotiations, a two-year supply contract was executed with the successful proponent, ConocoPhillips, effective November 1, 2012. Consistent with past practice followed in 2009/10, the contract and scoring matrix have been filed in confidence with the PUB.

All of the above-noted changes have been incorporated into the operation of Centra's existing Gas Portfolio. The 2012/13 Gas Year comprises the final five months of Centra's existing Gas Portfolio that expires on March 31, 2013 and the first seven months of its new Gas Portfolio, which takes effect on April 1, 2013. The preceding discussion outlines how Centra has operated its existing Gas Portfolio for the 2010/11 and 2011/12 Gas Year, as well as the winter season of the 2012/13 Gas Year. The following sections provide a description of how Centra will operate its new Gas Portfolio.

10.1.3 Operation of New Gas Portfolio (commencing April 1, 2013)

The operation of the new Gas Portfolio is scheduled to commence on April 1, 2013. The total Gas Portfolio cost for Gas Year 2012/13 on a forecast basis is $204.2 million (Schedule 10.12.3 a, line 57), which comprises the operation of Centra's current Gas Portfolio for the winter of 2012/13 and its new Gas Portfolio for the summer of 2013. Specifically, Centra's existing GLGT and ANR contracts expire on March 31, 2013. Following an application (The Transportation & Storage Application) filed with the PUB on March 23, 2012, Centra received approval of the fixed costs associated with new contractual arrangements for natural gas storage and related transportation with ANR and GLGT. The new contracts provide for total annual storage capacity of 15.5 PJ with 215,614 GJ/day (net of pipeline compressor fuel) of storage deliverability and related pipeline capacity on GLGT and ANR. The total annual fixed cost for these arrangements is approximately $14 million USD, which will remain fixed for each year of the seven year term, beginning April 1, 2013.

Under the new arrangements, Centra will hold seasonal storage capacity with ANR in the amount of 8.1 PJ. This storage capacity has the same characteristics as Centra's current ANR seasonal storage service, which limits injections to summer and withdrawals to winter and allows storage gas to be cycled up to 1.0 times annually.

Centra has added 7.4 PJ of annual storage capacity to its new Gas Portfolio, which allows both injections and withdrawals in any season and allows storage gas to be cycled up to 1.42 times annually as per ANR's tariff. Centra can inject up to 42,286 GJ/day into the annual storage, including during the winter months. Winter injections, combined with the ability to cycle storage up to 1.42 times, effectively provides Centra with the ability to cycle an additional 3.1 PJ (7.4 PJ x 42%) of gas through storage annually. Generally, this flexibility may allow Centra to hold less TCPL capacity from Western Canada to Manitoba in winter, as the ability to refill storage in winter reduces the need to manage storage levels with WCSB purchases. Centra has combined the annual storage with firm winter transportation on ANR from the Joliet Hub to storage to access Chicago supply.

The basic premise by which Centra operates its new Gas Portfolio will be similar to the operation of its existing Gas Portfolio, as it will rely on storage and related U.S. transportation assets to serve the load in winter months and refill storage in summer months. However, while certain components of the existing portfolio have been eliminated, such as long haul transport contracts on ANR from Louisiana and Oklahoma, Centra has added new features to its portfolio, such as short haul transportation from the Chicago market to storage and increased storage deliverability. These new features are addressed in the discussion of the summer and winter operation of Centra's new Gas Portfolio in the following sections.

The following chart compares the storage and transportation capacities of the U.S. contracts associated with the existing and the new Gas Portfolios.

ANR/GLGT Capacities - US and Canadian Units

	Current GST&S Portfolio *(up to March 31, 2013)*		New GST&S Portfolio *(begins April 1, 2013)*	
	Dth	GJ	Dth	GJ
1) ANR Storage - Seasonal				
Capacity	14,700,000	15,509,323	7,677,318	8,100,000
Deliverability	200,310	211,338	89,400	94,322
2) ANR Storage - Annual				
Capacity	NA	NA	7,013,846	7,400,000
Deliverability	NA	NA	117,000	123,442
Storage totals - Capacity	14,700,000	15,509,323	14,691,164	15,500,000
- Deliverability	200,310	211,338	206,400	217,764
ANR Transportation				
3) Crystal Falls to storage (summer)	49,711	52,448	50,200	52,964
4) Joliet to storage (summer)	NA	NA	7,000	7,385
5) Storage to GLGT (winter)	197,706	208,591	204,363	215,614
6) Joliet to storage (winter)	NA	NA	40,000	42,202
ANR SW (annual)	7,450	7,860	NA	NA
ANR SE (summer)	21,212	22,380	NA	NA
GLGT Transportation				
7) Emerson to Crystal Falls (summer)	50,567	53,351	50,500	53,280
8) ANR to Emerson (winter)	225,000	237,388	224,363	236,716

Summer Operation (April 1 through October 31)

Please see Appendix 10.6 of Tab 10 for a map that outlines the summer operations under Centra's new Gas Portfolio beginning April 1, 2013.

Centra will continue to purchase Western Canadian gas supplies under its Primary Gas supply contract and transport these and marketer supplies on its FT and STFT capacity on TCPL's Mainline to meet the firm Manitoba market requirement. Primary Gas Delivered Service arrangements may also be used to meet this requirement.

TCPL FT from Emerson to the MDA will also be used to meet the Manitoba market requirement with gas purchased at Emerson.

Any Manitoba load requirement in excess of Centra's deliverability will continue to be met through the purchase of incremental supplies delivered directly to Manitoba through Supplemental Gas Peaking Delivered Service arrangements. Interruptible customers may also be curtailed whenever forecast demand exceeds Centra's ability to provide and deliver supply under its contractual arrangements.

Once the firm Manitoba market requirement has been met, excess transportation capacity can be used to refill storage in Michigan, to serve Interruptible load, or be released to third parties where feasible and economic.

The storage refill will be accomplished utilizing the following transportation contracts in the new Gas Portfolio:

1. TCPL FT from Empress to the MDA (up to 54,000 GJ/day to storage of 90,000 GJ/day);
2. TCPL STS from the MDA to Emerson, Manitoba (up to 54,000 GJ/day);
3. GLGT FT from Emerson to the interconnect with ANR at Crystal Falls, Michigan (up to 53,280 GJ/day); and,
4. ANR FTS from Crystal Falls to the ANR Pipeline storage facilities in Michigan (up to 52,964 GJ/day).

In addition to maintaining GLGT FT summer capacity from Emerson to Crystal Falls and ANR FTS summer capacity from Crystal Falls to Storage for summer storage refill, Centra has added new FTS capacity on ANR from the Joliet Hub to Storage of 7,385 GJ/day to access Chicago supply.

Winter Operations (November 1 through March 31)

Please see Appendix 10.7 of Tab 10 for an illustration of how Centra will operate its new Gas Portfolio during the winter season.

As with the previous Gas Portfolio, the Manitoba market requirement will be met first with natural gas purchased under Centra's Primary Gas supply contract and Primary Gas received from marketers (for customers under WTS arrangements) and transported to the load using a combination of TCPL FT and STFT. Primary Gas Delivered Service arrangements may also be used to serve the market. Centra may also use purchases of Michigan supply for transport on GLGT to satisfy daily market demand.

Over and above these capabilities, Centra will transport gas withdrawn from storage on the ANR, GLGT and TCPL pipelines to supply the Manitoba market during winter months. Centra will hold storage capacity of 15.5 PJ (8.1 PJ of seasonal storage and 7.4 PJ of annual storage), which provides for a maximum winter deliverability of 215,614 GJ/day, net of pipeline compressor fuel.

To meet the market requirement, storage volumes and/or U.S. supplies will be transported back to Manitoba using Centra's transportation contracts in the following order:

1. ANR FTS from the ANR storage facility to the GLGT interconnect at Deward, Michigan (up to 215,614 GJ/day);
2. GLGT FT from Deward to Emerson (up to 236,716 GJ/day); and
3. TCPL STS from Emerson to the MDA (up to 215,614 GJ/day).

Also included in Centra's new Gas Portfolio for use during the winter months is 42,202 GJ/day of ANR FTS capacity from the Joliet Hub to ANR storage, which will enable Centra to manage its storage levels with access to Chicago supply.

Michigan and/or Emerson supplies and storage withdrawals are transported to Manitoba using TCPL STS (referenced above) and TCPL FT from Emerson to the MDA (21,000 GJ/day) to satisfy daily market demand.

Any Manitoba load requirement in excess of Centra's deliverability is usually met through the purchase of incremental supplies delivered directly to Manitoba through

Supplemental Gas Peaking Delivered Service arrangements. Interruptible customers may also be curtailed to conserve storage or whenever forecast demand exceeds Centra's deliverability.

10.2 Capacity Management Program

The objective of Centra's Capacity Management Program is to optimize the use of its Gas Portfolio to minimize the costs related to the portfolio, while first and foremost ensuring Centra's ability to meet the Manitoba market requirement. Centra enters into transactions with a number of counterparties to meet this objective. Please see Appendix 10.8 of Tab 10 for a description of the types of Capacity Management ("CM") transactions that Centra utilizes.

The need to use an asset in serving the Manitoba market requirement is the first determinant in assessing the potential for CM revenues. If an asset is deemed to be excess for a day/month/season, Centra assesses factors such as changing prices and basis differentials in the various markets and potential counterparty interest in the transaction to determine the value associated with any particular arrangement. The market value of capacity is dependent on the market value for natural gas delivered to a particular market area and, as such, is subject to day-to-day and intra-day fluctuations.

In order to generate CM revenues there must be an alternate market for that service willing to pay a price that covers any incremental costs involved in the transaction and also provide some recovery of the underlying cost of the asset.

Due to fluctuations in weather, pricing and basis differentials, it is difficult to forecast the revenue that may be earned through CM transactions. The five-year rolling average of actual CM revenue serves as a benchmark to estimate the CM credit to be embedded prospectively in customers' transportation rates each year in advance of the realization of these revenues.

As outlined in Section 10.6, CM revenue for the 2010/11 Gas Year was $5.3 million (excluding carrying costs). This amount was $1.6 million less than the forecast amount of $6.9 million that was calculated using the five-year rolling average of actual results for the period from November 1, 2005 through October 31, 2010. During the 2010/11 Gas Year, capacity release transactions accounted for 87% of CM revenue, with the remaining 13% earned by virtue of exchanges. Of the $4.6 million earned through capacity releases, almost three quarters of that was attributable to the sale of transportation by virtue of credits earned using the FT-Risk Alleviation Mechanism ("FT-RAM") on the TCPL Mainline (embedded in the "diversions" reporting category). The remaining one quarter was earned by releasing capacity on the ANR and GLGT pipelines. The variance between actual and forecast for 2010/11 is due primarily to Centra having less TCPL capacity available for release compared to prior years, combined with low basis differentials between Manitoba and Eastern markets during the winter exchange season.

As outlined in section 10.9, during the 2011/12 Gas Year Centra earned $6.4 million (excluding carrying costs) in CM revenue relative to the forecast amount of $6.4 million that was determined by the five-year rolling average of actual results for the period from

November 1, 2006 through October 31, 2011. For the 2011/12 Gas Year, almost all CM revenue was attributable to capacity release transactions, while revenue associated with exchanges totalled only $0.2 million. Again, approximately three-quarters of the CM revenue associated with capacity releases was earned through the sale of transportation by virtue of credits earned using the FT-RAM on the TCPL Mainline, with the remainder attributable to revenue from releases of capacity on the ANR and GLGT pipelines.

The amount embedded in the forecast for the 2012/13 Gas Year is the most recent five-year rolling average of actual CM revenue of $6.3 million (Schedule 10.12.3 b, line 56), which is based on actual results for the period from November 1, 2007 through October 31, 2012.

In Order 112/12, issued on August 23, 2012 in respect of Centra's Transportation & Storage Portfolio Application, the PUB directed Centra to provide the monthly totals of its CM revenue broken down by type of transaction and reflected as a percentage of the costs associated with the operation of each component of Centra's existing and new Gas Portfolio. In response to this directive, Centra has provided a more fulsome description above of CM revenue earned in the 2010/11 and 2011/12 Gas Years. Centra is currently extracting information from its electronic gas management system and actively working to organize the data to develop the necessary reporting that would provide the monthly breakdown of CM revenue attributable to each component of the Gas Portfolio. Centra will file this information with the PUB once it is compiled.

10.3 TCPL and Related Matters

The TCPL Mainline physically transports all natural gas supplies that are consumed in Centra's service territory. Centra's gas supply, planning, and operations are significantly influenced and affected by the current and future business environment experienced by the Mainline.

Over the past decade, the Mainline has experienced dramatic business challenges. A persistent trend of shipper de-contracting on the Mainline has resulted in the current situation where flows on the pipeline are consistently less than half of its capacity. This situation has been exacerbated by the emergence of unconventional shale gas resources in basins closer to major consuming regions.

Since 2006, the level of contracting for long-haul FT has declined on the Mainline by approximately 70%. The level of the benchmark final Eastern Zone Toll ("EZT") in 2006 was $0.94/GJ. By comparison, the National Energy Board ("NEB") approved an interim 2011 EZT effective March 1, 2011 of $2.24/GJ, which continues to be in effect. These toll levels are reflected in the gas cost forecast in this Application.

TransCanada filed its Business and Services Restructuring and Mainline 2012-2013 Tolls Application (the "Restructuring Proposal") with the NEB on September 1, 2011. The oral hearing commenced on June 4, 2012 and concluded on December 5, 2012. A multitude of stakeholders participated in the process with varying degrees of intervention.

Centra registered as an intervener in this matter and participated in the associated regulatory process, including the filing of evidence, cross-examination, and the filing of written final argument.

Centra will continue to adapt to changes in the natural gas marketplace and the overall business environment within which it is operating, recognizing that it has certain limitations given the extent to which it is reliant on the Mainline. Although the NEB proceeding on the matter of TransCanada's Restructuring Application is expected to establish tolls for 2012 and 2013, in all likelihood, considerable toll uncertainty will continue to exist post-2013.

10.4 Description of 2010/11 Gas Year Costs and PGVAs

In this Application Centra is requesting approval of gas cost deferral accounts to October 31, 2012, as Centra's gas cost deferral accounts are managed over Centra's Gas Year from November 1 through October 31. Centra also requests approval for non-Primary Gas rates effective August 1, 2013 for the forecast period of November 1, 2012 to October 31, 2013.

Centra is seeking final approval of the 2010/11 & 2011/12 Gas Year costs, which are summarized in Schedule 10.4.0 and 10.8.0. As shown on line 62 of Schedule 10.4.0, total gas costs for the 2010/11 Gas Year are $251.3 million. As shown on line 63 of Schedule 10.8.0, total gas costs for the 2011/12 Gas Year are $160.1 million.

Centra is requesting that rate riders to dispose of the accumulated balances in its non-Primary Gas cost deferral accounts to October 31, 2012 be implemented on August 1, 2013, coincident with its routine Primary Gas rate change to occur effective that date. As such, the accumulated gas cost deferral balances have been carried forward, including carrying costs, to July 31, 2013, resulting in a forecast balance of $0.01 million owing to Centra. These balances are summarized in Schedule 10.11.0.

Schedules 10.4.1 through 10.7.2 provide the details of all gas cost deferral balances for the period from November 1, 2010 through October 31, 2011 and Schedules 10.8.1 through 10.10.1 summarize the period of November 1, 2011 through October 31, 2012. Schedule 10.11.0 provides a summary to July 31, 2013 of gas cost deferral balances for the 2010/11 and 2011/12 Gas Years, as well as the residual balance of 2009/10 and earlier prior period gas deferrals. All schedules include a forecast of the carrying costs from November 1, 2012 to July 31, 2013. Section 10.12 provides a discussion and estimate of gas costs for the forecast period of November 1, 2012 to October 31, 2013.

On November 1, 2010 new non-Primary Gas Purchased Gas Variance Accounts ("PGVA") and other gas cost deferral accounts were created to accumulate gas cost deferral inflows and outflows during Centra's 2010/11 Gas Year from November 1, 2010 to October 31, 2011.

The following sections are organized in terms of the accumulations in each PGVA and non-Primary Gas cost deferral account for the period from November 1, 2010 to October

31, 2011. These balances are then carried forward to July 31, 2013 to include carrying costs for the period of November 1, 2011 to July 31, 2013.

The Primary Gas, Supplemental Gas, and Distribution PGVA balances for the months of November 2010 through May 2011 have incorporated an actual Unaccounted for Gas ("UFG") percentage of 1.01% of total receipts into the Centra system, based upon the 12-month UFG true-up that was conducted in the summer of 2011.

10.4.1 2010/11 Gas Year Primary Gas PGVA

The Primary Gas PGVA captures the cost of Primary Gas purchases from Western Canada flowing directly to the load on TCPL Mainline FT capacity held by Centra, Primary Gas Delivered Service, Primary Gas withdrawn from storage to meet the Manitoba market requirement, compressor fuel on the TCPL system to transport Primary Gas purchases from Alberta to Manitoba, load balancing agreement fees on the TCPL system and hedging impacts. Primary Gas supplies used to support the UFG requirement are removed from this account and transferred to the Distribution PGVA.

Details pertaining to the Primary Gas PGVA for the period from November 1, 2010 to October 31, 2011 have been provided for information purposes only. While Centra is requesting final approval of actual Primary Gas costs for the 2010/11 Gas Year, it is not seeking any change to Primary Gas rates in this Application as Primary Gas rates are adjusted each quarter through Primary Gas rate applications using the RSM approved by the PUB.

Schedule 10.4.1 sets out the 2010/11 Gas Year's monthly detail for the account. The total October 31, 2011 balance, including carrying costs, is $2.2 million owing to customers as shown on line 25 of Schedule 10.4.1. The cost inflows and outflows are based on actual results to October 31, 2011.

This account operates on a continuum, with the resulting balance at the end of each gas quarter being amortized through a revised Primary Gas rate rider as part of the quarterly Primary Gas RSM. As a result, there are no approved annual Primary Gas PGVA cost inflows and Weighted Average Cost of Gas ("WACOG") outflows against which to compare actual results. Therefore, no variance analysis of the Primary Gas PGVA is provided.

10.4.2 2010/11 Gas Year Supplemental Gas PGVA

The Supplemental Gas PGVA captures the cost of U.S. purchases, Supplemental Gas Delivered Service, and Supplemental Gas withdrawn from storage to meet the load requirement. Since 2011, Centra has been placing greater reliance on Delivered Services to mitigate exposure to the escalating tolls on the TransCanada Mainline. These increased amounts of Delivered Service supplies, in lieu of holding equivalent amounts of FT capacity on the TransCanada Mainline, were originally classified as Supplemental Gas and were considered as such in the forecast. However, this classification resulted in negative impacts on marketers and the potential for wider variations to Firm customers' billing percentages and as a result, it was determined that these specific Delivered Service volumes would be more appropriately re-categorized as Primary Gas supplies from April 1, 2011 forward. The Primary Gas supply category identified on Schedule 10.4.1 line 3, Primary Gas Delivered Service, represents the re-categorized supplies for the post-March 31, 2011 period that were originally categorized as Supplemental Gas Peaking Delivered Service on Schedule 10.4.2(a) line 5.

Schedule 10.4.2(a) sets out the monthly detail for the account. The cost inflows and outflows are based on actual results from November 1, 2010 to October 31, 2011. The total October 31, 2011 balance is $9.6 million owing to customers (line 24). After the inclusion of carrying costs for the period from November 2011 to July 2013, the 2010/11 Gas Year Supplemental Gas PGVA balance on July 31, 2013 is $9.9 million owing to customers (line 53). Centra requests the implementation of rate riders to refund this amount to customers commencing August 1, 2013.

Schedule 10.4.2(b) shows a comparison of actual and approved Supplemental Gas PGVA inflows and outflows, which helps to identify the major contributors to the residual balance. Supplemental cost inflows, net of UFG costs transferred to the Distribution PGVA, were $0.5 million greater than approved costs (line 13).

Line 2 of Schedule 10.4.2(b) provides a comparison of actual and approved Oklahoma supply gas costs. Inflows were $0.2 million less than forecast due to both lower index prices and lower than budgeted volumetric purchases for the applicable period. Forecasted prices were set using a November 1, 2010 forward strip and actual average index prices for supplies came in slightly lower than forecast resulting in a variance of $0.1. The remaining $0.1 million of the total variance is attributable to purchases that were 36,000 GJs less than forecast.

As shown on line 3 of Schedule 10.4.2(b), Supplemental Gas storage utilization was $3.9 million greater than forecast. Actual weather during the January through March 2011 period was 7% colder than normal, creating the requirement to withdraw additional Supplemental Gas supplies from storage.

Line 4 of Schedule 10.4.2(b) displays the Supplemental storage gas portion of exchanges with counterparties for CM transactions, which are priced on the same basis as regular Supplemental Gas storage withdrawals, totalling $2.2 million. These additional storage withdrawals were also driven by the colder than normal weather. CM revenues are discussed in Section 10.2.

Line 5 of Schedule 10.4.2(b) shows a $5.9 million negative variance related to Supplemental Gas Peaking Delivered Service. 9.9 million GJs of Supplemental Gas Peaking Delivered Service purchases were forecast for the 2010/11 Gas Year. By comparison, actual purchases totalled 8.2 million GJs. The lower Supplemental Gas Peaking Delivered Service purchase volumes reduced Supplemental inflows by $6.2 million. This was offset by a $0.3 million positive variance due to slightly higher than forecast average commodity costs for these supplies.

Lines 6 of Schedule 10.4.2(b) displays the $0.6 million of purchases for Alternate Supply Service acquired for Interruptible customers in lieu of curtailment in the months of April and May 2011. For forecasting purposes, Interruptible consumption over and above pre-contracted supplies is considered to be curtailed and therefore, Alternate Supply Service is not included in the forecast. In the 2010/11 Gas Year 147,431 GJ's of Alternate Supply Service purchases were required.

Line 12 of Schedule 10.4.2(b) presents the transfer of Supplemental Gas cost inflows pertaining to the UFG True-up. As noted above, the actual UFG percentage of 1.01% for the months of June 2010 through May 2011 was greater than the 0.90% forecast, resulting in a reallocation of $0.06 million to the Distribution PGVA.

Total Supplemental Gas PGVA Inflows, as indicated on Schedule 10.4.2(b) line 13, were $0.5 million greater than forecast.

Schedule 10.4.2 (b), line 16, compares actual versus forecast Supplemental Gas PGVA WACOG outflows. WACOG outflows were $9.4 million greater than forecast, which was mainly the result of an over-recovery of costs during the period of November 2010 through April 2011 as reduced Supplemental Gas base rates flowing from Centra's 2011/12 Cost of Gas Application were not implemented until May 1, 2011.

Line 17 of Schedule 10.4.2 (b) identifies the corresponding WACOG outflow related to Alternate Supply Service volumes delivered to Interruptible customers in lieu of curtailment in April and May 2011. Costs incurred relating to Alternate Supply Service are fully recovered from customers electing to take the service and therefore, line 17 and line 6 of Schedule 10.4.2(b) correspond directly to one another. As Alternate Supply Service is not forecast, WACOG outflows are $0.6 million greater than forecast as a result.

Total Supplemental Gas PGVA outflows, as indicated on Schedule 10.4.2(b) line 18, were $9.9 million greater than forecast.

The Supplemental Gas PGVA balance at October 31, 2011, as indicated on line 24 of Schedule 10.4.2(a), is $9.6 million owing to customers including carrying costs. After the inclusion of carrying costs for the months of November 2011 through July 2013, the July 31, 2013 closing balance in the Supplemental Gas PGVA is a credit balance of $9.9 million owing to customers (Schedule 10.4.2 (a) line 53).

10.4.3 2010/11 Gas Year Transportation PGVA

This account includes the costs associated with the transportation of supplies on various Canadian and US pipeline systems and the costs for leasing US storage capacity. While most of these costs are fixed charges independent of the volume transported, it also includes certain variable transport costs and other costs such as TCPL Balancing Fees and imputed transportation costs associated with Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Services.

Schedule 10.4.3(a) sets out the monthly detail for the account. The total October 31, 2011 balance is $7.5 million owing to Centra as shown on line 22. The 2010/11 Gas Year Transportation PGVA cost inflows and outflows are based on actual results for the period from November 1, 2010 to October 31, 2011.

As Centra is seeking new Transportation rates effective August 1, 2013, Schedule 10.4.3(a) carries forward the balance of this account to July 31, 2013. After the inclusion of carrying costs for the months from November 2011 to July 2013, the balance in this account is $7.7 million owing to Centra, as shown on line 48.

Schedule 10.4.3(b) shows a comparison of actual and approved annual Transportation PGVA cost inflows and outflows.

Total fixed transportation cost inflows (Line 2 of Schedule 10.4.3(b)) were $2.9 million less than forecast. $2.4 million of this variance is a result of reduced contracting of firm transportation capacity on the TransCanada Mainline. In months where Centra was able to utilize Primary Gas Delivered Service (see Schedule 10.4.1 line 3) and achieve a lower overall net landed cost of gas compared to incurring fixed contract demand charges with TransCanada, Centra reduced its fixed pipeline demand charges by $2.4 million as compared to budget. Favourable U.S. exchange rate variances for the period of April through October 2011 further reduced fixed transportation costs by an additional $0.5 million relative to forecast. For the aforementioned period the exchange rate was forecast at $1.02 CDN/USD in comparison to the actual average exchange rate of $0.98 CDN/USD. In accordance with PUB Order 66/11, Centra revised its forecast, incorporating actual exchange rates for the period from November 2010 through March 2011.

Line 3 of Schedule 10.4.3(b) indicates that variable transportation cost inflows were $0.2 million less than approved. The main contributor to this variance was reduced TCPL variable charges as a result of replacing Firm Mainline transportation with Primary Gas Delivered Service.

Lines 4 and 5 of Schedule 10.4.3(b) denote the variances associated with imputed transportation costs on both Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Services. These matters were discussed previously in Sections 10.4.1 and 10.4.2. In the past, Centra did not estimate the respective costs of commodity and transportation embedded in the landed cost of its Delivered Service supplies due to the limited proportion of the overall annual requirement they represented. As Centra increasingly endeavours to mitigate its exposure to increasing tolls on the TCPL Mainline, Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Services have become a larger percentage of Centra's overall annual requirement. Therefore, in order to more precisely recognize the respective commodity and transportation costs associated with these supplies, Centra has used the best information available to differentiate and allocate these estimated cost components through the appropriate PGVAs.

Supplemental Gas Peaking Delivered Service Imputed Transportation Costs (line 4 of Schedule 10.4.3 (a) were calculated as the remaining amount after deducting estimated embedded commodity costs based on the AECO Monthly 7A Index Price and the Monthly AECO to Empress Transportation Basis Differential from the fully loaded unit cost of Supplemental Gas Peaking Delivered Service supplies.

Primary Gas Delivered Service Imputed Transportation Costs (line 5 of Schedule 10.4.3 (a) were determined to be the remaining amount after the deduction of estimated embedded commodity and upstream compressor fuel costs based on the AECO Monthly 7A Index Price, as well as the monthly AECO to Empress Transportation Basis

Differential. The estimation of commodity costs embedded in these supplies incorporates the additional upstream compressor fuel component in order to maintain consistency with the principles underlying the design of the Quarterly Variable Primary Gas Rate. This rate reflects the costs of Primary Gas delivered at the Empress receipt point, plus TCPL Mainline compressor fuel to deliver these supplies to Centra's distribution system in Manitoba, which are reflected in the rates charged to customers for all Primary Gas products in Manitoba, whether from Centra or natural gas marketers.

Supplemental Gas Peaking Delivered Service Imputed Transportation Costs were $0.8 million greater than budget as shown on line 4 of Schedule 10.4.3 (b). $1.5 million of this variance is the result of imputed unit transportation costs on these supplies that were greater than budgeted. Rather than being a function of high transportation costs embedded in the overall cost of these supplies, this variance is more a function of the large negative values at which the AECO to Empress Transportation Basis Differential settled throughout the year (as great as negative $0.28/GJ). A negative AECO to Empress Transportation Basis Differential has the effect of reducing the net commodity cost component of Supplemental Gas Peaking Delivered Service supplies allocated to the Supplemental Gas PGVA. Correspondingly, this has the offsetting effect of increasing the remaining imputed transportation cost component of these supplies allocated to the Transportation PGVA, all other things being equal. The resulting unit costs for imputed transportation on Supplemental Gas Peaking Delivered Service supplies averaged $0.59/GJ versus the budgeted amount of $0.41/GJ. The offsetting credit amount of $0.7 million for this cost inflow variance pertains to lower than forecast volumes as Supplemental Gas Peaking Delivered Service purchases totalled 8.2 million GJs for the 2010/11 Gas Year relative to the budget of 9.9 million GJs.

Primary Gas Delivered Service Imputed Transportation Costs were $2.4 million greater than budget (line 5 of Schedule 10.4.3 (b)). The variance is the result of 3.5 million GJs of purchases that were not forecast, but were subsequently incurred as Centra continued to actively manage its portfolio in order to further mitigate its exposure to increasing tolls on the TCPL Mainline.

Storage Gas Transportation and Delivery Costs were $0.5 million greater than approved, as shown on Schedule 10.4.3(b), line 6. Actual weather in the January through March 2011 period was colder than normal, thus creating the requirement to withdraw greater than approved budget volumes from storage to meet the winter load.

The TCPL Load Balancing Charges for the 2010/11 Gas Year were $0.02 million less than the 2010/11 approved forecast, as shown at line 7 of Schedule 10.4.3(b),.

Line 8 of Schedule 10.4.3(b) shows miscellaneous charges of $0.05 million that were incurred resulting mainly from a U.S. Customs Merchandise Processing fee paid in December 2010.

Line 9 of Schedule 10.4.3(b) indicates that actual 2010/11 Gas Year CM revenues were less than forecast by $1.6 million. CM revenues are discussed in detail in Section 10.6 below.

In summary, actual inflows to the account were $2.1 million greater than approved forecast amounts as shown on Schedule 10.4.3(b), line 11.

Line 14 of Schedule 10.4.3(b) indicates that WACOG outflows from the Transportation PGVA were $5.5 million less than forecast, with $5.9 million of the differential attributable to Transportation base rates approved for implementation on May 1 2010, which remained in effect through April 30, 2011 that were insufficient to recover the increasing tolls on the TransCanada Mainline. On May 1, 2011 Transportation base rates were revised upwards in PUB Order 66/11 to more accurately reflect market circumstances. The offsetting residual $0.4 million Transportation PGVA WACOG outflow variance results from higher than forecast throughput volumes due to colder than normal weather in the 2010/11 winter period.

The net accumulation in the Transportation PGVA in the 2010/11 Gas Year is a residual balance of $7.5 million owing to Centra as of October 31, 2011. This result is displayed on Schedule 10.4.3(a), line 22. The addition of carrying costs for the months from November 2011 through July 2013 results in a 2010/11 Gas Year Transportation PGVA balance of $7.7 million that is recoverable from customers as of July 31, 2013. This balance is shown on Schedule 10.4.3(a), at line 48.

10.4.4 2010/11 Gas Year Distribution PGVA

The Distribution PGVA captures the cost of UFG on Centra's distribution system. UFG volume losses are allocated between Primary Gas and Supplemental Gas and are accounted for monthly on the basis of the monthly average purchase cost of Primary

Gas supply and Supplemental Gas supply delivered to Manitoba. The Distribution PGVA also includes charges on the Minell pipeline as an inflow to this account.

Schedule 10.4.4(a) sets out the monthly detail for the account. The Distribution PGVA balance as at October 31, 2011 is $0.5 million owing to customers (line 16). Schedule 10.4.4(a) carries forward the balance of this account to July 31, 2013, as Centra is requesting new non-Primary Gas base rates effective August 1, 2013. With the inclusion of carrying costs for the months from November 2011 through July 2013, the July 31, 2013 balance in this account is $0.5 million owing to customers, as shown on line 42.

Schedule 10.4.4(b) shows a comparison of actual and approved annual cost inflows and outflows for the account. UFG cost inflows into this account from the Primary Gas and Supplemental Gas PGVA's were $0.4 million greater than forecast. This is mainly a result of the UFG true-up calculated in June 2011 for the period from June 1, 2010 to May 31, 2011. A transfer of $0.4 million was made from the Primary Gas and Supplemental Gas PGVA's into the Distribution PGVA, as shown on line 4 of Schedule 10.4.4(b), due to the higher than forecast UFG experienced during the period. The actual UFG percentage of 1.01% for the months of June 2010 through May 2011 was greater than the forecast of 0.90%.

WACOG outflows from the Distribution PGVA were $0.9 million greater than the approved forecast (Schedule 10.4.4(b), line 10). Greater WACOG outflows are mainly the result of the approved May 1, 2010 Distribution rates remaining in effect through April 30, 2011, whereby the embedded commodity costs were greater than those embedded in the approved Distribution base rates flowing from Centra's 2011/12 Cost of Gas Application that came into effect on May 1, 2011.

The net residual balance of $0.5 million owing to customers at October 31, 2011 is shown on line 29 of Schedule 10.4.4(a). The addition of carrying cost for the months from November 2011 through July 2013 results in a balance in the 2010/11 Gas Year Distribution PGVA of $0.5 million owing to customers on July 31, 2013, as displayed on line 42 of Schedule 10.4.4(a).

10.5 2010/11 Gas Year Hedging Activities

Centra exited its quarterly Primary Gas hedging activity in compliance with Order 170/09. No Primary Gas hedges were placed after the July 6, 2010 hedging session, in accordance with PUB Orders 170/09 and 93/10. The impact of the quarterly Primary Gas derivatives placed for the 2010/11 Gas Year was a net gas cost addition of $18.9 million. The specifics of all derivatives hedging transactions pertaining to the 2010/11 Gas Year are detailed in Schedule 10.5.0.

In January 2010, Centra placed hedges on two separate days, each comprising 37.5% of eligible Primary Gas volumes. Both sets of transactions were placed for the months of November 2010 through January 2011. On January 8, 2010, cashless price collars with 15% OTM upper bandwidths were purchased on 37.5% of eligible volumes. The instruments placed on January 8th had upper strike prices set at +$0.825 out-of-the-money ("OTM") for November 2010 and +$0.975 OTM for both December 2010 and January 2011, with their corresponding lower strike prices ranging from -$0.550 to -

\$0.673 OTM. The January 13th instruments' 15% OTM upper strike prices were set at +\$0.825 OTM for November 2010 and +\$0.975 OTM for both December 2010 and January 2011. The corresponding lower strike prices on these collars ranged between -\$0.565 and -\$0.690 OTM.

On April 21, 2010, hedges were executed on 50% of eligible volumes for the months of February 2011 through April 2011. The instruments placed bore 15% OTM upper strike prices set at +\$0.675 OTM for all three months hedged. The corresponding lower strike prices on these hedges ranged between -\$0.440 OTM and -\$0.485 OTM.

On July 6, 2010, hedges were placed on 25% of eligible volumes for the months of May 2011 through July 2011. The 15% OTM upper strikes on all instruments were set at +\$0.675 OTM. The corresponding lower strike prices on these instruments ranged between -\$0.465 OTM and -\$0.485 OTM.

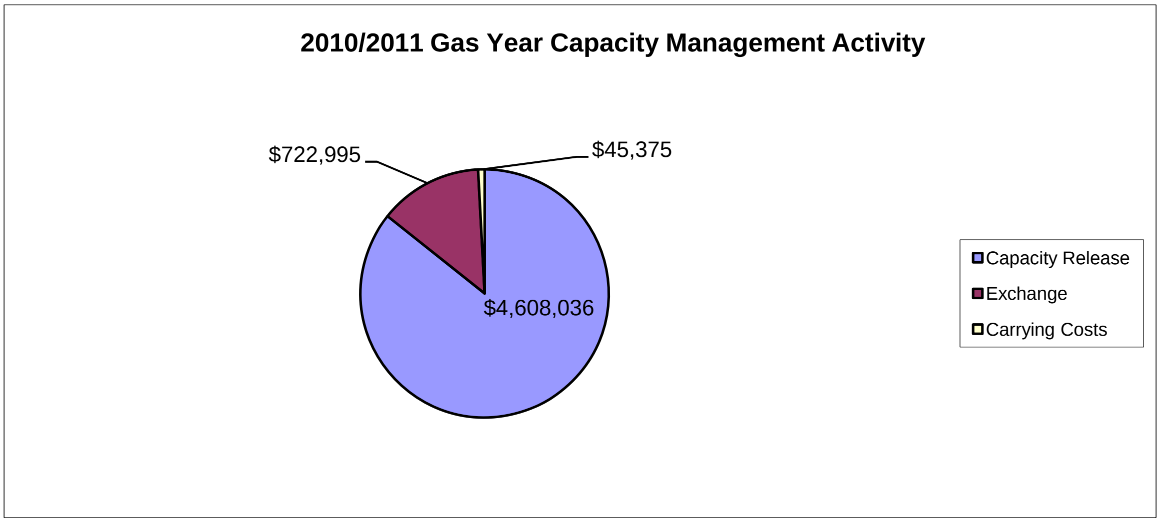
No pre-paid premiums were required for the hedging transactions discussed above.

10.6 2010/11 Gas Year Capacity Management

Section 10.2 provides a description of CM. This section outlines the CM revenues for the 2010/11 Gas Year.

10.6.1 2010/11 Gas Year Capacity Management Activities and Results

Total CM revenues for the 2010/11 Gas Year (excluding carrying costs) were $5.3 million. The specific component breakdown of these revenues by activity type is detailed in the following chart.



Actual CM revenues, excluding carrying costs, were $1.6 million less than the budget of $6.9 million as per the five-year average of actual results covering the period of November 1, 2005 through October 31, 2010.

The 2010/11 Gas Year CM revenues, which netted to a credit of $5.4 million after the inclusion of carrying costs, were accumulated in a separate deferral account for internal control purposes and were then closed out to the 2010/11 Gas Year Transportation PGVA after the conclusion of the 2010/11 Gas Year period. The Transportation base rates that came into effect on May 1, 2011 included an embedded amount of $6.9 million for CM revenues forecast for the 2010/11 Gas Year. 2010/11 Gas Year CM revenues are detailed by individual transaction type in Schedule 10.6.1. Results by calendar month during the 2010/11 Gas Year are shown in Schedule 10.6.2.

10.6.2 2010/11 Gas Year Capacity Release

Net capacity release revenues of $4.6 million were realized in the 2010/11 Gas Year (Schedule 10.6.1, line 4). The availability of markets downstream of Manitoba requiring transportation made these transactions feasible.

10.6.3 2010/11 Gas Year Exchanges

2010/11 Gas Year CM exchanges generated $0.7 million in net revenues (Schedule 10.6.1, line 8). A favourable basis differential between Manitoba and downstream markets made these transactions feasible.

10.7 Other Gas Cost Deferral Balances for 2010/11 Gas Year

10.7.1 2010/11 Gas Year Heating Value Margin Deferral Account

The approved rates for the 2010/11 Gas Year were based on a gas heating value of 37.8 $GJ/10^3m^3$. As actual gas heating values for the 2010/11 Gas Year period averaged lower than this embedded amount a balance of $0.8 million owing to customers accumulated through October 31, 2011. The addition of carrying costs for the months from November 2011 through July 2013 results in the balance of $0.8 million owing to customers as displayed on line 37 of Schedule 10.7.1.

10.7.2 April 30, 2011 Prior-Period Gas Deferrals Account

The April 30, 2011 Prior-Period Gas Cost Deferrals Account is comprised of residual balances from 2009/10 Gas Year deferral accounts and the April 30, 2010 Prior-Period Gas Deferral account as detailed on lines 1 to 9 of Schedule 10.7.2(a).

Rate riders designed to recover the balance in the April 30, 2011 Prior-Period Gas Cost Deferrals Account were approved in Order 66/11 for implementation on May 1, 2011. Centra transferred the residual balance in the April 30, 2010 Prior-Period Gas Cost Deferral Account, along with the final balances in the 2009/10 Gas Year PGVA's and Heating Value Margin Deferral Account, to the April 30, 2011 Prior-Period Gas Cost Deferral Account in order to bundle all approved prior-period gas cost deferrals into a single account to track the recovery of the net deferral balance over the subsequent 12-month period by way of rate riders implemented on May 1, 2011.

The cumulative actual April 30, 2011 net balance in these various deferral accounts totalled $4.6 million owing to Centra as identified on line 9 of Schedule 10.7.2(a). This compares to the estimated balance for these accounts of $4.5 million owing to Centra as approved in Order 66/11. The individual approved and actual account balances, and explanations of the differences between the approved and actual figures, are detailed on lines 1 through 7 of Schedule 10.7.2(a).

Recovery of the balance in the April 30, 2011 Prior-Period Gas Cost Deferral Account began on May 1, 2011 when rate riders approved in Order 66/11 came into effect. The actual $0.7 million residual debit balance in this account on April 30, 2012 as identified on line 15 of Schedule 10.7.2(b) was due to warmer than normal weather for the amortization period of May 2011 through April 2012, resulting in a net reduction to rate rider collections from customers. The associated rate riders were removed effective May 1, 2012 as approved in Order 54/12. Centra intends to transfer the July 31, 2013 residual debit balance of $0.8 million recoverable from customers including carrying costs (Schedule 10.7.2(b), line 41), along with the residual balances in all other previously discussed 2010/11 Gas Year non-Primary Gas cost deferral accounts to the July 31, 2013 Prior-Period Gas Cost Deferral Account to facilitate the disposition of all prior-period gas cost deferral balances with rate riders to become effective on August 1, 2013 for a subsequent twelve-month period.

10.8 Description of 2011/12 Gas Year Costs and PGVAs

On November 1, 2011, new non-Primary Gas PGVA and other gas cost deferral accounts were created to accumulate gas cost deferral inflows and outflows during Centra's 2011/12 Gas Year from November 1, 2011 to October 31, 2012.

The Primary Gas, Supplemental Gas, and Distribution PGVA balances for the months of November 2011 through May 2012 have incorporated an actual UFG percentage of 0.52% of total receipts into the Centra system, based upon the 12-month UFG true-up that was conducted in the summer of 2012.

Schedule 10.8.0 displays the 2011/12 Gas Year actual costs relative to the approved forecast. Line 63 of Schedule 10.8.0 indicates actual costs for the 2011/12 Gas Year total $160.1 million in comparison to the forecast of $248.0 million as approved through PUB Order 66/11.

10.8.1 2011/12 Gas Year Primary Gas PGVA

As noted previously, details pertaining to the Primary Gas PGVA for the period from November 1, 2011 to October 31, 2012 have been provided for information purposes only. While Centra is requesting final approval of actual Primary Gas costs for the Gas Year 2011/12, it is not seeking any change to Primary Gas rates in this Application as Primary Gas rates are adjusted each quarter through Primary Gas rate applications using the RSM approved by the PUB.

Schedule 10.8.1 sets out the monthly detail for the account. The total October 31, 2012 balance, including carrying costs, is $25.4 million owing to customers as shown on line 25 of Schedule 10.8.1. The cost inflows and outflows are based on actual results to October 31, 2012. As discussed in section 10.4.1, no variance analysis of the Primary Gas PGVA is provided within this Application.

10.8.2 2011/12 Gas Year Supplemental PGVA

Schedule 10.8.2(a) sets out the monthly detail for the account. The cost inflows and outflows are based on actual results from November 1, 2011 to October 31, 2012. The October 31, 2012 balance is $0.7 million owing to customers (line 23).

Schedule 10.8.2(b) shows a comparison of actual and approved Supplemental Gas PGVA inflows and outflows, which helps to identify the major contributors to the residual balance. Supplemental cost inflows, net of UFG costs transferred to the Distribution PGVA, were $32.9 million less than approved costs (line 12).

Line 2 of Schedule 10.8.2(b) provides a comparison of actual and approved Oklahoma supply costs. Inflows were $1.9 million less than forecast, where $1.8 million of the total variance is attributable to purchases that were 464,000 GJs less than forecast due to warmer than normal weather during the 2011/12 Gas Year. The remaining $0.1 million variance pertains to approved forecast prices that utilized a November 1, 2010 futures price strip as compared to actual average index prices for supplies that were lower than forecast.

Referring to line 3 of Schedule 10.8.2(b), Supplemental Gas storage utilization was $0.2 million less than forecast. Actual weather during the November 2011 through March 2012 period was 20% warmer than normal (based on effective heating degree days), thus eliminating the requirement to withdraw any Supplemental Gas supplies from storage.

Line 5 of Schedule 10.8.2(b) shows a $31.9 million variance related to Supplemental Gas Peaking Delivered Service. 9.9 million GJ's of Supplemental Gas Peaking Delivered Service purchases were forecast for the 2010/11 Gas Year. By comparison, actual purchases for the 2011/12 Gas Year totalled 843,968 GJ's. The lower Supplemental Gas Peaking Delivered Service purchase volumes resulted in Supplemental inflows that were $31.1 million less than the approved forecast. In addition, the remaining $0.8 million variance relates to lower than forecast average per unit commodity costs for these supply purchases.

Lines 6 of Schedule 10.8.2(b) displays the $0.5 million of Alternate Supply Service acquired for Interruptible customers in lieu of curtailment in the months of April and October 2012. In the 2011/12 Gas Year, 181,032 GJ's of Alternate Supply Service purchases were required. Forecast Interruptible consumption over and above pre-contracted supplies is considered to be curtailed and therefore, Alternate Supply Service is not included in the forecast.

Line 10 of Schedule 10.8.2(b) compares the forecast versus actual Supplemental UFG component transferred to the Distribution PGVA. Supplemental Gas UFG transfers were $0.5 million below forecast due to actual Supplemental Gas purchase volumes being 9.4 million GJ's less than approved, along with an additional small component due to the lower than forecast natural gas commodity prices as noted in Schedule 10.8.2(b), lines 23 and 24.

Line 11 of Schedule 10.8.2(b) presents the transfer of Supplemental Gas cost inflows pertaining to the UFG True-up, where $0.02 million were reallocated from the Distribution PGVA as the actual UFG percentage of 0.52 % for the months of June 2011 through May 2012 was less than the 0.90% forecast.

Total Supplemental Gas PGVA Inflows, as indicated on Schedule 10.8.2(b) line 12, were $32.9 million less than the 2010/11 Gas Year approved forecast.

Schedule 10.8.2(b), line 15, compares actual versus forecast Supplemental Gas PGVA WACOG outflows that were $32.8 million less than forecast, which is mainly attributable to the previously discussed warmer than normal 2011/12 winter weather and correspondingly lower customer consumption.

Line 16 of schedule 10.8.2 (b) identifies the corresponding WACOG outflow related to Alternate Supply Service volumes delivered to Interruptible customers in lieu of curtailment in April and October 2012. Costs incurred relating to Alternate Supply Service are recovered from customers electing to take the service and therefore, line 16 and line 6 of Schedule 10.8.2(b) correspond directly to one another. As Alternate Supply Service is not forecast, WACOG outflows are $0.5 million greater than forecast as a result.

Total Supplemental Gas PGVA outflows, as indicated on Schedule 10.8.2(b) line 17, were $32.3 million less than forecast.

The 2011/12 Gas Year Supplemental PGVA cost inflows and outflows are based on actual results for the period from November 1, 2011 to October 31, 2012. The actual Supplemental Gas PGVA balance at October 31, 2012, as indicated on line 23 of Schedule 10.8.2(a), is $0.7 million owing to customers. The addition of carrying costs for the months from November 2012 through July 2013 results in the balance of $0.7 million owing to customers displayed on line 39 of Schedule 10.8.2(a).

10.8.3 2011/12 Gas Year Transportation PGVA

Schedule 10.8.3(a) sets out the monthly detail for the 2011/12 Gas Year Transportation PGVA. The total October 31, 2012 balance is $5.6 million owing to Centra as shown on line 21. The 2011/12 Gas Year Transportation PGVA cost inflows and outflows are based on actual results for the period of November 1, 2011 to October 31, 2012.

Schedule 10.8.3(b) shows a comparison of 2011/12 actual versus 2010/11 approved Transportation PGVA cost inflows and outflows.

Total fixed transportation cost inflows (Line 2 of Schedule 10.8.3(b)) were $6.4 million less than forecast. This variance is a result of continued de-contracting of firm transportation capacity on the TransCanada Mainline relative to the 2010/11 approved forecast. In months where Centra was able to utilize Primary Gas Delivered Service (see Schedule 10.8.1 line 3) and achieve a lower overall net landed cost of gas compared to incurring fixed contract demand charges with TransCanada, Centra reduced its fixed pipeline demand charges by a total of $8.9 million as compared to the 2010/11 Gas Year budget. Throughout the 2011/12 Gas Year Centra faced higher TCPL Demand Tolls, increasing fixed costs as compared to budget by $2.6 million. Slightly favourable US exchange rate variances for the 2011/12 Gas Year reduced fixed transportation costs by $0.1 million relative to forecast. For the 2010/11 Gas Year, the exchange rate was forecast at an average of $1.01 CDN/USD in comparison to the actual average exchange rate of $1.00 CDN/USD.

Line 3 of Schedule 10.8.3(b) indicates that variable transportation cost inflows were $0.04 million less than approved. The main contributor to this variance was reduced TCPL variable charges as a result of replacing Firm Mainline transportation with Primary Gas Delivered Service.

Lines 4 and 5 of Schedule 10.8.3(b) denote the variances associated with imputed transportation costs on both Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Services. These matters were discussed previously in Sections 10.4.2 and 10.4.3. As Centra continues to mitigate its exposure to increasing tolls on the TCPL Mainline, Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Services have played an increasing role in Centra's commodity purchases.

Line 4 of Schedule 10.8.3(b) pertains to Supplemental Gas Peaking Delivered Service Imputed Transportation Costs that were $4.1 million lower than the 2010/11 approved forecast. There were no Supplemental Gas Peaking Delivered Service purchases during the 2011/12 Gas Year due to the previously noted much warmer than normal weather.

Primary Gas Delivered Service Imputed Transportation Costs were $10.7 million greater than the 2010/11 Gas Year approved budget figures (line 5 of Schedule 10.8.3(b). Centra continued to actively manage its portfolio during the 2011/12 Gas Year in order to further mitigate its exposure to increasing tolls on the TCPL Mainline.

Schedule 10.8.3(b), line 6, Storage Gas Transportation and Delivery Costs were $0.8 million less than approved. Actual weather in the November through March 2012 period was warmer than normal, therefore requiring fewer withdrawals from Centra's storage to meet the winter load.

Line 8 of Schedule 10.8.3(b) indicates that actual 2011/12 Gas Year CM revenues were less than the approved 2010/11 Gas Year forecast by $0.5 million. CM revenues are discussed in detail in Section 10.9 below.

In summary, actual inflows to the 2011/12 Gas Year Transportation PGVA were $0.05 million less than the approved 2010/11 Gas Year forecast as identified on Schedule 10.8.3(b), line 10.

Line 13 of Schedule 10.8.3(b) indicates that WACOG outflows from the Transportation PGVA were $5.7 million less than approved as a result of actual throughput volumes being lower than forecast due to warmer than normal weather experienced during the 2011/12 Gas Year.

The net accumulation in the 2011/12 Gas Year Transportation PGVA is a balance of $5.6 million owing to Centra as of October 31, 2012 as shown on Schedule 10.8.3(a), line 21. The addition of carrying costs for the months from November 2012 through July 2013 results in the balance of $5.7 million owing to Centra as shown on line 34 of Schedule 10.8.3(a).

10.8.4 2011/12 Gas Year Distribution PGVA

Schedule 10.8.4(a) sets out the monthly detail for the account. The Distribution PGVA balance as at October 31, 2012, equates to $1.7 million owing to customers (line 16).

Schedule 10.8.4(b) provides a comparison of actual and approved annual cost inflows and outflows for the account. UFG cost inflows into this account from the Primary Gas and Supplemental Gas PGVA's were $ 2.0 million less than forecast.

$1.2 million of this variance (line 3) is attributable to reduced volume throughput as a result of warmer than normal weather experienced in the 2011/12 Gas Year. Total volume purchases excluding broker delivered Primary Gas were 7.1 million GJ less than approved forecast volumes as shown on Schedule 10.8.0, line 72.

The remaining $0.8 million of the 2011/12 Gas Year Distribution PGVA inflow variance is the result of the UFG true-up calculated in June 2012 for the period from June 1, 2011 to May 31, 2012. $0.8 million was transferred from the Distribution PGVA to the Primary Gas and Supplemental Gas PGVA's, as shown on line 4 of Schedule 10.8.4(b), due to the lower than forecast UFG experienced during the period. The actual UFG percentage of 0.52% for the months of June 2011 through May 2012 was less than the forecast of 0.90%.

WACOG outflows from the Distribution PGVA were $0.3 million lower than the approved forecast (Schedule 10.8.4(b), line 10) mainly as a result of the warmer than normal weather experienced in the 2011/12 Gas Year.

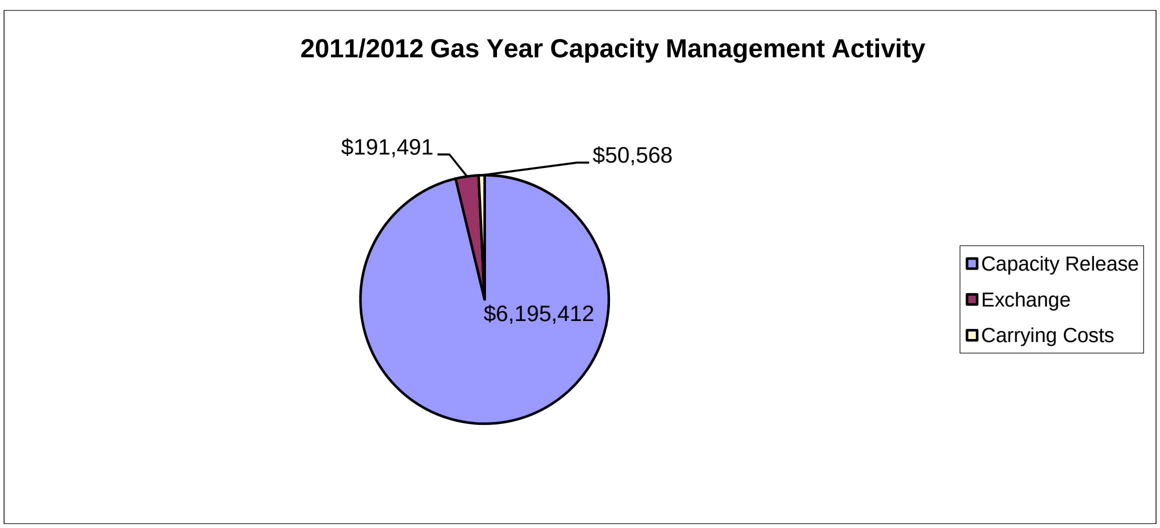
The 2011/12 Gas Year Distribution PGVA's net residual balance of $1.7 million owing to customers at October 31, 2012 is shown on line 16 of Schedule 10.8.4(a). The addition of carrying costs for the months from November 2012 through July 2013 results in the balance of $1.7 million owing to customers as displayed on line 33 of Schedule 10.6.4(a).

10.9 2011/12 Gas Year Capacity Management

Centra undertook CM activities throughout the 2011/12 Gas Year in the same manner as described in section 10.6 of this Application.

10.9.1 2011/12 Gas Year Capacity Management Activities and Results

Total CM revenues for the 2011/12 Gas Year (excluding carrying costs) were $6.4 million. The specific component breakdown of these revenues by activity type is detailed in the following chart.



Actual CM revenues, excluding carrying costs, were $0.5 million less than the 2010/11 Gas Year approved amount of $6.9 million. The 2011/12 Gas Year CM revenues, which netted to $6.4 million including carrying costs, were accumulated in a separate deferral account for internal control purposes and were then closed out to the 2011/12 Gas Year Transportation PGVA after the conclusion of the 2011/12 Gas Year. 2011/12 Gas Year CM revenues are detailed by individual transaction type in Schedule 10.9.1. Results by calendar month during the 2011/12 Gas Year are shown in Schedule 10.9.2.

10.9.2 2011/12 Gas Year Capacity Release

Net capacity release revenues of $6.2 million were realized in the 2011/12 Gas Year (Schedule 10.9.1, line 4). The availability of markets downstream of Manitoba requiring transportation made these transactions feasible.

10.9.3 2011/12 Gas Year Exchanges

2011/12 Gas Year Capacity Management exchanges generated $0.2 million in net revenues (Schedule 10.9.1, line 8). A favourable basis differential between Manitoba and downstream markets made these transactions feasible.

10.10 Other Gas Cost Deferral Balances for 2011/12 Gas Year

10.10.1 2011/12 Gas Year Heating Value Margin Deferral Account

Approved rates are based on a gas heating value of 37.8 $GJ/10^3m^3$ and as actual gas heating values for the 2011/12 Gas Year period averaged lower than this embedded amount, a balance of $0.5 million owing to customers accumulated through October 31, 2012 as displayed on line 11 of Schedule 10.10.1. The addition of carrying costs for the months from November 2012 through July 2013 results in a balance of $0.5 million owing to customers as displayed on line 28 of Schedule 10.10.1.

10.11 Summary of All Prior-Period Gas Cost Deferral Balances to July 31, 2013

Schedule 10.11.0 provides a summary of all gas cost deferral balances to July 31, 2013. The total of all prior-period deferral balances equates to $0.01 million owing to Centra as at July 31, 2013, as indicated on line 24 of Schedule 10.11.0. Centra is requesting the approval of the associated rate riders to recover this amount from customers over the 12-month period beginning August 1, 2013.

The allocation of the July 31, 2013 Prior-Period Gas Cost Deferral Account to the various customer classes and the calculation of rate riders to recover this balance in rates, as well as the resulting rate impacts by customer class will be provided in the Cost Allocation & Rate Design material in Tab 11 and the Rate Schedules and Customer Impacts shown in Tab 12 of this Application.

10.12 Description of Forecast 2012/13 Gas Year Costs

This section provides a discussion and estimate of gas costs for the forecast period of November 1, 2012 to October 31, 2013. The forecast gas cost information contained in this Section is used in preparing the new base rates for Centra’s Supplemental Gas, Transportation (to Centra) and the UFG component of Distribution rates to be effective August 1, 2013.

The gas cost forecast in this Application incorporates settled market index prices for November 2012, with all other months based on futures market prices as of the November 1, 2012 market close. Pipeline tolls are based on the 2012 toll levels carried forward for the entire Gas Year. Consumption volumes and customer numbers from November 1, 2012 to October 31, 2013 are based on Centra's most recent normal weather customer and volume forecast as provided in Tab 8.

The gas cost estimate considers forecast purchase volumes based on Centra's projection of Sales Service (Centra supply and Marketer supply under WTS) and Transportation Service volumes. Total purchase volumes were developed from the estimate of normal sales volumes considering UFG amounts equal to 0.9% of total system receipts. This UFG factor represents long-term historical data and is reflective of typical UFG losses.

Natural gas market prices continue to remain at or near decade lows in response to the growth in production of unconventional gas supplies, including prolific shale gas plays in multiple U.S. jurisdictions, as well as significant technological advances achieved by the exploration and production industry in general.

10.12.1 Primary Gas Supply

Western Canadian supply costs for Primary Gas for the forecast period from November 1, 2012 to October 31, 2013 are based on the terms of Centra's current Primary Gas supply contract, which became effective on November 1, 2012. Monthly Primary Gas supply prices direct to the load are forecast to range between $2.96/GJ and $3.35/GJ for the period of November 1, 2012 to October 31, 2013 as provided on Schedule 10.12.1 line 43.

10.12.2 Primary Gas Swing Load Purchases

Pricing for Primary Gas Swing Load purchases reflect the terms for Swing Load service under Centra's current Primary Gas supply contract. The Swing Load gas pricing is indexed to daily AECO spot prices for Swing Load volumes purchased on any given day.

10.12.3 Oklahoma Supply

Oklahoma supply prices incorporate settled November 2012 index pricing, plus November 1, 2012 futures market prices for December 1, 2012 to March 31, 2013. Oklahoma supply prices for deliveries directly to the Manitoba load for the period from November 1, 2012 to March 31, 2013 are forecast to range between $3.10/GJ and $3.44/GJ as provided on Schedule 10.12.1 line 45. Centra's Oklahoma ANR transportation contract concludes as of March 31, 2013.

10.12.4 Emerson Supply

Emerson supply prices are based on settled index pricing for the month of November 2012 and November 1, 2012 futures strip prices for the period from December 1, 2012 through October 31, 2013. Emerson supply prices for deliveries either to the Manitoba load or for storage injection for the period from November 1, 2012 to October 31, 2013 are forecast to range from $3.53/GJ to $3.88/GJ as provided on Schedule 10.12.1 line 48.

10.12.5 Chicago Supply

The new Gas Portfolio includes a new ANR storage transportation contract that allows Centra to move gas from the ANR Joliet delivery point to the ANR storage injection point. Given their close physical proximity to one another, forecast prices for ANR Joliet purchases use Chicago market hub futures prices as a proxy in the absence of an exchange traded ANR Joliet futures contract. Chicago futures market prices as at November 1, 2012 for the storage injection period from April 1, 2013 to October 31, 2013 are forecast to range from $3.63/GJ to $3.78/GJ as provided on Schedule 10.12.1 line 49.

10.12.6 Uncontracted Supplies

Under normal weather conditions, approximately 35,319 GJ of uncontracted supply is forecast to be required to meet the Interruptible load during the 2012/13 Gas Year. This supply requirement is excess to that available to serve the system load by means of TCPL operating demand levels, Oklahoma supplies, Emerson supplies, and storage withdrawal capabilities. These volumes represent the amount of curtailment that is forecast, on a normal weather basis, for Interruptible customers. As such, these curtailment volumes have been excluded from the 2012/13 gas cost forecast. Uncontracted supplies are purchased on a day-to-day basis as required, typically as a Delivered Service, and those costs are directly recovered from those Interruptible customers that elect Alternate Supply Service.

10.12.7 Storage Withdrawals

Based on the actual balances in each of the gas storage accounts after the 2011/12 winter season, plus the actual fill costs during the summer of 2012, the final average inventory cost for each component as at October 31, 2012 is as follows:

Primary Gas Supply in storage:	$2.813 CAD/GJ
Supplemental Gas Supply in storage:	$4.703 CAD/GJ
Transportation costs inventoried:	$0.1681 CAD/GJ

The cost of the forecast storage withdrawals for the 2012/13 winter season is determined using these average inventory costs.

10.12.8 Transportation and Storage Costs

TCPL transportation costs for the entire 2012/13 Gas Year forecast period of November 1, 2012 to October 31, 2013 are based on the TCPL approved interim tolls that came into effect on January 1, 2012 and are provided in Schedule 10.12.1.

U.S. storage and pipeline tolls for ANR Pipeline and GLGT are based on current tolls and contracting levels for the November 1, 2012 through March 31, 2013 period. The tolls and costs associated with Centra's new seven-year U.S. transportation and storage portfolio have been incorporated into the 2012/13 Gas Year forecast for the period of April 1, 2013 through October 31, 2013.

10.12.9 U.S. Exchange Rate

For November 2012, the exchange rate applied to U.S. gas purchases and U.S. transportation and storage costs is the actual exchange rate of $0.99 CAD/USD. A forecast exchange rate of $1.00 CAD/USD is utilized for the December 1, 2012 to March 31, 2013 period, while an exchange rate of $0.99 CAD/USD has been forecast for the period of April 1, 2013 through October 31, 2013.

10.12.10 Resulting Gas Costs for 2012/13 Gas Year

The total cost of gas forecast for the Gas Year from November 1, 2012 to October 31, 2013 is $204.2 million including forecast CM revenues of $6.3 million (discussed in Section 10.12.12 below). The details of these calculations are shown in Schedules 10.12.1 through 10.12.3 (a) and (b).

Schedule 10.12.1 summarizes the fixed and variable transportation unit costs, unit supply prices and fuel ratios. Schedule 10.12.2 summarizes contract demand levels and volumes by supply type supplied to the Manitoba load. Schedules 10.12.3(a) and (b) summarize total gas costs grouped into fixed costs, variable transportation costs, supply costs and other costs.

10.12.11 2012/13 Forecast Gas Year Capacity Management

The forecast of CM revenues equates to $6.3 million for the 2012/13 Gas Year. This amount is based on the most recent 60-month rolling average of Centra's actual CM results. The rolling 60-month calculation uses actual CM results from November 1, 2007 to October 31, 2012. By comparison, the approved 2010/11 Gas Year cost forecast incorporated forecast CM revenues of $6.9 million.