MANITOBA PUBLIC UTILITIES BOARD

CENTRA GAS MANITOBA INC.

COST OF SERVICE METHDOLOGY REVIEW APPLICATION

THE PUBLIC UTILITIES BOARD
Exhibit No. CAC-13
Re: Centra 2021 COSS

DATE SECRETARY

Book of Documents of

Consumers' Association of Canada (Manitoba Inc.) (CAC)

August 17, 2022

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Board Order 107/96

The last comprehensive review of the natural gas COS and rate design occurred in 1996 and resulted in Order 107/96. The following excerpts from Order 107/96, summarize the key PUB policy findings with respect to the last natural gas COS review:

"The Board will expect such a review to consider the appropriateness of all methods and systems to be employed to functionalize and classify all capital and operating costs and allocate such costs to proper customer class definitions. The Board further expects that the **primary driver** will be **cost causation** with due regard to Centra's current operations in the Manitoba market, direct purchase activities, storage arrangements, risk management activities, **weather** and **use patterns** for each specific customer class and all **other relevant issues.**[1]" (Emphasis added)

"**Cost allocation studies** are **not a precise science** and **contain elements of judgement at most phases.** Cost allocation methodologies are numerous, and experts often have differing opinions as to the appropriate manner of allocating costs of service. It is the **Board's responsibility to weigh those differing views** and to support a methodology which gives the best guideline for determining just and reasonable rates, and which is not unduly discriminatory, recognizing that subjective judgements will influence results...This public hearing was to allow debate of these opinions and to arrive at a methodology which best reflects the Manitoba circumstance...The Board's expectation is that the principles herein approved will be adaptable to industry changes and that the results produced should be acceptable for some time into the future...The Board also agrees that the **cost of service methodology best suited** for a natural gas distribution company should be **determined based upon** the **circumstances** of the **utility.** Those **circumstances must reflect** the **manner** in which the **system** is **designed as well as** the **manner in which the system is operated. Giving some weight** to the **manner of system operation better reflects the cost responsibility than does a methodology** which **considers** only the **design parameters.** For example, a system may be designed to interrupt particular customers on a peak day so that firm customers can continue to receive service. Should the peak not be met, however, those interruptible customers continue to receive service...Even though a design contemplates curtailment of interruptible customers, it cannot preclude a movement of customers from firm to interruptible service or vice versa. The Board is of the view that Centra's proposal for the use of demand related cost allocators based on the Peak and Average Methodology best reflects the appropriate treatment for all Manitoba natural gas consumers, that it reflects current market conditions and is adaptable to change.[2]" (Emphasis added)

[1] Order 107/96, Page 6

[2] Order 107/96, Pages 26 to 27

Board Order 164/16

The last comprehensive review of the electric COS occurred in 2016 and resulted in Order 164/16. The following excerpts from Order 164/16, summarize the key PUB policy findings with respect to the last electric COS review:

"The Board finds that, in the process to **determine the appropriate COSS methodology**, the **principle** of **cost causation** is **paramount**...The Board finds that **Manitoba Hydro's ratemaking principles and goals** of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be **considered** in a **General Rate Application** ("GRA") **and not** in the **cost of service methodology...Cost causation as defined** by the **Board** takes into **consideration both how** an **asset is planned** and **how that asset is used.** This **takes into account** how an asset fits into Manitoba Hydro's **current system planning,** as well as the **current use**...The Board also finds that **cost causation requires consideration** of **all** the **uses** and **benefits** of an asset, to **recognize** that **both primary** and **secondary benefits** influence the planning and justification of assets. These **considerations** should be **assessed over** a **range of years** (as opposed to a single forecasted year) and **over** a **range of conditions** in order to **capture all** of the **uses and benefits** of an **asset** in **determining cost causation.**[3] (Emphasis added)

[3] Order 164/16, page 27

Centra Operational (Use) Costs/Benefits Examples:

1. Maintain or enhance reliability by providing redundancy for transmission and distribution vulnerable to an extended loss of supply due to damage;
2. Operational flexibility – to shift load from heavily-utilized pipelines to under-utilized pipelines;
3. Operational flexibility – to permit inspections, maintenance or construction activities including for aging pipelines;
4. Minimize the incremental costs associated with outages;
5. Minimize excessive usage of the electric system during natural gas outages particularly in areas where the electric system is already at capacity and may result in cascading electrical system outages;
6. Capacity Management revenues;
7. Diversification and risk management benefits for reliability purposes - to moderate the potential for system outages by reliance on only one commodity feed (such as TCPL); and,
8. Lower commodity costs – the use of storage allows for all system supply customers to benefit from lower commodity costs – through storing potentially less costly commodity in the summer (when demand is low). Commodity costs have been socialized and all customers pay the same rate.

Public Utilities Board

Régie des services publics

Order No. 36/22

SECOND PROCEDURAL ORDER IN RESPECT OF CENTRA GAS MANITOBA INC.'S COST OF SERVICE STUDY METHODOLOGY REVIEW APPLICATION

April 7, 2022

BEFORE: Larry Ring, Q.C., Panel Chair
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Board Vice-Chair
Susan Nemec, FCA, FCPA, Member

Room 400 – 330 Portage Avenue
Winnipeg, MB R3C 0C4
www.pubmanitoba.ca

330, avenue Portage, pièce 400
Winnipeg (Manitoba) Canada R3C 0C4
www.pubmanitoba.ca

Based on the Parties' submissions, the Board finds that there is no need for Interveners' additional comprehensive reviews of the existing COSS methodology (or model) and for evaluating Atrium's report for completeness. Instead, Interveners are to focus their submissions on the appropriateness of Atrium's and Centra's COSS recommendations or provide alternative methodologies appropriate for Centra's specific circumstances in Manitoba, without the need to duplicate the extensive review already conducted by Atrium. If relied on in this proceeding, Interveners are to re-file (and not duplicate) their expert evidence, on the in-scope issues, previously filed in Centra's last General Rate Application.

The participation of Interveners in evidentiary steps in the public hearing process will also assist the Board, as this participation contributes to a robust, transparent, and evidence-based decision-making process.

With the expectation of focused Information Requests and thorough written Responses by Centra, the Board finds that one round of concurrent Information Requests separately to Centra and to Atrium will be appropriate. The Board's Rules of Practice and Procedure outline remedies available to the Parties should they consider Centra's responses to Information Requests inadequate. However, the Board encourages all Parties to work together informally to resolve issues arising from Information Requests and Responses to Information Requests, before bringing matters formally before the Board for resolution.

The Board also finds that pre-approval of Intervener Information Requests posed to Atrium and separately to Centra is not required. Parties are aware that Information Requests are limited to the in-scope issues and seek to clarify matters that will assist the Board in its understanding of the issues, avoid duplication, and focus on the best practices for Centra's circumstances in Manitoba.

In addition, Parties need to be aware that when asking or answering any Information Requests that may contain confidential information, those questions and answers should initially only be provided to Centra and the Board to allow the Utility to determine whether

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name

Winnipeg Northwest Upgrade-Phase 2

Recommendation

The extension of an existing natural gas pipeline from the Rosser Station (GS-031) in Winnipeg to the City of Selkirk (GS-004) is necessary to provide additional capacity to the areas northwest of Winnipeg and to provide a redundant gas source to meet reliability and operational requirements in the Winnipeg natural gas transmission network. When compared to the alternatives, a single project combining the provision of additional capacity and redundancy is a financially efficient means of providing a reliable, resilient system suitable to meet the ongoing requirements and expectations of our customers.

The cost of this project is estimated at $31,100,000. The recommended in-service date (ISD) is October 15, 2016.

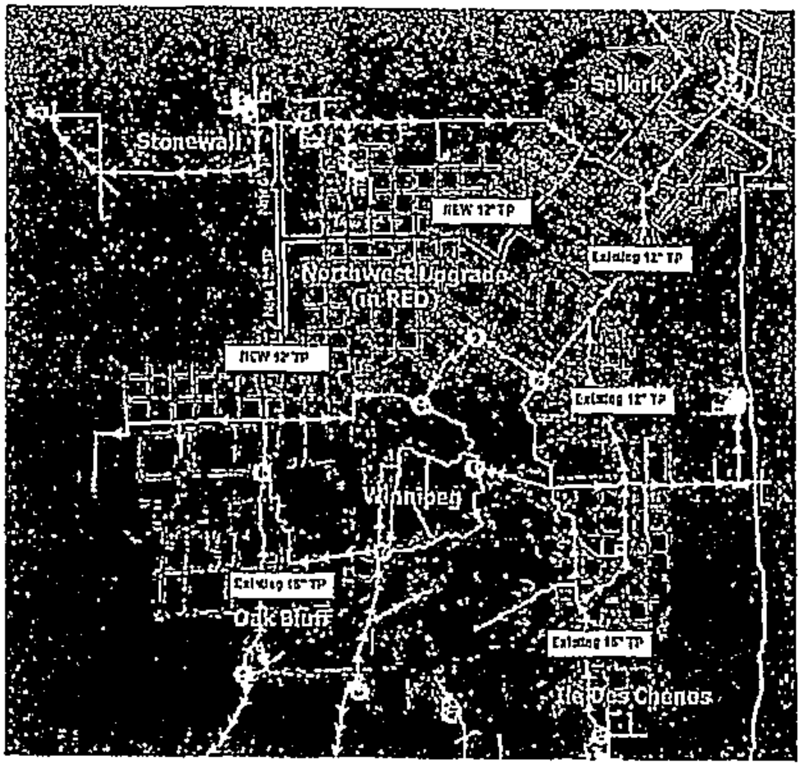
Project Scope

The Winnipeg Northwest Upgrade project is shown in Figure 1 and consists of the following:

- 19.8 km of NPS 12 steel transmission pressure (TP) pipe extending north from the Oak Bluff pipeline at Rosser Station GS-031.
- 6.6 km of NPS 6 steel TP pipe extending north from new TP to tie into the existing NPS 4 TP on Hwy 67 (Stonewall branch pipeline).
- 20.8 km of NPS 12 steel TP extending from the new NPS 12 TP going east and northeast to the Phase 1 Liss Rd Station, located in St. Andrews.
- 8.3 km of NPS 12 steel TP looping from Hwy 67 north along McPhillips Road to connect to the Ile des Chenes pipeline near regulating station GS-004 in Selkirk.
- Isolation valves as required for gas maintenance and operations.
- Pig launchers/receivers as required for pipeline integrity monitoring.

Project Scope

Figure 1 - Proposed Winnipeg Northwest Phase 2



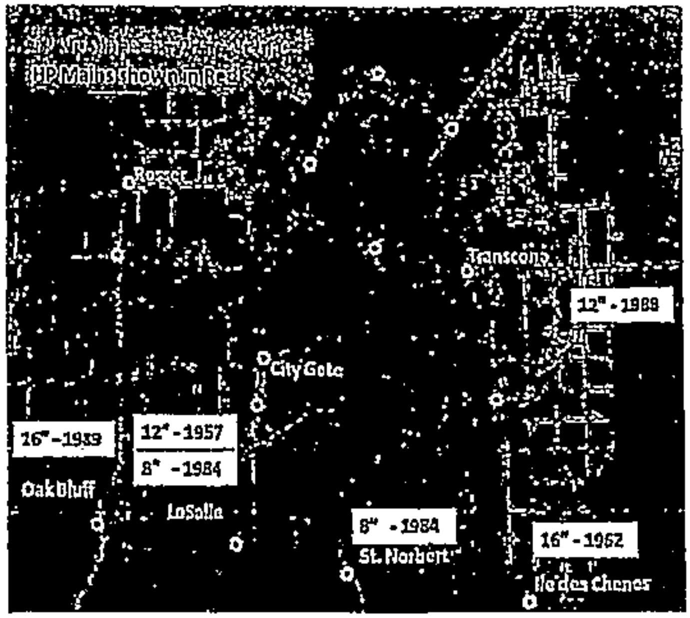
Background

There is insufficient capacity in the areas northwest of Winnipeg and unacceptably high velocities in the transmission main supplying Stonewall. The simple approach, on a stand-alone project basis, would be to install a sufficient length of new pipeline parallel to the existing Stonewall transmission line to split the load between the existing and new lines. However, the Stonewall transmission main and the area northwest of Winnipeg are supplied from the larger Winnipeg natural gas transmission system which necessitated a review of that system.

The Winnipeg natural gas transmission network consists of four systems feeding the City of Winnipeg and the communities north of Winnipeg supplied with natural gas. This system is the backbone of Manitoba Hydro's natural gas system serving over 213,000 or 80% of Hydro's gas customers. Figure 2 provides the general locations, size and age of installation of the four transmission supplies to the Winnipeg system.

Background

Figure 2 – Winnipeg TP and HP Networks

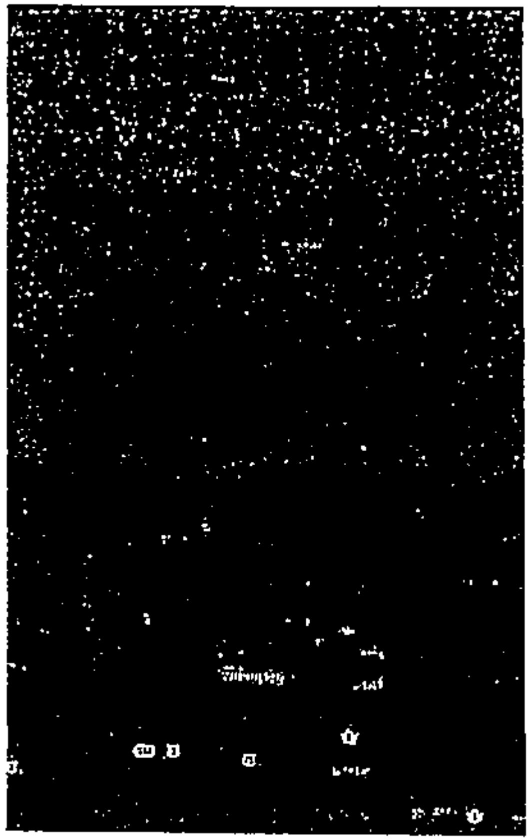


The review of the larger Winnipeg transmission system identified the following additional issues:

1. <u>Reliability</u>
   The Ile des Chenes system serves the high pressure loop in Winnipeg and continues north to supply customers east to Beausejour, west to Warren and north to Riverton. Figure 3 shows the communities and area supplied by the Winnipeg transmission systems. Outside of Winnipeg, this is a one-way feed system and these communities are vulnerable to a loss of supply due to damage anywhere along the line. It is estimated that a loss of supply on the Ile des Chenes line due to damage between the connection at the TCPL and Selkirk would result in the loss of 15,000 gas customers. This section of pipeline includes crossings of the Red and Seine Rivers, two crossings of the Winnipeg Floodway, two crossings of the Winnipeg Aqueduct, eight rail crossings and crossings of highways #1, 15, 44, 59, 202, 204 and multiple municipal and private roads. Access to the pipeline in these crossings will have physical or legal/jurisdictional restrictions that will delay returning the system to operation.

Background

Figure 3 - Areas Supplied by the Winnipeg Transmission Systems



2. Operational Flexibility
   There are no direct transmission pressure interconnects between the four transmission systems that supply Winnipeg, which does not meet the operational requirements of the corporation to accommodate maintenance, tie-ins, planned and unplanned outages.

3. System Loading and Reduction of Operating Pressure
   The peak loading on the 4 primary pipelines ranges significantly from 400, 4,100, 7,000 and 7,700 mcfh for St. Norbert, Oak Bluff, LaSalle and Ile des Chenes respectively. The loading is dependent on pipeline size, operating pressure and location. The St. Norbert pipeline is an 8" line running at high pressure. Both Ile des Chenes and Oak Bluff pipelines are 16" but Ile des Chenes supplies almost twice as much gas at design winter conditions. Shifting load from Ile des Chenes to Oak Bluff is necessary to increase the ability of the Ile des Chenes system to accept new growth while also permitting a reduction in system operating pressure. The pressure on the Ile des Chenes pipeline is currently set to suit the delivery of gas to Riverton (approximately 160 km from the Ile des Chenes primary) while also delivering the highest peak flow rate of the Winnipeg pipelines.

Background

4. Identified Transmission Capacity Issues
In addition to the current capacity issues identified in the Stonewall area, system growth at current levels is predicted to require the installation of significant amounts of additional pipe in several areas (lines from East Selkirk to Tyndall, and Selkirk to Gimli) within the next 5 to 10 years.

5. Maintenance
The current configuration of the transmission network is not adequate to perform required planned maintenance activities. The Ile des Chenes pipeline is 52 years old. With the pipeline being the only source of gas to a number of communities north of Winnipeg, it is not possible to take the pipeline out of operation to perform an in-line inspection to evaluate the pipeline condition and identify defects for repair.

6. Changes in TCPL Supply
Changes in the North America supply of and demand for natural gas have resulted in TCPL changing the supply of natural gas that is provided to Manitoba. The majority of natural gas provided to Manitoba is still from Alberta but TCPL does ship gas from the United States that enters Manitoba from TCPL's north-south lateral. This lateral connects to TCPL's east-west mainline immediately west of Ile des Chenes and the Ile des Chenes system is supplied with a blend of the US sourced gas. The southern gas quality is within the TCPL tariff but it does contain higher levels of water than western gas. The higher water levels increase the potential for water related issues (freeze-ups) at the pressure regulating stations on the Ile des Chenes line. Oak Bluff will continue to receive the dryer western gas.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

The rationale for completing this project are summarized as follows:

1. The requirement to correct high velocities in the Stonewall transmission branch and provide capacity in the area northwest of Winnipeg require modifications to the transmission system to provide new supply while maintaining system reliability. Combining these requirements while addressing other issues is an efficient means of improving the overall Winnipeg system.
2. To provide transmission capacity to serve the growth just north of Winnipeg for the next 20 years.
3. To provide the ability to shift load from the heavily-utilized pipeline on east side (Ile Des Chenes) of the City to the under-utilized pipeline on the west side of the City (Oak Bluff) and restore capacity in the City of Winnipeg system.
4. To provide full redundant supply to the communities north of Winnipeg and to provide a partial ability (approximately 1,000 mcfh) to back-feed the City of Winnipeg line in a loss of supply from either the Ile Des Chenes or Oak Bluff pipelines.
5. To improve operational flexibility to permit planned inspection, maintenance or construction activities.
6. The reactive approach where smaller projects are built in response to specific customer or system

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals

needs would result in approximately $21 million of projects that would be required in the next 5 to 10 years. While these projects would address capacity issues, they do not provide redundancy, or resolve any of the other issues identified. Meeting these other requirements would require an additional significant transmission investment which would be comparable in scope to the recommended course of action.

7. The June 20, 2014 PUB review of the Needs for and Alternatives to (NFAT) Review of Manitoba Hydro's Preferred Development Plan includes a recommendation that "*Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating*". The additional capacity provided by this project will readily support the addition of new customers in the area served.

The Winnipeg Northwest Upgrade project is Phase 2 of a project that is approved and will be constructed in 2014. The Phase 1 project addresses the local distribution issues in the St. Andrews area.

This project supports the corporate goals of maintaining capacity/system supply and providing customers with exceptional value through reliability of service.

ANALYSIS OF ALTERNATIVES:

Economic Analysis

Discount Rate	For current corporate rates see G911 5.40%	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	NPV Benefits (Costs)
The recommended option consists of 48.9 km of NPS 12 steel TP pipe, 6.6 km of NPS 6 steel TP pipe, and associated isolation valves and pig launchers/receivers as required for pipeline integrity monitoring. This option offered the best capacity to accommodate unforeseen loads, optimum ability to shift load and the highest redundant capacity in a planned or unplanned outage.	$28,034,000

Other Alternatives Considered	NPV Benefits/(Costs)
Option 2 consists of 19.8 km of NPS 12 steel TP pipe, 20.8 km of NPS 8 steel TP pipe, 14.9 km of NPS 6 steel pipe and associated valves and pig launchers/receivers.	$22,813,000
Option 3 consists of 19.8 km of NPS 12, 33.5 km of NPS 8, 6.6 km of NPS 6 TP steel pipe and associated valves and pig launchers/receivers	$23,533,000

Other Alternatives Considered	NPV Benefits/(Costs)
Option 4 consists of 45.0 km of NPS 12 TP and 14.9 km of NPS 6 steel pipe and associated valves and pig launchers/receivers.	$25,964,000
Option 5 – consists of building smaller capacity projects (looping) in response to specific customer or system needs. In addition, a large transmission project would still be necessary to meet the other operational requirements. The first four options evaluated all address the issues of providing capacity to Stonewall, providing operational flexibility, load shifting from Ile des Chenes and improving system reliability. The recommended Option 4 using the larger pipe sizes provides the greatest capacity increase which is required to meet our 20 year load growth projections, and provides the greatest available redundancy in order to minimize the risk of prolonged customer outages in the City of Winnipeg. The recommended option provides 25% additional redundant capacity to the Winnipeg HP system over Option 3, while being only an estimated 7% more expensive than Option 3, the second most expensive option.	$13,947,000 (for the identified smaller projects, additional $28, 034,000 to install the recommended option would be needed to meet all operational requirements)

Risk Analysis

The Manitoba Hydro six-step process to identify and manage risks was used to evaluate the recommended option. This analysis identified the consequence, likelihood and risk tolerance associated with the loss of gas supply from the Ile des Chenes pipeline and the limitations of the existing system identified; primarily the current lack of a redundant feed to the areas north of Winnipeg, no redundant transmission pressure supply to Winnipeg, the lack of operational flexibility for maintenance on the Ile des Chenes line. (For convenience, the definitions for the selected rating/descriptor are shown in brackets). The analysis indicated:

Likelihood: Unlikely (The event does occur somewhere from time to time, about every 30 years).
Consequence: High (High: Do not have capacity to serve load for extended period of time. Life threatening. Loss of public confidence).
Tolerance: Low (Additional action that is required to bring the risk back to the established tolerance. Management has time to respond in an orderly manner).

This risk analysis supports the requirement to perform the recommended system modifications. This project will partially address the gas capacity risks identified in the 2013 CS&D Risk Management Report.

The addition of capacity to the system in areas northwest of Winnipeg including St. Andrews, Stonewall and communities served by the Stonewall transmission branch (Warren, Stony Mountain, etc.) is required to permit the continued addition of customers and new load in this area. Two potential customers north of Stonewall had investigated obtaining natural gas service in 2013. While they have elected to investigate other options, the existing transmission system in this area would not have sufficient capacity to supply the proposed loads. The potential for gas outages in this area are only low if it is managed by restrictions or limitations on the addition of new load in this area. This is not acceptable to customers and, in the absence

Risk Analysis

of available natural gas, these customers may place additional load on the electrical system.

The long-term approach of reactive and piece-meal upgrades to provide capacity on an as-required customer-by-customer basis to suit the increase in loads in the individual areas does not meet Manitoba Hydro's reliability requirements. Typically capacity is achieved by looping existing pipelines (i.e, the installation of parallel pipelines). With looping solutions the transmission systems will continue to become more reliant on a single feed and will not have the flexibility in the case of a planned or unplanned outage. Predicted load growth in the next 5 to 10 years are estimated to require costs exceeding $21 million in looping projects alone.

The January 2014 natural gas outage caused by the TCPL line failure near Otterburne, Manitoba required approximately 48 hours to return the 3,600 affected customers to service once the TCPL supply was available. A large percentage of available, suitably skilled personnel were used in this response while the Manitoba Hydro costs associated with this outage were approximately $1.5 million. The outage also caused significant disruption and costs to the residential and commercial customers in the affected area. These costs have not been identified. Outages affecting larger numbers of customers may take significantly longer to return all customers to service while incurring greater costs.

The Otterburne gas outage illustrated the close relationship between the operation of the natural gas and electrical distribution systems. With the loss of the natural gas supply, customers turned to electrical heating to keep their homes and businesses warm and protect against freezing pipes. Significant efforts were made to shift electrical loads away from the stations in the affected area and monitor equipment operation. Fortunately, sufficient electrical capacity was available in this area. There are areas where the electrical distribution system is at capacity. In Winnipeg, 37 of 97 distribution stations supplying the City of Winnipeg are loaded beyond their firm rating and an additional 26 are loaded at 80 to 100% of their firm rating. In areas outside of Winnipeg, there are 276 distribution systems, with 19 loaded beyond their firm rating and an additional 27 at 80 to 100% of their firm rating. Electrical station upgrades are in progress but will take many years to complete. There is the potential for the loss of natural gas to result in cascading electrical system outages.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget	
Prev. Actuals	$	-
2014/15	$	256,886
2015/16	$	278,903
2016/17+	$	30,564,211
Total	$	31,100,000

Proposed Schedule	
Design Complete:	September 2015
Environmental and Third Party Approvals and Property Procurement:	December 2015
Construction Start:	May 2016
Construction Complete:	October 2016

Related Projects
Winnipeg Northwest Upgrade - Phase 1 – Liss Road - Project No: 2014-01001

Reference Documents
Report on: Winnipeg Northwest Upgrade - Phase 2; Study No. 2014-07031 GridEx II June 2014 (Emergency Response Exercise) Presentations excerpts Gas Planning Criteria Document (GPCD-2014) dated September 12, 2014

(IN THOUSANDS OF DOLLARS)

Title	Investment Management Node:
2014-07031 Winnipeg Northwest Upgrade	1.2.3.18.1.2
Owning Division: Distribution Eng & Construction Division — Coordinating Division: Distribution Eng & Construction Division	ProjectNumber: P:23593

DESCRIPTION:

The extension of an existing natural gas pipeline from the Rossar Station (GS-031) in Winnipeg to the City of Selkirk (GS-004) is necessary to provide additional capacity to the areas northwest of Winnipeg and to provide a redundant gas source to meet reliability and operational requirements in the Winnipeg natural gas transmission network. When compared to the alternatives, a single project combining the provision of additional capacity and redundancy is a financially efficient means of providing a reliable, resilient system suitable to meet the ongoing requirements and expectations of our customers.

JUSTIFICATION:

The rationale for completing this project are summarized as follows:
1. The requirement to correct high velocities in the Stonewall transmission branch and provide capacity in the area northwest of Winnipeg require modifications to the transmission system to provide new supply while maintaining system reliability. Combining these requirements while addressing other issues is an efficient means of improving the overall Winnipeg system.
2. To provide transmission capacity to serve the growth just north of Winnipeg for the next 20 years.
3. To provide the ability to shift load from the heavily-utilized pipeline on east side (Ile Des Chenes) of the City to the under-utilized pipeline on the west side of the City (Oak Bluff) and restore capacity in the City of Winnipeg system.
4. To provide full redundant supply to the communities north of Winnipeg and to provide a partial ability (approximately 1,000 m3/h) to back-feed the City of Winnipeg line in a loss of supply from either the Ile Des Chenes or Oak Bluff pipelines.
5. To improve operational flexibility to permit planned inspection, maintenance or construction activities.
6. The reactive approach where smaller projects are built in response to specific customer or system needs would result in approximately $21 million of projects that would be required in the next 5 to 10 years. While these projects would address capacity issues, they do not provide redundancy, or resolve any of the other issues identified. Meeting these other requirements would require an additional significant transmission investment which would be comparable in scope to the recommended course of action.
7. The June 20, 2014 PUB review of the Needs for and Alternatives to (NFAT) Review of Manitoba Hydro's Preferred Development Plan includes a recommendation that "Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating". The additional capacity provided by this project will readily support the addition of new customers in the area served.
The Winnipeg Northwest Upgrade project is Phase 2 of a project that is approved and will be constructed in 2014. The Phase 1 project addresses the local distribution issues in the St. Andrews area.

REFERENCE:

Report on: Winnipeg Northwest Upgrade - Phase 2; Study No. 2014-07031
GridEx II June 2014 (Emergency Response Exercise) Presentations excerpts
Gas Planning Criteria Document (GPCD-2014) dated September 12, 2014

REVISION:

New Item

IN SERVICE DATES

		Base estimate
2016/10/31	31100	2014/04/01 CLASS 2
		Work start date 2014/09/01

PREV. AUTHORITY	GROSS	ESCALATION	INT. CAPITALIZED	SALVAGE	CONTRIBUTION	TOTAL NET COST
Actual cost to date: (Over/under expend:						
V-HAP TOTAL						
REV. AMOUNTS: Actual cost to date: (Over/under expend:						
Auth: 2014/15	250	3	4			257
Req: 2015/16	250	7	22			279
2016/17	26800	1256	4697			30564
VHLO TOTAL	29300	1306	4695			[illegible]

Prepared by	yy mm dd	Approved by OWNING DIVISION	yy mm dd	Approved by COORDINATING DIVISION	yy mm dd	Approved by	yy mm dd
WJ9	14/10/08		14/10/14		14/10/14		14/12/17

2014/10/08 08:39AM

MB

CE8(1) Rev. 07 12

CAPITAL EXPENDITURE REVISION

FORECAST HISTORY (in thousands of dollars)

Project Number: P:23593

Approved yy mm	TOTAL AMOUNT	COMMENTS

Forecasted Mthly Exp.	GROSS	ESCALATION	INTEREST CAP.	CONTRIBUTION	SALVAGE	TOTAL NET COST	YTD Accumulated
2014/15 Apr							
May							
Jun							
Jul							
Aug							
Sept	35					35	35
Oct	39					39	74
Nov	33					33	107
Dec	35		1			36	143
Jan	37	1	1			39	182
Feb	33	1	1			35	217
Mar	38	1	1			40	257
TOTAL	250	3	4			257	257
2015/16 Apr	19		1			20	20
May	20		1			21	41
Jun	23	1	1			25	66
Jul	23	1	2			26	92
Aug	20	1	2			23	115
Sep	20	1	2			23	138
Oct	22	1	2			25	163
Nov	20	1	2			23	186
Dec	20	1	2			23	209
Jan	20	1	2			23	232
Feb	19	[illegible]	2			22	254
Mar	[illegible]	2	3			25	279
TOTAL	260	7	22			279	279

ROUTING SLIP FOR APPROVAL OF A

CPJ or CPJ ADDENDUM for a MAJOR item

FINANCE CONTACT: Isaacson, Marie (360-7787)

DATE: October 7, 2014

COMPLEX NAME: Winnipeg Northwest Upgrade - Phase 2

RECEIVED
DEC 10 2014
Customer Service & Distribution

COMPLEX / I.M. NODE NUMBER: ~~1.2.3.25.8.2~~ 1.2.3.10.1.2

WBS NUMBERS: P:23593

OWNING DIVISION FOR COMPLEX: Distribution Engineering & Construction Wpg

COORDINATING DIVISION FOR COMPLEX: Distribution Engineering & Construction Wpg

INSTRUCTIONS:

1) Review attached CPJ and associated CERs belonging to this complex.

<u>If you wish to request changes:</u>

2a) Circle YES under the CHANGES REQUIRED column next to your name and enter a description of the change(s) in the space provided below.

2b) Return the package immediately to the person listed next to the red "Return package to:" below.

<u>If you wish to indicate your approval of the entire Complex:</u>

2a) Circle NO under the CHANGES REQUIRED column, sign in the SIGNATURE box next to your name, and follow the additional instructions, if applicable.

2b) Check to see if your name appears on this routing slip a second time and if so, sign in both locations.

2c) Forward the package to the next person on the list.

	CHANGES REQUIRED?	SIGNATURE	ADDITIONAL INSTRUCTIONS	
Complex Coordinator: 1 Blazek, Greg	YES / NO	Greg Blazek	*CPJ:* not applicable	*CERs:* INITIAL the Coord. Div. box
Complex Coord. Sup/Section Head: 2 not applicable	YES / NO		*CPJ:* INITIAL & DATE the title page, next to Noted by:	*CERs:* not applicable
Dept Manager - Coordinating: 3 Starodub, Tim	YES / NO	Tim Starodub	*CPJ:* SIGN & DATE the title page, next to Noted by:	*CERs:* SIGN & DATE the Coord. Div. box
Complex Owner: 4 Starodub, Tim	YES / NO	Tim Starodub	*CPJ:* INITIAL & DATE the title page, next to your name	*CERs:* INITIAL the Owning Div. box
Complex Owner Sup/Section Head: 5 Aftanas, Alan	YES / NO	A. Aftanas	*CPJ:* SIGN & DATE the title page, next to Reviewed by:	*CERs:* not applicable
Dept Manager - Owning: 6 Starodub, Tim	YES / NO	Tim Starodub	*CPJ:* SIGN & DATE the title page as Owning Dept. Mgr	*CERs:* SIGN & DATE the Owning Div. box
Division Manager - Owning: 7 Steele, Chuck	YES / NO	Chuck Steele	*CPJ:* SIGN & DATE the title page as Owning Div. Mgr	*CERs:* not applicable
Division Manager - Budget Support: 8 Prydun, Mark	YES / NO	Mark Prydun	*CPJ:* SIGN the CPJ in the financial Department signature b[ox]	*CERs:* not applicable
Vice President 9 Read, Brent	YES / NO	Brent Read	*CPJ:* SIGN & DATE the title page as Business Unit VP	*CERs:* SIGN & DATE the Vice President box

Return package to: Isaacson, Marie (360-7787)

CHANGES REQUIRED: ☐ see mark-up on CPJ / CER(s)

continue on reverse if necessary

These documents are time-sensitive. Your earliest attention would be appreciated.

REFERENCE:

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

PREAMBLE TO IR (IF ANY):

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

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

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

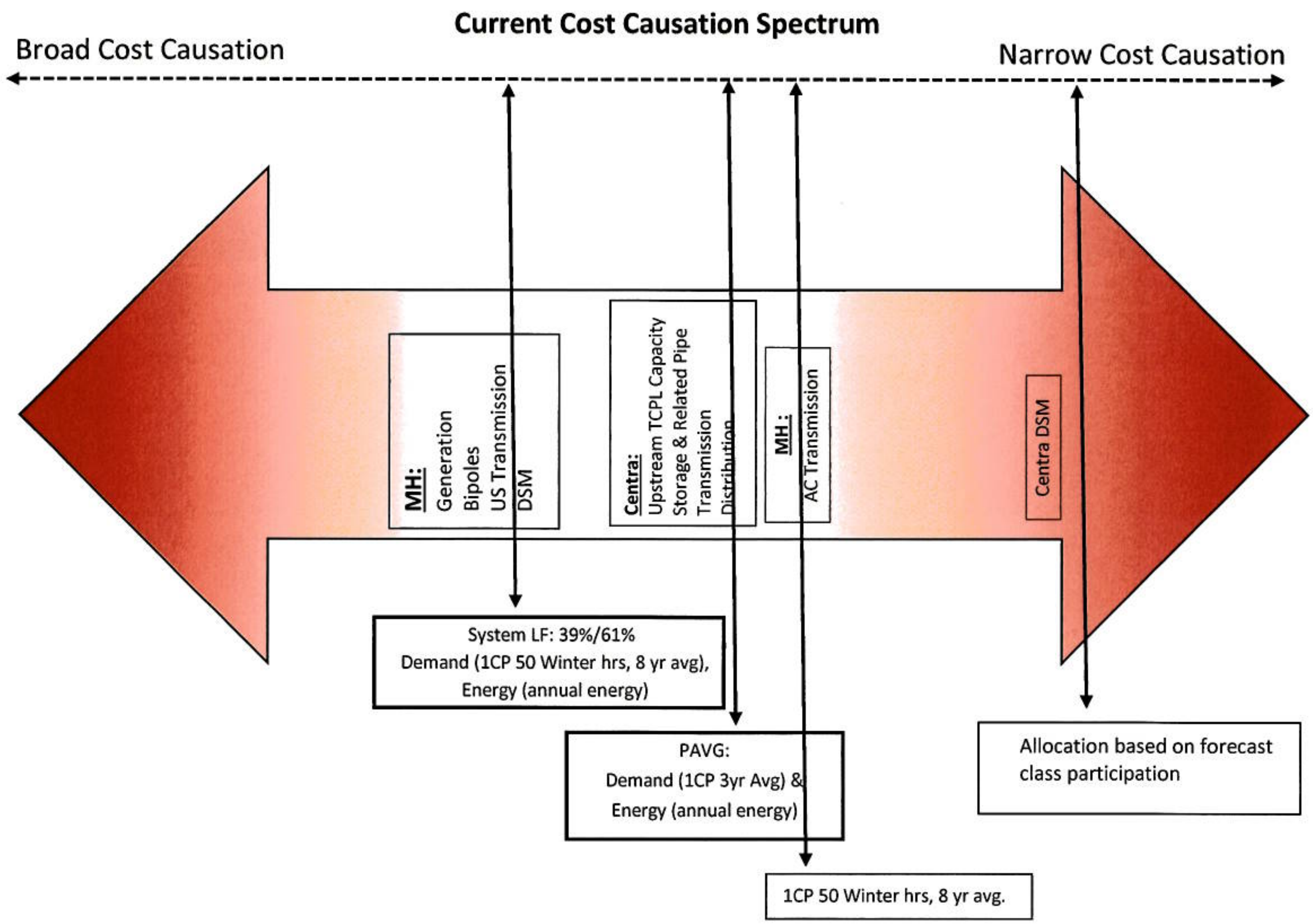
QUESTION:

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

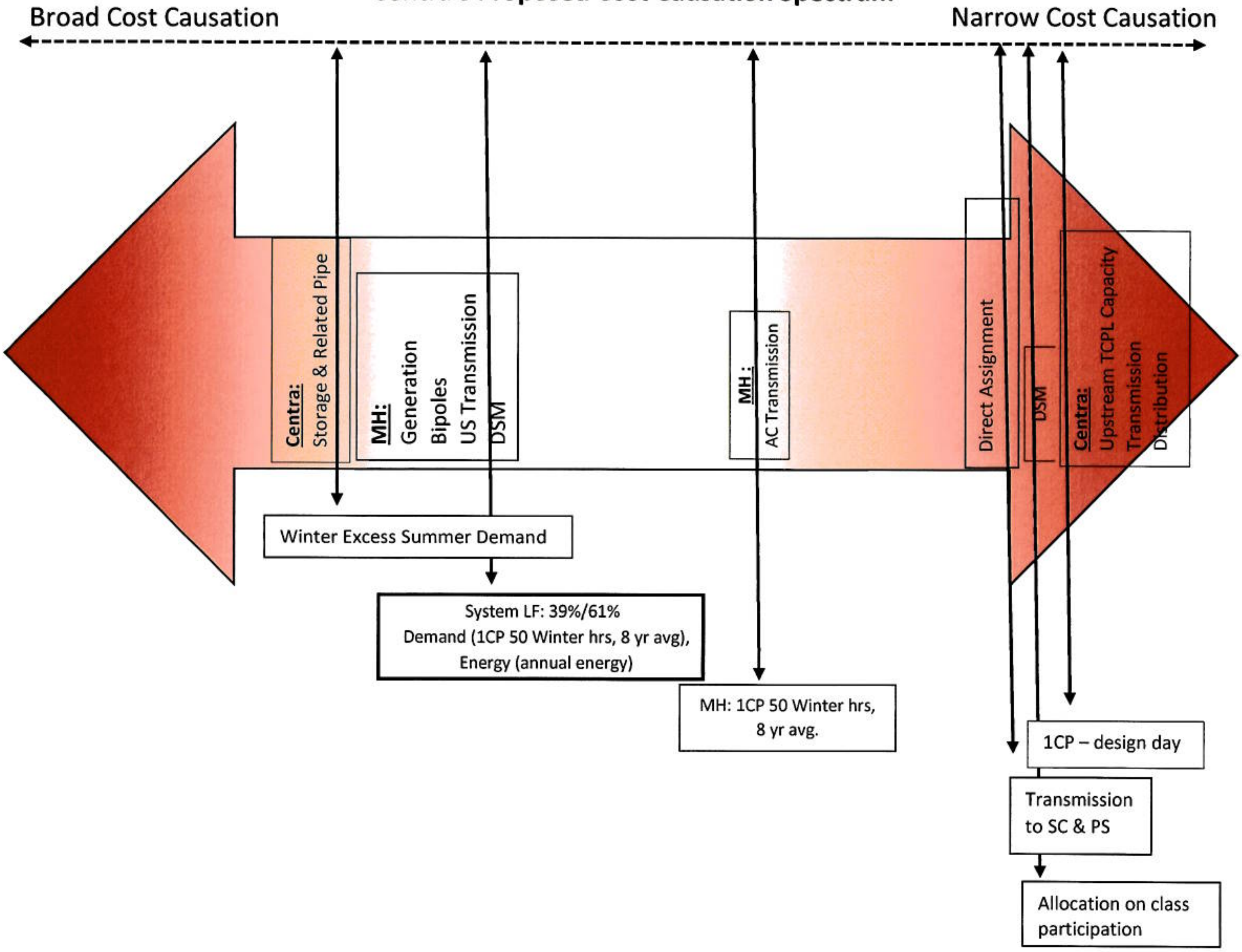
RESPONSE:

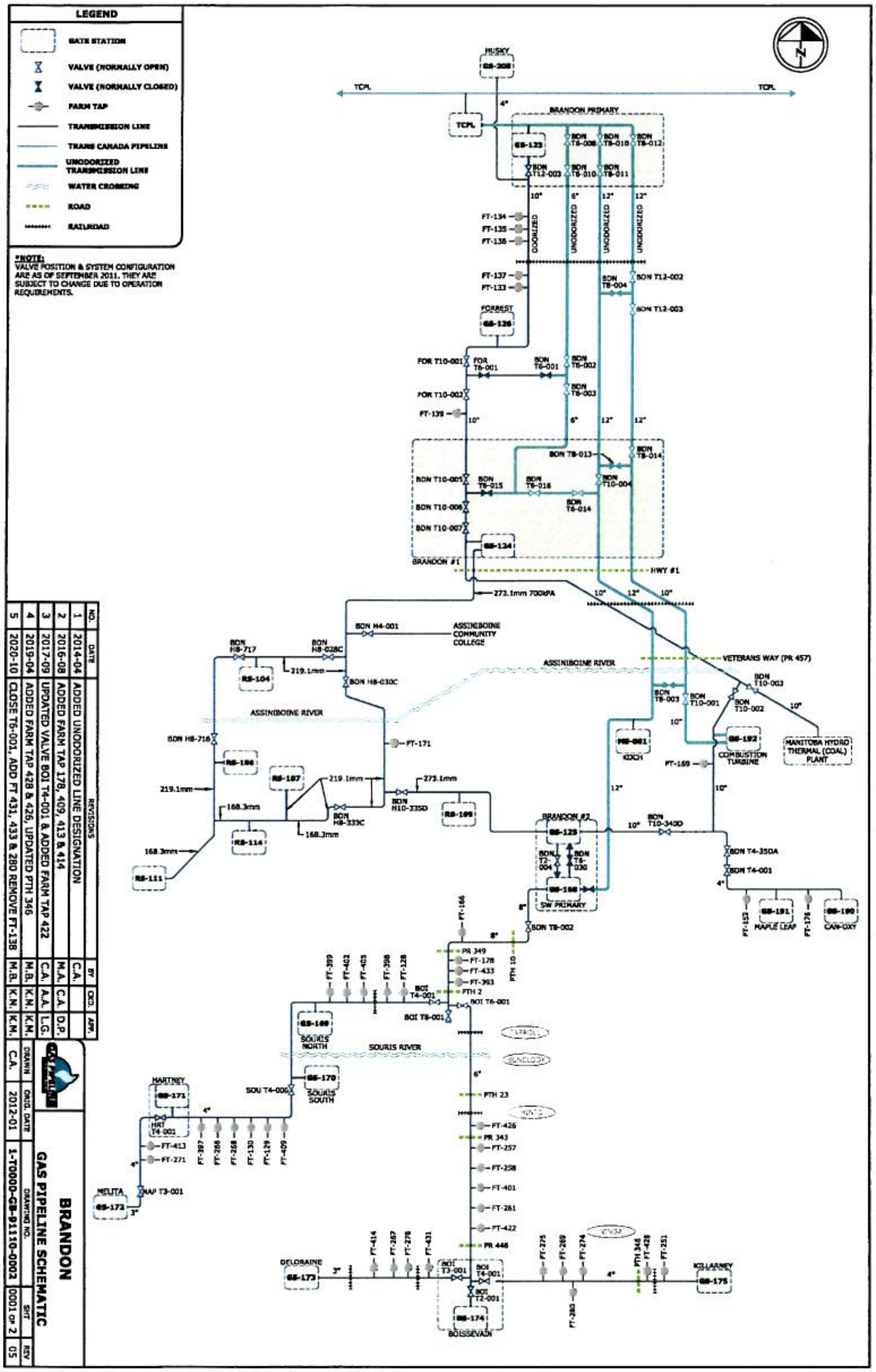
Centra adopted the Peak and Average allocator after its 1996 Cost of Service Methodology Review. At the time of adoption the following factors were identified as influencing Centra's position: Peak and Average recognized the utilization of the system as an explicit factor to be included in determining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

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


Current Cost Causation Spectrum
Broad Cost Causation
Narrow Cost Causation
MH:
Generation
Bipoles
US Transmission
DSM
Centra:
Upstream TCPL Capacity
Storage & Related Pipe
Transmission
Distribution
MH:
AC Transmission
Centra DSM
System LF: 39%/61%
Demand (1CP 50 Winter hrs, 8 yr avg),
Energy (annual energy)
PAVG:
Demand (1CP 3yr Avg) &
Energy (annual energy)
1CP 50 Winter hrs, 8 yr avg.
Allocation based on forecast
class participation

Centra's Proposed Cost Causation Spectrum




LEGEND
GATE STATION
VALVE (NORMALLY OPEN)
VALVE (NORMALLY CLOSED)
FARM TAP
TRANSMISSION LINE
TRANS CANADA PIPELINE
UNODORIZED TRANSMISSION LINE
WATER CROSSING
ROAD
RAILROAD
*NOTE:
VALVE POSITION & SYSTEM CONFIGURATION ARE AS OF SEPTEMBER 2011. THEY ARE SUBJECT TO CHANGE DUE TO OPERATION REQUIREMENTS.
TCPL
HUSKY
GS-208
BRANDON PRIMARY
GS-123
FORREST
GS-126
BRANDON #1
GS-124
HWY #1
273.1mm 700kPA
ASSINIBOINE COMMUNITY COLLEGE
ASSINIBOINE RIVER
VETERANS WAY (PR 457)
MANITOBA HYDRO THERMAL (COAL) PLANT
COMBUSTION TURBINE
GS-192
KOCH
BRANDON #2
GS-125
SW PRIMARY
GS-169
MAPLE LEAF
GS-191
CAN-OXY
GS-190
RS-104
RS-106
RS-107
RS-114
RS-111
RS-105
SOURIS NORTH
GS-169
SOURIS RIVER
SOURIS SOUTH
GS-170
HARTNEY
GS-171
MELITA
GS-172
DELORAINE
GS-173
BOISSEVAIN
GS-174
KILLARNEY
GS-175
NO. | DATE | REVISIONS | BY | CKD. | APP.
1 | 2014-04 | ADDED UNODORIZED LINE DESIGNATION | C.A. | |
2 | 2016-08 | ADDED FARM TAP 178, 409, 413 & 414 | M.A. | C.A. | D.P.
3 | 2017-09 | UPDATED VALVE BOI T4-001 & ADDED FARM TAP 422 | C.A. | A.A. | L.G.
4 | 2019-04 | ADDED FARM TAP 428 & 426, UPDATED PTH 346 | M.B. | K.M. | K.M.
5 | 2020-10 | CLOSE T6-001, ADD FT 431, 433 & 280 REMOVE FT-138 | M.B. | K.N. | K.M.
BRANDON
GAS PIPELINE SCHEMATIC
DRAWN C.A.
ORIG. DATE 2012-01
DRAWING NO. 1-T0000-GB-91110-0002
SHT 0001 OF 2
REV 05

While this has not always been the case, Centra's system configuration has evolved and based on conditions assumed in the Cost of Service Study (i.e. normal operating conditions), Centra is able to identify facilities that are used to serve the Special Contract Class exclusively and do not serve load for any other customers.

Additionally, the pipelines that serve this customer class predominantly have a one-way relationship with the rest of the system. This is to say that the remainder of the transmission system can receive pressure and capacity support from the pipelines that serve the Special Contract Class, but the rest of the Brandon system, with the exception of the facilities serving the Brandon Power Station, cannot generally be used to serve the load requirements of the Special Contract Class.

Similarly, the facilities that serve the Power Station in Brandon do not serve any other customers under normal operating conditions. Furthermore, given both the customers' inability to utilize other parts of Centra's system from an operating perspective (i.e. the requirement for unodourized gas and high-pressure requirements), Centra supports Atrium's recommendation for a Direct Assignment approach for the Special Contract Class and the Brandon Power Station.

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

Overall, a Direct Assignment is a reasonable approach in the current circumstances and will provide a stable allocation of costs for both the Special Contract and Power Station Classes.