BAILEY & DIXON

Christina D. Cress
Of Counsel
ccress@bdixon.com

September 23, 2021

VIA Electronic Filing

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. G-5, Sub 632
Evergreen Packaging, LLC, Direct Testimony and Exhibits of Brian C. Collins

Dear Ms. Dunston:

On June 11, 2021, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, setting the date for the filing of direct testimony and exhibits of intervenors and the Public Staff in this docket to be on or before September 17, 2021.

On September 16, 2021, the Commission issued its Order Granting Extension of Time to File Direct and Rebuttal Testimony, extending the time for intervenor and Public Staff filing of direct testimony and exhibits to be filed in this docket on or before September 23, 2021.

Pursuant to these Orders, we hereby submit the direct testimony and exhibits of Brian C. Collins on behalf of Evergreen Packaging, LLC.

Fourteen paper copies of this filing will be delivered to the Chief Clerk's Office by close of business on September 24, 2021, as required by ordering paragraph 13 of the Commission's June 11, 2021, Order.

We are electronically forwarding copies of this filing to all parties of record.

Sincerely,

Electronically submitted
/s/ Christina Cress, Counsel of Record
Evergreen Packaging, LLC

CDC:kac

Enclosures

cc: Parties of Record

STATE OF NORTH CAROLINA

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of **Application of Public Service Company of North Carolina, Inc. for a General Increase in Rates and Charges**	)	**DOCKET NO. G-5, SUB 632**

Direct Testimony and Exhibits of

Brian C. Collins

On behalf of

Evergreen Packaging, LLC, a subsidiary of Pactiv Evergreen, Inc.

September 23, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11167

STATE OF NORTH CAROLINA

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of **Application of Public Service Company of North Carolina, Inc. for a General Increase in Rates and Charges**	)	**DOCKET NO. G-5, SUB 632**

Direct Testimony of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a principal with Brubaker & Associates, Inc., a firm specializing in energy, economic and regulatory consulting. Our firm and its predecessor firms have consulted in this field since 1937 and have participated in more than 1,000 proceedings in 40 states and several Canadian provinces. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies ("LDCs").

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of Evergreen Packaging, LLC, a subsidiary of Pactiv Evergreen, Inc. ("Evergreen"). Evergreen is a major contributor to the economy for this service territory in North Carolina and the large increase as proposed by Public Service Company of North Carolina, Inc. ("PSNC") is inappropriate and unwarranted.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION" OR "NCUC")?

A No. However, I have been involved in many gas and electric proceedings in other jurisdictions over the last 20 years and have presented testimony in many of those proceedings.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony is directed toward PSNC's gas cost of service study, the allocation of any allowed rate increase to customer classes, and rate design. I have examined the testimony and exhibits presented by PSNC in this (and its last general rate case) proceeding with respect to cost of service, revenue allocation, and rate design, and I will comment on the propriety of these proposals, and make certain comments and recommendations. In addition, I comment on the federal and state tax credits due to PSNC customers. I also address PSNC's proposed return on equity ("ROE") and make recommendations in this regard.

Q DOES THE FACT THAT YOU DO NOT ADDRESS EVERY ISSUE RAISED IN PSNC'S TESTIMONY MEAN THAT YOU AGREE WITH PSNC'S TESTIMONY ON THOSE ISSUES?

A No. It merely reflects that I did not choose to address all of those issues. It should not be read as an endorsement of, or an agreement with, PSNC's position on such issues. In order to make my presentation consistent with the revenue levels requested by PSNC, I have used the revenues produced by PSNC's proposed rates. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of any rate increase authorized for PSNC.

Summary of Conclusions and Recommendations

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING.

A The summary of my conclusions and recommendations is listed below:

1. PSNC's gas rates should be based on the cost of providing service to each customer class. They are not.

2. PSNC's gas cost of service study is a form of an arbitrary peak and average method and allocates excessive cost to high load factor customers on a throughput weighted allocation as compared to a peak demand cost of service study. PSNC's proposed 50% throughput / 50% design day peak cost of service study is unsupported by engineering studies and inconsistent with the design of the PSNC gas delivery system.

3. PSNC's gas delivery system is designed to meet design day peak demand.

4. PSNC has provided a design day peak cost of service study, which is reflective of cost causation and should be used as the basis for revenue distribution and rate design.

5. Mr. John D. Taylor, managing partner of Atrium Economics, presents the cost of service for PSNC. Atrium Economics recently issued a 2021 cost of service review for Centra Gas Manitoba Inc., in which it soundly rejects the peak and average method previously used by the utility and recommends the design day peak method as reflective of cost causation for a local distribution company.

6. PSNC proposes a distribution of the increase based on a 20% rate of return band receiving an average increase, with 50% of the average increase allocated to classes above the 20% band, and 200% of the average increase allocated to classes below the 20% band. This method is overly harsh, unreasonable, and unjust to classes below the 20% band. No class should receive an increase more than a maximum 150% of the average increase as an upper limit.

7. The results of the design day peak study, which should be used as the basis for rate design, show that most classes are close to cost of service with no class receiving the harsh increase currently proposed by PSNC.

8. PSNC's proposed rate design for Rate 175 should be rejected. It is not cost based, not reflective of any cost study for the various rate blocks and significantly punishes high usage customers.

9. Rather, Rate 175 should be refined to:

   a. Contain a basic facilities charge reflective of cost;

   b. Collect fixed charges in the initial blocks; and

   c. Decrease charges in higher usage blocks to be reflective of only variable costs.

10. PSNC has requested an excessive return on equity of 10.25%. Based on a review of capital cost reductions that have occurred since PSNC's last general rate case, it is recommended that the allowed ROE not exceed 9.55% in this proceeding.

Cost of Service and Rate Design Principles

Q COULD YOU PLEASE EXPLAIN THE RATEMAKING PROCESS AND THE DESIGN OF RATES?

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how any alterations in the utility's costs and/or revenues should be distributed among the major customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within that class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current

rate levels exceed the utility's revenue requirement, a rate reduction is required. In short, overall rate revenues should equal actual cost of service. The same principle should apply in the next two steps. Each major customer class should produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for making this determination is a class cost of service study which shows the rates of return for each class of service. Rate levels should be modified so that each major class of service provides approximately the same rate of return. Finally, in designing individual tariffs, the goal should also be to relate the rate design of each class to the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing service to that customer.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATEMAKING PROCESS?

A The basic reasons for using cost of service as the primary factor in the ratemaking process are equity and stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A When rates are based on cost, each customer (to the extent practicable) pays what it costs the utility to serve that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility associated with changes in customer usage patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for future rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of costs and also provide more accurate price signals. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within each class). With respect to rates based on factors other than costs, from the industrial customer's perspective, this situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan or predict future levels of costs or effectively respond to price signals.

Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?

A I am referring to the utility's "embedded" or actual accounting costs of rendering service; that is, those costs which are used by the Commission in establishing the utility's overall revenue requirement.

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COST OF SERVICE STUDY?

A After determining the overall cost of service or revenue requirement, a cost of service study is used to allocate the cost of service among customer classes. A cost of service

study shows how each major customer class contributes to the total system cost. For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues just sufficient to cover the costs incurred in serving it (including a reasonable return on investment). If a class produces a below-average rate of return, then the revenues are insufficient to cover all relevant costs. On the other hand, if a major class produces an above-average rate of return, it is paying revenues beyond sufficient to cover the cost attributable to it. In addition, it is subsidizing part of the cost attributable to other classes which produce a below-average rate of return. The class cost of service study is important because it demonstrates the various class revenue requirements, as well as the rates of return under current and proposed rates.

Q WOULD YOU PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A COST OF SERVICE STUDY?

A Yes. Cost of service is a basic and fundamental ingredient to proper ratemaking. In all class cost of service studies, certain fundamental concepts must be recognized. Of primary importance among these concepts is the functionalization, classification, and allocation of costs. Functionalization is the determination and arrangement of costs according to major functions, such as transmission, distribution and storage of gas. Classification involves identifying the nature of these costs as to whether they vary with the quantity of gas consumed, the demand placed upon the system, or the number of customers being served.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in gas deliveries and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the

investment in utility facilities and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are basically those costs which tend to vary with throughput and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of gas consumed or the demands placed upon the system. A correct application of these concepts is essential to the proper development of a cost of service study, as well as the appropriate rate design within each customer class.

With respect to allocation, fixed costs should be allocated on a peak demand factor, variable costs should be allocated on a throughput factor, and customer-related costs should be allocated on a per customer allocation factor.

PSNC's Gas Cost of Service Study

Q HAVE YOU REVIEWED THE GAS COST OF SERVICE STUDIES PERFORMED BY PSNC IN THIS PROCEEDING?

A Yes. PSNC witness John D. Taylor submitted 2020 cost of service studies based on present rate-adjusted results and under PSNC's proposed rates. I will focus on the present rates adjusted for test year study.

Q DO YOU AGREE WITH THE ALLOCATION METHODS UTILIZED BY PSNC IN ITS TEST YEAR 2020 GAS COST OF SERVICE STUDY?

A With the exception of the peak and average allocation method which allocates more cost to high load factor customers, I mostly agree with the PSNC cost of service study. However, the 50% throughput weighting in the peak and average allocator is unsupported, arbitrary, and inconsistent with system design. The peak day demand method is more reflective of cost causation and system design.

PSNC states that its system is designed to meet all firm customer demands under design day conditions. The allocation of costs should follow system design to reflect cost-causation. Average demand (throughput) is not relevant and the 50% weighting is unsupported by study or fact.

Q HAS MR. TAYLOR'S FIRM RECENTLY ISSUED A REPORT REJECTING THE USE OF THE PEAK AND AVERAGE METHOD FOR ALLOCATING THE COST OF MAINS TO CUSTOMER CLASSES?

A Yes. Mr. Taylor, managing partner of Atrium Economics, presents the cost of service for PSNC based on the peak and average method. However, his firm, Atrium Economics, recently issued a 2021 cost of service review for Centra Gas Manitoba Inc., which soundly rejects the peak and average method previously used by the utility and recommends the design day peak method as reflective of cost causation for a local distribution company.

Q WHAT DOES THE ATRIUM REPORT RECOMMEND?

A The Atrium report, which is attached as Exhibit BCC-6, recommends that the peak and average method is not consistent with cost causation and penalizes high load factor customers and should be replaced with a design day peak method. The Atrium report states:

> "*Replace Allocation of Transmission and Distribution Plant Using the Peak & Average Allocation Method with a Coincident Peak Day Allocation Method.* Atrium maintains that transmission and distribution plant is a function of the cumulative peak day demands of those customers served by those pipeline infrastructure investments and recommends the use of a Coincident Peak Day allocation of transmission mains and the demand component of distribution mains."

* * *

"The P&A method penalizes high load factor customer classes in the following manner. Economies of scale are always recognized when a gas utility sizes its distribution mains to satisfy peak capacity requirements of its customers. The concept of economies of scale drives overall costs incurred by a gas utility for its gas distribution mains and these economies of scale are reflected in Centra's embedded costs of distribution mains. However, economies of scale affect the sizing of distribution mains- but not the allocation of their resulting costs. The economies of scale enjoyed by a gas utility are created by the interaction of the capacity requirements of all its customers. Centra does not plan for the changing needs of its distribution system by examining the capacity requirements of any one customer class or by conducting capacity planning by first disaggregating its capacity needs into "average demand requirements" and "peak demand requirements." Rather, it examines its capacity needs in the aggregate based on the peak hour demands on its design day for all of its customers or for the group of customers added to the existing distribution system at any point in time.

The fallacy in the P&A allocation method becomes clear for a customer class that exhibits a high load factor. According to the P&A allocation method, this class should not receive any economies of scale benefits because the class' average demand is high relative to its peak demand. Yet, the engineering reality is that this class should receive economies of scale benefits just as any other class to the extent the capacity requirements of this class at the time these customers were connected to the gas utility's distribution grid created economies of scale in the costs of expanding the grid to accommodate them.

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

* * *

"A Local Distribution Company's (LDC's) gas system is designed, and consequently capacity related costs are incurred, to meet design day demand. In contrast, these costs are not incurred on the basis of an average of peak demands."

Q DO YOU AGREE WITH THE ATRIUM REPORT REGARDING THE REJECTION OF THE PEAK AND AVERAGE COST ALLOCATION METHOD AND THE RECOMMENDATION TO USE THE DESIGN DAY PEAK METHOD?

A Yes. The Atrium report is correct in that regard.

Q WHAT IS THE BASIS FOR PSNC'S SYSTEM DESIGN?

A PSNC states:

> "PSNC's system is designed to serve firm customers on a design day while maintaining target minimum pressures within the system (typically 30 PSIG in a 60 PSIG system)."
>
> (PSNC's response to Evergreen's Data Request No. 2, August 6, 2021, Response 2-3)

Q IS THE ALLOCATION OF FIXED DELIVERY COSTS BASED ON DESIGN DAY DEMAND DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS ("NARUC") GAS DISTRIBUTION RATE DESIGN MANUAL?

A Yes. NARUC recognizes that distribution mains should be allocated to customer classes based on: (1) design peak day demands for the demand component; and (2) the number of customers for the customer component. In that regard, the NARUC Gas Distribution Rate Design Manual states the following:

> Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers **or their annual usage**. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size. (NARUC Manual, Gas Distribution Rate Design, June 1989, pp. 23-24; emphasis added)

Q ARE YOU AWARE OF ANY OTHER AUTHORITATIVE AGENCY'S POSITION ON THE CLASSIFICATION AND ALLOCATION OF GAS DISTRIBUTION MAIN COSTS?

A Yes. In Order 636, the Federal Energy Regulatory Commission ("FERC") endorsed the straight fixed-cost variable ("SFV") cost methodology, which allocates fixed pipeline cost 100% on a demand basis. In this regard, FERC states:

> The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equality principle.
>
> ********
>
> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant natural gas over alternate fuels such as foreign oil. SFV is the best method for doing that. (FERC Order 636, Final Rule Issued April 8, 1992, pp. 127-129 [Footnote omitted.])

The FERC SFV allocation method appropriately treats fixed pipeline costs as demand-related costs. Similarly, transmission and distribution main costs not classified as customer-related on PSNC's system should be treated as demand-related costs to achieve the goals and benefits outlined by the FERC and which comport with NARUC guidance.

Q TO YOUR KNOWLEDGE, HAVE ELECTRIC UTILITIES USED THE PEAK AND AVERAGE METHOD TO ALLOCATE TRANSMISSION OR DISTRIBUTION COSTS IN NORTH CAROLINA?

A No. To my knowledge, the peak and average method has not been used to allocate transmission or distribution costs in North Carolina. I am not aware that it has ever

been proposed. The peak and average method should not be used to allocate the delivery costs for gas.

Q HAS PSNC PERFORMED A STUDY USING THE PEAK DEMAND TO ALLOCATE FIXED COSTS TO CLASSES?

A Yes. PSNC performed a peak demand study in response to discovery from Evergreen. In that study, peak demand data is used to allocate fixed demand-related delivery costs in place of the peak and average method. The results of the peak demand study are shown on Exhibit BCC-1.

The peak demand study is a more correct representation of the actual cost of service associated with serving the various customer classes and should be used as the basis for the allocation of any allowed increase in this proceeding. The peak demand shows that certain subsidies are larger and make any corrective distribution of the requested increase even more difficult to manage in this case.

Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN, INDEXES AND SUBSIDIES BASED ON THE DESIGN DAY PEAK COST OF SERVICE?

A Yes. Exhibit BCC-1 shows the results of the design day cost of service, and also indexes and subsidies at both current rates and rates based on the recommended distribution of the increase Residential, Small General Service and Large Quantity Interruptible Service classes are close to cost of service. The Medium General and Large Quantity General service classes are significantly above cost of service.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED DISTRIBUTION OF THE INCREASE?

A I basically used the parameters recommended by PSNC. Classes close to cost of service received an approximate average increase; classes above cost of service receive approximately 50% of the average increase. Exhibit BCC-2 shows the recommended distribution of the increase based on total revenue and Exhibit BCC-3 shows the recommended distribution of the increase based on margin or distribution revenue.

Q HAVE YOU REVIEWED PSNC'S PROPOSED RATE DESIGN FOR RATE 175?

A Yes. PSNC's proposed rate design is shown on Exhibit BCC-4. PSNC is proposing significant increases to the higher usage blocks, which is inappropriate and would result in harsh, unreasonable, and unwarranted impacts or rate shock to higher usage customers. A declining block rate structure should be designed to collect fixed costs in the initial usage blocks and, once fixed costs are recovered, the higher usage blocks should only be recovering variable costs. To the extent the Commission approves a lower increase than the $53 million requested, I recommend that the higher usage blocks be lowered to reflect only variable costs.

Q HAS PSNC PERFORMED ANY COST STUDIES REGARDING THE SIZE OR ADEQUACY OF THE RATE BLOCKS IN RATE 175 ON THE CHARGES FOR THE VARIOUS RATE BLOCKS?

A No. In response to Evergreen's Data Request No. 1, PSNC stated the following:

> "The proposal presented in this case is for no changes to the basic facility charge and for the proposed revenue increase to be recovered through an equal volumetric increase to all volumetric blocks rates. Please see the Direct Testimony of John D. Taylor at page 24. This proposal required no analysis or separate study regarding the charges by usage block, for summer and winter periods, or for sales and transportation rates."

(PSNC's Response to Evergreen's DR 01-24; July 19, 2021).

Q IS THE DESIGN OF RATE 175 AN IMPACT ISSUE FROM PSNC'S MOST RECENT RATE CASE?

A Yes. Rate Design in Docket No. G-5, Sub 565 was an impact issue and addressed in the stipulation as follows:

> "The rate schedules and steps have not changed since the last rate case in 2016. In that case (Docket No. G-5 Sub 565), the Commission approved the rate design agreed to in Paragraph 5.E., which provided:
>
> > Rate Design. The Stipulating Parties are still continuing to work on rate design issues since the revenue requirement increase has not yet been determined. Notwithstanding the pending determination of the revenue requirement, the Stipulating Parties agree in principle that after a determination of the revenue requirement, each energy charge for Rate Schedule 145 and Rate Schedule 150 will be increased by no more than 3.25% and each existing energy charge for Rate Schedule 175 and Rate Schedule 180 will be increased by no more than 2.25%. The Stipulating Parties have agreed to an additional usage tier for Rate Schedule 175, as shown on Public Staff witness Jan Larsen's Amended Exhibit C, page 2 of 2. The Stipulating Parties agree that this additional usage tier will not result in any revenue shifting between any rate classes."

Q HAVE YOU DEVELOPED A RECOMMENDED RATE STRUCTURE FOR RATE 175?

A Yes. This is shown on Exhibit BCC-5. I have used an across-the-board approach to increase the rate blocks by approximately 9.9%. The recommended rate design is fair and reasonable to the customers taking service from Rate 175.

Since PSNC's large usage rates do not contain demand charges, the initial blocks should provide for fixed cost recovery in a similar manner to a demand charge that would provide for fixed cost recovery. The higher usage blocks should have relatively lower charges to reflect variable delivery costs similar to an energy charge for a tariff which contains a demand charge. Of course, the BFC should recover customer costs.

My recommended rate design, as shown in Exhibit BCC-5, follows this cost-based approach.

Return on Equity

Q IS PSNC'S PROPOSED 10.25% ROE REQUEST APPROPRIATE?

A No. PSNC's requested ROE of 10.25% is excessive and should be rejected. The Company's current authorized ROE is 9.70%, which was authorized by approving a stipulation in the Commission's Final Order in Docket No. G-5, Sub 565, issued on October 28, 2016.

Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its *Major Rate Case Decisions* report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized ROEs resulting from utility rate cases around the country. The most recent report has been updated through June 30, 2021 and shows that the national average authorized ROE for gas utilities for the 12 months ending June 30, 2021 was 9.55%. This is 15 basis points below PSNC's currently authorized ROE. The Commission also should consider the IMR, and any other mechanisms which provide PSNC with additional cost recovery outside of a base rate case in setting a reasonable ROE.

On that basis, the Company's current ROE, and definitely its requested ROE, are significantly above a reasonable cost of equity. I recommend that the Commission authorize a ROE that does not exceed the national average of 9.55%.

Excess Deferred Income Taxes

Q DO YOU HAVE ANY COMMENTS ON THE COMPANY'S PROPOSAL TO FLOW THROUGH THE BENEFITS OF THE FEDERAL TAX CUTS AND JOBS ACT OF 2017

("TCJA") TO CUSTOMERS AS DESCRIBED IN PSNC WITNESS JAMES A. SPAULDING'S DIRECT TESTIMONY?

A Yes. The Excess Deferred Income Taxes ("EDIT") should be returned to customers as quickly as possible. The EDIT should also appropriately be returned to customers in the same manner that customers paid the taxes to PSNC. This will result in an appropriate allocation of EDIT to customers.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's

allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Guam Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

421377

Public Service Company of North Carolina, Inc.

Docket No. G-5, Sub 632

Class Cost of Service Study Results
at Present and Proposed Rates
using Design Day
Test Year Ended December 31, 2020

			Present Rates			Proposed Rates		
Line	Customer Class	Rate	Rate of Return	Relative Rate of Return	Subsidy (000)	Rate of Return	Relative Rate of Return	Subsidy (000)
			(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	101, 102, 115	4.87%	0.92	$ (7,201)	7.22%	0.95	$ (6,760)
2	Small General Service	125, 126, 127	5.65%	1.06	$ 1,193	8.67%	1.13	$ 3,724
3	Medium General Service	140	10.36%	1.95	$ 3,117	12.05%	1.58	$ 2,737
4	Large Quantity General Svc	145, 175	6.97%	1.31	$ 3,005	8.03%	1.05	$ 712
5	Large Quantity Interruptible Svc	150, 180	5.14%	0.97	$ (115)	7.00%	0.92	$ (413)
6	Total		5.32%	1.00	$ -	7.64%	1.00	$ (0)

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Allocation of Proposed Revenue
using PSNC's Proposed Allocation of Increase
and Design Day
Test Year Ended December 31, 2020
(Dollars in Thousands)

Line	Customer Class	Rate	Current Total Revenue (1)	Proposed Revenue Increase (2)	Proposed Total Revenue (3)	% Increase (4)
1	Residential	101, 102, 115	$ 359,911	$ 37,743	$ 397,655	10.5%
2	Small General Service	125, 126, 127	$ 103,195	$ 10,822	$ 114,017	10.5%
3	Medium General Service	140	$ 22,279	$ 1,168	$ 23,448	5.2%
4	Large Quantity General Svc	145, 175	$ 41,665	$ 2,185	$ 43,849	5.2%
5	Large Quantity Interruptible Svc	150, 180	$ 11,705	$ 1,228	$ 12,933	10.5%
6	Other Revenue		$ 35,357	$ -	$ 35,357	0.0%
7	Total		$ 574,113	$ 53,145	$ 627,258	9.3%

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Allocation of Proposed Distribution Revenue
using PSNC's Proposed Allocation of Increase
and Design Day
Test Year Ended December 31, 2020
(Dollars in Thousands)

Line	Customer Class	Rate	Current Distribution Revenue (1)	Proposed Distribution Increase (2)	Proposed Distribution Revenue (3)	% Increase (4)
1	Residential	101, 102, 115	$ 228,291	$ 37,743	$ 266,034	16.5%
2	Small General Service	125, 126, 127	$ 50,545	$ 10,822	$ 61,367	21.4%
3	Medium General Service	140	$ 10,298	$ 1,168	$ 11,467	11.3%
4	Large Quantity General Svc	145, 175	$ 23,577	$ 2,185	$ 25,761	9.3%
5	Large Quantity Interruptible Svc	150, 180	$ 7,362	$ 1,228	$ 8,590	16.7%
6	Other Revenue		$ -	$ -	$ -	0.0%
7	Total		$ 320,074	$ 53,145	$ 373,219	16.6%

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Proposed Rate Design for Rate 175

Line	Description	Billing Units (1)	Present Rates (2)	Cost at Present Rates (3)	Proposed Rates (4)	Cost at Proposed Rates (5)	Proposed Increase Amount (6)	Proposed Increase Percent (7)
1	Facilities Charge ($/Mo.)	3,663	$ 300.00	$ 1,098,900	$300.00	$ 1,098,900	$ -	0.0%
	Energy Charge ($/therm)							
2	First 15,000 therms	43,775,946	$ 0.13900	$ 6,084,856	$ 0.17900	$ 7,835,894	$ 1,751,038	28.8%
3	Next 15,000 therms	23,662,709	$ 0.11835	$ 2,800,482	$ 0.15813	$ 3,741,784	$ 941,303	33.6%
4	Next 15,000 therms	16,090,255	$ 0.09989	$ 1,607,256	$ 0.13948	$ 2,244,269	$ 637,013	39.6%
5	Next 15,000 therms	11,864,080	$ 0.07579	$ 899,179	$ 0.11512	$ 1,365,793	$ 466,614	51.9%
6	Next 1,000,000 therms	97,680,420	$ 0.05573	$ 5,443,730	$ 0.09485	$ 9,264,988	$ 3,821,258	70.2%
7	Over 1,060,000 therms	17,577,890	$ 0.04872	$ 856,395	$ 0.07837	$ 1,377,579	$ 521,184	60.9%
8	Total	210,651,300		$17,691,897		$ 25,830,307	$ 8,138,410	46.0%
9	Total Cost			$18,790,797		$ 26,929,207	$ 8,138,410	43.3%

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Recommended Rate Design for Rate 175

Line	Description	Billing Units (1)	Present Rates (2)	Cost at Present Rates (3)	Recom-mended Rates (4)	Cost at Recommended Rates (5)	Recommended Increase Amount (6)	Recommended Increase Percent (7)
1	Facilities Charge ($/Mo.)	3,663	$ 300.00	$ 1,098,900	$300.00	$ 1,098,900	$ -	0.0%
	Energy Charge ($/therm)							
2	First 15,000 therms	43,775,946	$ 0.13900	$ 6,084,856	$ 0.15269	$ 6,684,215	$ 599,358	9.8%
3	Next 15,000 therms	23,662,709	$ 0.11835	$ 2,800,482	$ 0.13001	$ 3,076,329	$ 275,847	9.9%
4	Next 15,000 therms	16,090,255	$ 0.09989	$ 1,607,256	$ 0.10973	$ 1,765,570	$ 158,315	9.9%
5	Next 15,000 therms	11,864,080	$ 0.07579	$ 899,179	$ 0.08326	$ 987,748	$ 88,569	9.9%
6	Next 1,000,000 therms	97,680,420	$ 0.05573	$ 5,443,730	$ 0.06122	$ 5,979,937	$ 536,207	9.8%
7	Over 1,060,000 therms	17,577,890	$ 0.04872	$ 856,395	$ 0.05352	$ 940,750	$ 84,355	9.9%
8	Total	210,651,300		$17,691,897		$ 19,434,549	$ 1,742,652	9.9%
9	Total Cost			$18,790,797		$ 20,533,449	$ 1,742,652	9.3%

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Evergreen Packaging Data Request No. 1
July 19, 2021

1-6. Is it correct that Atrium Economics performed a cost allocation review or report for Manitoba Hydro-Centra Gas dated May 20, 2021? Provide all reports and documents associated with same.

RESPONSE:

Yes. The report can be viewed at the following link:

https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/natural_gas/cosmr_2021/01-1_appendix_1_review_of_cost_of_service_methodology_of_centra_prepared_by_atrium_economics_llc.pdf

Prepared by or under the supervision of: John D. Taylor, Managing Partner, Atrium Economics, LLC

Dated: July 26, 2021

ATRIUM ECONOMICS
CENTERED ON ENERGY

Manitoba Hydro – Centra Gas

Centra Gas Cost Allocation Review

May 20, 2021

Table of Contents

List of Tables

List of Figures

Appendices

1.0 Executive Summary

Manitoba Hydro ("Hydro") retained Atrium Economics, LLC ("Atrium") to review and assist in the regulatory approval process of the Cost-of-Service Study ("COSS") for its Centra Gas Manitoba Inc.'s ("Centra" or the "Company") natural gas operations. Atrium has prepared this report documenting and supporting our assessment of Centra's current COSS method in conformance with the regulatory requirements of the Manitoba Public Utilities Board ("MPUB").

Focusing on the trends of Canadian gas distribution utilities, Atrium reviewed the entirety of the Company's COSS method utilized in its current cost of service studies against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market.

In addition, Centra supplied information related to its gas transmission and distribution systems. Atrium consultants reviewed system maps and attended briefings by Centra personnel familiar with the Centra system. The information supplied insight into Centra's upstream transmission pipeline interconnections, distribution mains and operating pressures, as well as the location of the high-pressure transmission system. It also supplied additional understanding of certain customer groups and their usage and needs.

The primary purpose of a COSS is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. A complex part of the allocation process is the allocation of demand costs. Historically, several methodologies were used by gas utilities to develop allocation factors for the demand components of costs. Indeed, the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual identifies three fundamental methods for allocation of demand related costs: *Coincident Peak* methods, *Non-Coincident Peak* methods, and *Average and Excess* demand methods. Centra currently uses the *Peak & Average* method for the allocation of demand related costs, which is a simplified version of the Average and Excess demand method. This method has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

Atrium used foundational underlying principles applicable to every utility COSS; that is, the concept of *cost causation* for purposes of allocating costs to customer groups. Centra's COSS should stand on its own objective merits and costs are most appropriately allocated to the classes of service based on the design and operational considerations of the utility's system. Based on our review we make the following recommendations:

- *Replace Allocation of Transmission and Distribution Plant Using the Peak & Average Allocation Method with a Coincident Peak Day Allocation Method.* Atrium maintains that transmission and distribution plant is a function of the cumulative peak day demands of those customers served by those pipeline infrastructure investments and recommends the use of a Coincident Peak Day allocation of transmission mains and the demand component of distribution mains.
- *Refine Demand Allocation Factors using Design Day Peak* Design day demand directly measures the maximum gas demand requirements of Centra's customers, which create the need for the utility to acquire resources, build facilities, and incur fixed costs on an ongoing basis.

- *Directly Assign High Pressure Transmission Plant to Customers Where Appropriate.* Atrium recommends a direct assignment of the transmission mains that serve certain customers with no other allocation of the broader transmission system. As discussed in our report, if a direct linkage between a utility's customers and the particular costs incurred by the utility in serving those customers is established, that cost is considered a directly assignable cost.
- *Refresh the Development of the Customer Component of Distribution Mains.* It is Atrium's understanding that the current method used by Centra to determine the customer component has not been updated in recent years.
- *Consider a Seasonal Resource Stack-Based Analysis Approach to the Allocation of Upstream Capacity Resources.* Centra holds multiple third-party contracts for natural gas pipeline and storage capacity. The use of this third-party capacity and the associated costs demonstrates significant seasonal variations. Therefore, a seasonal resource stack-based analysis of each pipeline and storage capacity resource's contribution to the seasonal and peak day demands of its customers is most appropriate. Alternatively, Centra should use the winter season demand in excess of summer season demand.

2.0 Project Background

Hydro retained Atrium to review and assist in the regulatory approval process of the COSS for its Centra Gas Manitoba Inc.'s Centra natural gas operations. Atrium's project deliverable is a written report documenting and supporting our assessment of the adequacy of Centra's current COSS methodology in response to regulatory requirements of the MPUB and to ensure that the Company's costing methodology continues to adequately support its pricing of utility services.

Specifically, the key objectives for Atrium are:

A. Review of Centra's current COSS methodology, regulations, key issues of concern, raised by participants in Centra's last general rate application,

B. Compare Centra's current methodology to the best practices for similar natural gas distribution utilities, based on Atrium's view of the industry,

C. Develop a written report with recommendations that are appropriate to Centra given its particular circumstances that will ensure the COSS methodology continues to reflect cost causation principles and provides an appropriate basis for determining rates,

D. Develop comprehensive and detailed plans to convert methodologies and processes, where necessary to implement Atrium's recommendations; and

E. Assist Centra throughout the regulatory review of the proposed COSS methodology to ensure necessary approvals are achieved.

2.1 Atrium's Roles and Responsibilities

A. To thoroughly review Centra's current methodological approach used in its COSS and associated allocation studies and results,

B. To understand the system planning, operation, and engineering of Centra's gas business to assure that cost causation is properly reflected in its COSS,

C. To provide sufficient commentary on our recommendations and supporting information pertaining to alternative costing methodologies, the related treatment of costs, and the associated results so that Centra can adequately evaluate our findings and decide whether to propose changes in its subsequent COSS filing with the MPUB. We accomplish this objective by providing the Company with the rationale behind each of our assessments and more detailed commentary, where appropriate, on why and how certain potential issues may impact Centra; and

D. To document and explain our findings and recommendations in writing in a report presented to Centra.

2.2 Guiding Considerations

In conducting our review of Centra's gas COSS methodologies, Atrium was steered by the following guiding considerations:

A. The fundamental and underlying philosophy applicable to every utility COSS pertains to the concept of *cost causation* for purposes of allocating costs to customer groups.

B. Cost causation (or cost causality) addresses the question – Which customer or groups of customers cause the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

C. A key consideration is the ability to establish operating relationships between customer service requirements and the costs incurred by the utility in meeting those requirements (e.g., satisfying a customer's peak demand requirements through the incurrence of capacity-related costs to provide the required level of gas delivery service).

D. A utility's COSS should stand on its own objective merits. The costs should be assigned to the classes of service based on the design and operational considerations of the utility's system rather than on achieving results that support a desired outcome for the allocation of revenues to classes and/or rate design.

E. The current range of regulatory practices observed in the North American gas utility industry.

2.3 Atrium's Process for Evaluation of Centra's COSS

Atrium reviewed the overall structure, conceptual underpinnings, operational basis, computational consistency, and input data sources of the Company's COSS methodology utilized in its current cost of service studies against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service (i.e., total revenue requirement); and (2) current range of regulatory practices observed in the North American gas utility market, with a focus on the trends of Canadian gas distribution utilities.

As part of this task, we supplemented our existing knowledge of gas utility trends in these areas through the review of any existing information already gathered by Centra's staff and our additional research efforts to better understand the costing frameworks, specific costing techniques, and cost study results used by gas distribution utilities in Canada.

Finally, Atrium had discussions with engineering staff at Centra to gain a general understanding of its gas distribution system operations, and of the engineering practices and standards it utilizes when new customers are connected to its gas system. These considerations often can influence the choice of allocation methods for assigning mains, services, and meters to the utility's classes of service. Throughout the course of the work effort, Atrium and Centra team members discussed various issues and perspectives associated with the incurrence of costs and operation of Centra's distribution system.

Atrium has undertaken the following specific activities:

- Reviewed and discussed with Centra's staff the physical configuration and operations of its natural gas system, the acquisition of gas commodity and capacity-related resources from upstream suppliers, its market and customer base, and the load characteristics of its gas system and individual customer classes (e.g., peak day demand, design day demand, winter season loads, etc.).
- Reviewed a working copy of Centra's Cost of Service Study model and any narrative explanation of the underlying classification and allocation methods.
- Reviewed Centra's cost functionalization and classification methods. Centra currently groups its gas plant and expense elements according to six major functions: Production, Pipeline, Storage, Transmission, Distribution, and On Site (or Customer).
- Reviewed appropriateness of Centra's current allocation methods to assign plant and expense elements to its customer classes, with a focus on the following areas:
  - The appropriateness of Centra's current capacity (demand) cost allocation methods. To support this activity, we reviewed the Company's gas load characteristics, by customer class, to better understand the magnitude and timing of the peak demands its customers impose upon the gas system.
  - The issues raised in Centra's last General Rate Application with respect to the allocation of Transmission costs, including:
    - Use of Peak and Average for the allocation of transmission-related costs,
    - Cost allocation based on direct assignment,
    - Appropriateness of postage stamp rates currently used by Centra, and
    - Use of a zone of reasonableness in setting rates versus Centra's current method whereby the revenue to cost ratio is maintained at unity.
  - The appropriateness of Centra's minimum distribution system plant costing methodology and its application to customer-related distribution plant in service components, such as mains and services.
- Reviewed Centra's COSS structure to determine if the resulting unit costs are aligned properly relative to the unbundling of its current rate design for small volume users and industrial customers.
- Coordinated with Centra staff periodically through regularly scheduled telephonic status meetings, interviews, and information gathering.
- Reviewed Centra's current tariff to obtain a background and understanding of Centra's rate classes and current rates.

3.0 Theoretical Principles of Cost Allocation

The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. A cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecasted test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

3.1 Cost Causation

Cost studies are a basic tool of ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," which is another way of saying that those who cause the costs should pay the costs. Undue discrimination occurs when customers receiving the same service pay different amounts for the same service. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. We use the term "on average" because no two customers are exactly alike. Therefore, we determine costs and set cost-based rates for "typical" customers grouped by similar demand and usage patterns.

If those customer-related costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient, the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services

may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the utility system.

3.2 Characteristics of Utilities' Costs

The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs.[1] In addition, utility costs may be fixed or variable costs. Finally, utility costs exhibit significant economies of scale.[2]

These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Utilities are unusual in the relationship between fixed and variable costs, as the industry has a long history of recovering fixed costs through variable charges where no cost relationship exists. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-gas commodity related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, distribution main costs vary with either growing design day demand or a growing number of customers.

3.3 Allocation of Demand Related Capacity Costs

A complex part of the allocation process is the allocation of demand costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. It is not unusual for more than one demand cost allocation approach to be used in a cost of service study. Despite the use of different methodologies to allocate demand costs, there are three basic methodologies that form the foundation for the allocation process. The National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual identifies these three fundamental methods for allocation of demand related costs: *Coincident Peak* methods, *Non-Coincident Peak* methods, and *Average and Excess* Demand methods. Within each of these categories, there are numerous specific formulations of the methods.

The concept of *Coincident Peak* (CP) demand allocation is premised on the notion that investment in capacity is determined by the peak load(s) of the utility. Under this methodology, demand related costs

[1] Common costs occur when the fixed costs of providing service to one or more classes or the cost of proving multiple products to the same class use the same facilities and the use by one class precludes the use by another class (e.g., transmission or distribution pipeline peak capacity). Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions.
[2] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The Peak Demand allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day."

The *Average and Excess* (A&E) demand allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand, i.e., total class non-coincident demand minus average demand. The A&E method uses a weighted average of class average demands (weight = system load factor) and the "excess" demand (weight = one minus the system load factor). When the A&E method is used in combination with the system CP it has the mathematical result of double counting the class average demands. This is the primary reason that the A&E method is very rarely used in gas embedded cost of service studies.

A simplified version of this methodology is the *Peak and Average* (P&A) methodology. This cost methodology often gives equivalent weight to peak demands and average demands. Centra uses the system load factor to weight the average demand, and one minus the system load factor to weight the peak day demand. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

The *Non-Coincident Peak* (NCP) demand allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each rate class' maximum demand, irrespective of the time of the system peak. The NCP allocation method is rarely used for gas distribution utilities. The method is more commonplace in electric cost of service studies where NCPs have some relevance to cost causation.

The NCP method penalizes those customer classes that use the distribution system most efficiently; that is, those customers whose system peak use is low relative to their average use (high load-factor customers). Conversely, the CP method gives proper recognition to the reduced costs that high load-factor customers impose on the system vis-à-vis customers with high system peak use relative to average use (low load-factor customers). It is indisputable that customers who use the gas system during peak periods are more expensive to serve than off-peak users. It costs less to serve off-peak users, customers who use the system without adding demand requirements to the system peak, because Centra does not have to build additional capacity into its gas distribution facilities to deliver the gas. Thus, the existing distribution system is more fully and efficiently utilized. Therefore, a customer with a high load-factor is more beneficial to the efficient utilization of the gas system than one whose load factor is low.

In summary, when a large portion of the gas utility's capacity-related cost of its gas distribution system is allocated to the customer classes on the basis of off-peak demand (e.g., under the NCP method and the average component of the P&A method), the customer classes with the efficient usage characteristics (high load-factor) are penalized because those customer classes will ultimately pay a relatively higher share of capacity-related costs than would a low load-factor customer class; and conversely, the low load-factor customers benefit from this subsidy.

4.0 Review of Capacity Cost Allocation

As discussed earlier, the process of cost allocation is predicated on theoretical principles of cost causation. However, the process is not an exact science. Negotiations among utilities, customer groups, and other stakeholders, as well as regulatory agency directives may supersede the fundamental outcome of the underlying allocation process to further the public interest. For example, the U.S. Federal Energy Regulatory Commission ("FERC") has historically wrestled with which factor or factors to consider as dispositive. Among them, the FERC has evaluated such probative considerations such as demand and diversity, economic factors, firm versus interruptible requirements for service, and various other factors.

4.1 Historical Context for Centra's Use of Peak & Average

Supporters of the P&A method contend that gas pipelines are built to deliver gas volumes to customers, and that demand or capacity costs are incurred to serve the combination of peak-period and annual customer requirements. These analysts often point to this principle as the foundation for the 1952 *Seaboard* decision by the FERC, as the most frequently referred to precedent on the subject. The FERC determined that both peak and annual use were of equal importance in determining cost responsibility and thus established the Seaboard methodology. Under *Seaboard*, fixed costs associated with transmission and storage functions were apportioned 50 percent to the demand category and 50 percent to the commodity category.

While generally referred to as an allocation method, the Seaboard method is really a cost classification method. As mentioned above, the FERC has based its cost classification and allocation decisions, at various points in time, with less regard to cost causation principles and with primary emphasis on addressing the implications of a set of facts and conditions in energy markets on gas pipeline rate design. Rate design methods at FERC have changed and evolved over the years to achieve various policy objectives, while satisfying the fundamental tenants of rate design theory. This process of cost allocation is the context in which Atrium evaluated the allocation method currently used by Centra.

Atrium recognizes that Centra's use of the P&A allocation methodology was approved by the MPUB in Order 107/96, dated October 17, 1996, and has been used consistently by Centra since that time. The following explanation is quoted from page 15 of the evidence provided by R. J. Rudden and Associates in the "Cost of Service Review" dated May 31, 1996, which was filed as part of Centra's Application.

> "Peak and Average: Each class' contribution to a weighted average of design day demand and average daily demand. This approach to allocation makes a recognition that average daily demand (commodity) plays some role in determining the level of demand-related costs. This proposition is not based on any engineering basis, but rather reflects an equity consideration that higher load factor customers use the capacity more heavily than lower load factor customers, and therefore should receive a greater share of its total cost."[3]

[3] 1996 Cost of Service Review by R. J. Rudden Associates Inc., Page 15 of 22.

A proper characterization of the P&A methodology is as a utilization-based study as opposed to a cost-causation study. Centra has recognized this fact in other statements from prior cost of service reviews.

> "The [P&A] allocator is not purely cost-causal in nature, as the use of the average component reflects some customer-to-customer equity considerations in that higher load factor customers use the system with more intensity than do lower load factor customers."[4]

Atrium's disagreement with this point of view is grounded in the fact that high load factor customers use the pipeline system more consistently than low load factor customers, which directly translates into using the system more efficiently (i.e., less unused capacity throughout the year). The implication from the quoted statement above is that because high load factor customers use their portion of the system more efficiently and are able to take advantage of the delivery of natural gas on a more consistent basis, they are somehow not contributing sufficiently to the cost of the system; or rather, that the value they receive from the system exceeds the cost to serve them (i.e., the customer-to-customer equity considerations).

The P&A method penalizes high load factor customer classes in the following manner. Economies of scale are always recognized when a gas utility sizes its distribution mains to satisfy peak capacity requirements of its customers. The concept of economies of scale drives overall costs incurred by a gas utility for its gas distribution mains and these economies of scale are reflected in Centra's embedded costs of distribution mains. However, economies of scale affect the sizing of distribution mains – but not the allocation of their resulting costs. The economies of scale enjoyed by a gas utility are created by the interaction of the capacity requirements of all its customers. Centra does not plan for the changing needs of its distribution system by examining the capacity requirements of any one customer class or by conducting capacity planning by first disaggregating its capacity needs into "average demand requirements" and "peak demand requirements." Rather, it examines its capacity needs in the aggregate based on the peak hour demands on its design day for all of its customers or for the group of customers added to the existing distribution system at any point in time.

The fallacy in the P&A allocation method becomes clear for a customer class that exhibits a high load-factor. According to the P&A allocation method, this class should not receive any economies of scale benefits because the class' average demand is high relative to its peak demand. Yet, the engineering reality is that this class should receive economies of scale benefits just as any other class to the extent the capacity requirements of this class at the time these customers were connected to the gas utility's distribution grid created economies of scale in the costs of expanding the grid to accommodate them.

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

[4] 2009/10 & 2010/11 General Rate Application Response to Information Requests of the Public Utilities Board of Manitoba, PUB/CENTRA 1-106, March 31,2009, at 4:15 – 18.

A cost-causation study is based on both the engineering and operational practices of a gas utility, while a utilization-based study relies more heavily on the energy consumption characteristics of the customers served by the utility. The argument regarding the building of pipe to serve customers on a "sustained year-round basis" merely confirms a basic fact known to distribution facilities engineers and analysts alike. Transmission and distribution mains designed to meet peak hour or peak day gas flows can also accommodate minimum flows or any gas flows in between, including average flows. Annual throughput is too generalized a service requirement of customers to use to properly capture the cost causation factors attributable to transmission and distribution mains.

Atrium reviewed the approved cost of service methods used by natural gas LDCs throughout Canada from publicly available information. A brief summary of the cost of service methods for transmission and distribution plant for ATCO Gas, APEX, Enbridge, FortisBC and Liberty Gas are provided in **Section 8** of this report. None of the LDCs surveyed use the P&A method for Transmission or Distribution plant.

4.2 Centra's Coincident Peak Day Methodology

Centra's Coincident Peak ("CP") day in its P&A allocator is based on the following methodology:

- Centra's forecast assumes an average winter and provides an average peak day value based on the previous three years of historical data. Historical data is sourced from Centra's Gas SCADA system and Banner Billing System. Gas SCADA has hourly information for all 26 service points from the TransCanada Energy ("TCPL") pipeline in Manitoba, along with all complex gas customers (HVF, MLF, INT, SPEC-T, PS).
- Hourly information is used to tabulate gas daily information (9AM to 9AM) for all complex customers classes and a total for the SGS Residential, SGS Commercial and LGS classes. All complex gas customers have daily information to provide input on the peak contribution and to help identify the peak contribution for the SGS Residential, SGS Commercial and LGS classes, from which a weather normalization model is developed.
- Using monthly billing information, the model outputs a baseload and degree day heating (DDH) coefficients to be utilized to calculate class contribution for a normal peak day. Those coefficients are used to approximate the class contribution for the SGS Residential, SGS Commercial and LGS classes.

4.3 Recommended Allocation Method – Design Day Peak Demand

While Centra's CP day is an appropriate construct for a historical peak demand allocator, Atrium recommends the use of Centra's design day demand as an improvement to using its actual peak day demand or an historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These include:

- A Local Distribution Company's (LDC's) gas system is designed, and consequently capacity related costs are incurred, to meet design day demand. In contrast, these costs are not incurred on the basis of an average of peak demands.

- Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.
- Because it aligns with a more consistent reference; that is, the fixed costs of transmission and distribution plant investment, and not dependent on the vagaries of changing weather patterns, design day demand provides more stable cost allocation results over time than the P&A allocation method.

From our discussions with Centra personnel, Atrium noted that interruptible customers are excluded from consideration in Centra's contracting for upstream gas supply-related capacity resources. However, interruptible loads are included as part of Centra's transmission and distribution system design day planning criteria. Further, the interruptible customers have not been curtailed for system reliability reasons for over twenty years.[5] Therefore, Atrium recommends interruptible customers' demands should be included in the system peak day demand allocation, which would address concerns that interruptible customers would not contribute to the recovery of capacity costs under a CP method, resulting in shifting capacity costs to the firm customer classes. Centra's current P&A method attributes some capacity costs to the Interruptible customer class through the "average", or throughput, component of the P&A allocator.

Centra's system infrastructure, especially transmission and distribution mains, are sized and built to accommodate all customer demands on that winter day under the severest of recorded temperature and weather conditions in order to insure safe and reliable service to its customers. Out of necessity, gas transmission and distribution mains in Manitoba must be sized to meet design weather conditions. Otherwise, the distribution system could fail repeatedly and predictably in winter.

Centra determines the peak load on its pipeline system using customer usage as an input. The load estimation process in performed using DNV's Synergi Customer Management Model (CMM). The process uses individual customer meter information to determine a non-heat dependent base load and a temperature dependent load component. Base and temperature dependent load components are calculated and stored in a database that includes customer information from 1999 to the present. The information is statistically compared each year for each customer and to all other customers within the rate class and outliers reviewed and adjusted. The load from all customers on a pipeline segment are combined and used to load a hydraulic model by Degree Day for any design or capacity condition. [6]

Centra's use of a long-term design weather standard allows for consistent system capacity planning criteria when making infrastructure investments intended to provide reliable service for decades. It is logically consistent and administratively efficient to recognize this same standard when performing cost of service studies.

The use of design day demand provides more stable cost allocation results over time. By definition, Centra's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of Centra's gas system and supply capacity resource

[5] 2019/20 General Rate, Centra Response to First Round Information Requests of Consumers Association of Canada (Manitoba), CAC/Centra 1 – 24(a).
[6] Centra's design day average temperature, base temperature, and corresponding level of degree days are not stated in this report, as this information is considered commercially sensitive information by Centra.

portfolio would tend to vary and make the installation of facilities and acquisition of supply related capacity resources a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days. It is the expert opinion of Atrium, there is no better way to capture the true cost of Centra's operations than to utilize its design peak day requirements within its cost of service studies.

5.0 Review of Centra's Gas Transmission and Distribution Systems

Centra provided information related to its gas transmission and distribution systems. Atrium consultants reviewed system maps and were given briefings by Centra personnel familiar with the Centra system. Areas of review included:

- Upstream transmission pipeline interconnections (i.e., TCPL and TransGas) and City Gate stations,
- Location of Centra's high-pressure transmission system
- Location of large Mainline customers, the Special Contract Class, and the Manitoba Hydro Power Stations on the Centra gas transmission system, and
- Distribution mains and operating pressures

Presented in **Appendix A** are gas pipeline schematics that provide a representation of all Centra's transmission pressure pipeline systems, including the 27 primary stations connected to TCPL or TransGas, and the 119 Gate Stations. The Winnipeg high-pressure pipeline segments represent the majority of the high-pressure pipelines (198 km) in the Centra system.

Table 1 below provides a description and application of the Centra pipeline system operating pressure classifications.

Table 1 Pipeline System Pressure Classifications

Pressure Class	Pressure Range		Application
	PSIG	kPa	
Distribution	0 – 100	0 – 700	A generic term for the broad range of pressures used for gas distribution. Specifically, the pressure in gas distribution systems that deliver gas directly to customer meter sets with only one stage of pressure regulation.
High or Intermediate	101 – 275	701 – 1900	This pressure range is found in intermediate lines that deliver gas from a transmission line to a distribution system. This pressure range is higher than distribution pressure supplied and less than transmission pressure.
Transmission	> 275	> 1900	The pressure range normally used in transmission lines.

5.1 Allocation of Transmission Plant

5.1.1 Current Allocation Method – Peak & Average

Atrium's critical review of the use of the P&A allocation method for capacity costs discussed in **Section 4.1** applies to Centra's transmission mains. Currently, Centra's transmission plant is allocated using the P&A allocation method using the system load factor to weight the average demand, and one minus the system load factor to weight the peak day demand.

5.1.2 Recommended Allocation Method – Design Day Peak

As discussed in **Section 4.3**, Atrium recommends the use of a coincident peak allocation of transmission plant to the rate classes based on the proportion to their design day peak load requirements.

Centra must consistently rely upon design day demand in the acquisition of its upstream gas supply-related capacity resources and in the design of its own transmission and distribution facilities required to service its customers in its 26 service areas connected to TCPL. Perhaps more importantly, design day demand directly measures the gas demand requirements of the Company's customers which create the need for the Company to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis.

5.2 Direct Assignment of Transmission Plant

As discussed in **Section 3.1**, cost causation principles dictate that a customer or groups of customers that cause the utility to incur particular costs should be responsible for those costs. If a direct linkage between a utility's customers and the particular costs incurred by the utility in serving those customers is established, that cost is deemed a directly assignable cost.

In other words, the term direct assignment relates to a specific identification and isolation of capital investment and/or expense incurred exclusively to serve a specific customer or group of customers. A direct assignment best reflects the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to properly reflect the relationship between cost causation and cost responsibility. When a direct assignment is not possible due to the nature of the cost (e.g., a joint or common cost), the cost analyst may need to rely upon other more generalized allocation methods or an allocation methodology supported by a special study, as is done with costs associated with meters and services.

5.2.1 Recommended Allocation Method – Direct Assignment

Atrium recommends that the Special Contact customer receive a direct assignment of the transmission mains that serve its industrial facility. Atrium reviewed the Special Contract customer's contract terms; interrogatories and testimony from Centra's last rate proceeding; details of the special contract customer's service characteristics; physical location of the customer on the Centra transmission system; significant historical load changes; and other relevant information for consideration as we evaluated alternative costing methods. Based on this review we determined the following:

- The transmission pipeline segments are exclusively used to provide service to the Special Contract customer.
- Under normal operating conditions, the transmission lines providing service operate in isolation from the remainder of the transmission system.
- A direct interconnect with TCPL via Centra's Brandon primary gate station serves the entire load requirements of the Special Contract customer's industrial facilities.
- The transmission pipeline segments operate at a higher pressure than most of the rest of the Centra system; the Special Contract customer requires higher pressures to maintain plant

operations, having entered into a minimum delivery pressure agreement with the upstream transmission pipeline, TCPL, to promote operational stability.

- The Special Contract customer requires non-odorized gas, which necessitates isolation of the parallel transmission pipelines from which the Special Contract customer receives service and inhibits the active interconnection of these pipeline segments with the broader transmission system.
- The remainder of the Centra transmission system is fully odorized, physically separated by valve stations which remain closed under normal operating conditions and receives only one-way pressure and capacity support in an emergency situation from the transmission pipelines that serve the Special Contract customer.

The following schematic diagram, an excerpt from Centra's system maps, in **Figure 1**, shows the location of the Special Contract customer and one of the two Manitoba Hydro Power Stations, on the Centra transmission system.

As shown in **Figure 1,** gas flows to the Special Contract customer through the Brandon Primary gate station and downstream through a 6" and 12" transmission pipeline to the customer's industrial facility. Further, the schematic diagram indicates that the valves between the odorized transmission pipeline and the high-pressure 6" transmission line are operating in the closed position. The parallel high-pressure transmission lines are designated as "unodorized".

A review of this schematic diagram, in addition to the operational information provided by Centra, demonstrates that the gas flowing to the special contract customer is exclusively from the Brandon Primary gate station through the 6" and 12" lines and to the Special Contract customer's industrial facility. The normal operation of these pipelines has evolved to meet the requirements of the Special Contract customer and, since approximately 2011, they have been dedicated to the purpose of serving the maximum demand, pressure requirements and non-odorized gas supply of the Special Contract customer. It is entirely appropriate to directly assign the cost responsibility for these pipeline facilities to the customer when a nexus between the cost incurrence and the customer can be identified. Therefore, Atrium recommends that the demand-related cost for these transmission mains be directly assigned to the Special Contract customer and no allocation of the broader transmission system capacity.

Similar to the Special Contract customer, Atrium recommends that there be a direct assignment to the Power Station Class for the pipeline facilities directly serving the Manitoba Hydro Power Station, shown as GS-192 in **Figure 1**. The 12" and 10" pipelines serving the combustion turbine power plant run parallel to the pipelines serving the Special Contract customer. Further, the Power Station Class should not receive an allocation of the broader transmission system capacity related to this power station's demand requirements.

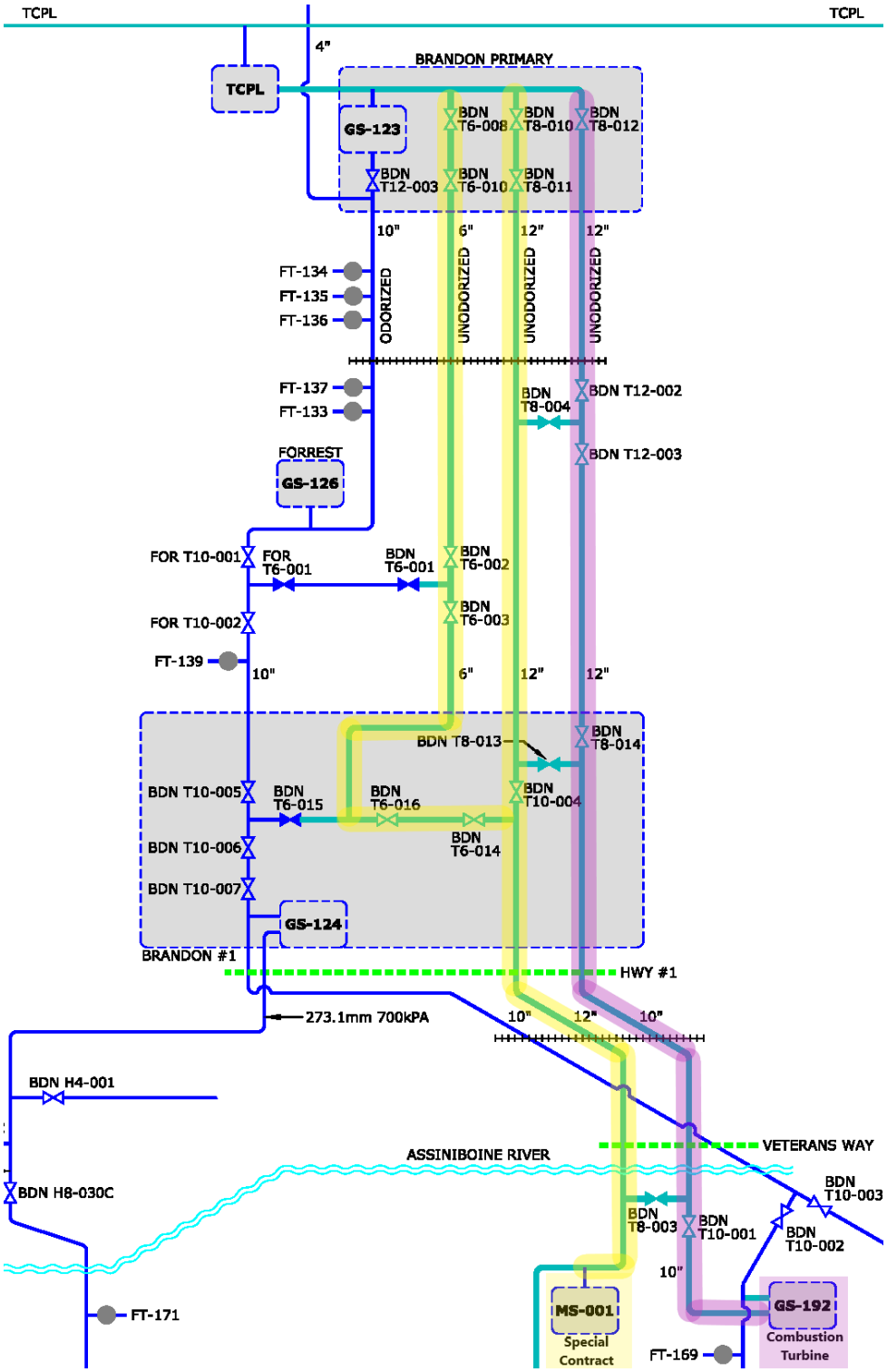


Figure 1 Schematic diagram of dedicated transmission lines for direct assignment

5.2.2 Allocation of Transmission Plant to Mainline Customers

As mentioned earlier in this **Section 5**, Atrium reviewed system maps and were given briefings by Centra personnel familiar with the Centra system, including commercially sensitive detailed descriptions of each Mainline customer and accompanying pipeline schematics, which Centra considers to be confidential. The Mainline customers are dispersed throughout the Centra transmission system and are located on transmission pipelines that serve both upstream and downstream load centers, ranging from transmission pressures of 600 PSIG to the upper range of what is currently classified as distribution pressure in **Table 1**. Based on our review of the transmission pipelines serving individual Mainline Class customers, it is Atrium's view that it is appropriate for the Mainline Class to receive a full allocation of the transmission system plant. However, the characteristics previously discussed that are applicable to the Special Contract customer do not apply to individual Mainline customers; and therefore, these customers are not candidates for a direct assignment of specific transmission pipeline related plant.

5.2.3 Postage Stamp Ratemaking

Postage stamp ratemaking is a cost allocation methodology whereby transmission and/or distribution plant investment across the entire system are aggregated for the purpose of allocation to all customer classes without regard to the geographic location of individual or groups of customers on the system. Centra has a consistent history of postage stamp ratemaking for several decades. As correctly stated in recent evidence filed by the Consumers' Association of Canada (Manitoba Branch) ("CAC"), "[t]his is the accepted approach to ratemaking in most North American jurisdictions."[7] In fact, most exceptions to the use of postage stamp ratemaking in the U.S. are found in the interstate pipeline industry regulated by the FERC and are primarily limited to long-line interstate pipelines crossing many states, with a limited number of production regions and gas Local Distribution Company ("LDC") customers located in regional load centers stretched out along the length of the pipeline. These pipelines generally use a form of mileage-based or zone-based cost allocation. One long-line, interstate pipeline that employs postage stamp ratemaking is the Williams Northwest pipeline, a 4,000-mile bi-directional transmission system crossing the states of Washington, Oregon, Idaho, Wyoming, Utah, and Colorado. Northwest's bi-directional system provides access to British Columbia, Alberta, Rocky Mountain and San Juan Basin (New Mexico) gas supplies. However, under FERC rules, Williams Northwest can and does charge incremental rates (versus rolled-in rates) for expansion capacity investments, which are charged to customers contracting for the capacity additions. This would not be a typical practice under postage stamp ratemaking.

Postage stamp ratemaking in Manitoba for electric utility operations is mandated by the Provincial Government under legislation enacted in 2001.[8] Centra's use of postage stamp ratemaking is consistent with the electric utility requirements. Based on Atrium's review of Centra's transmission and distribution pipeline systems, including the 27 primary stations connected to either TCPL or TransGas, and the 119 Gate Stations, we find no apparent support for a departure from postage stamp ratemaking policy followed by Centra.

[7] Evidence Prepared by Darren Rainkie & Kelly Derksen on Behalf of Consumers' Association of Canada (Manitoba Branch, Centra Gas Manitoba, Inc. 2019/2020 General Rate Application, June 26, 2019, at 95:23 – 24.
[8] Ibid.

5.3 Allocation of Distribution Mains

5.3.1 Current Allocation Method – Peak & Average, with Customer Component

Atrium's critical review of the use of the P&A allocation method for transmission plant discussed in **Section 4.1** applies equally to Centras' distribution mains. Currently, distribution mains are classified as 33.3% customer-related and 66.6% demand-related. The current method used by Centra to determine the customer component has not been revisited in many years.

5.3.2 Recommended Allocation Method – Design Day Peak with Customer Component

It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the customer classes that cause Centra to incur the costs of this plant investment and the related operating and maintenance expenses are charged with these costs, distribution mains should be allocated to the rate classes in proportion to their design day peak load requirements and number of customers.

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

5.3.3 Customer Component of Mains

Atrium understands that Centra is currently conducting a review of its distribution mains data in its plant accounting system, which may allow it to be organized in such a manner that will facilitate the performance of a new study to determine the customer component of its distribution mains.

The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, the Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, published by the American Gas Association, describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the utilization of one or the other of these two methods to determine a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and widely used approach in the gas industry.

5.4 Special Studies for the Allocation of Distribution Plant

Service Lines – Centra determines the cost per customer for service lines by compiling vintage year installed costs and number of services by pipe size. Centra maintains this service line installation data beginning in 1966. Centra uses this data to calculate the average cost per service by pipe size for SGS and LGS customers. Centra compiles the number of services by size for residential and commercial SGS and LGS, then uses this information along with the average cost per service size to calculate the class average cost per service. For the classes of larger customers, Centra compiles the installed costs of each customer's service line to calculate an average cost per service for the class. The customer class average costs per service at the time of the service line study are used to weight the number of customers in the cost of service study to determine the allocation of services costs.

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

Meters – Centra determines the cost per customer for meters by compiling the number of installed meters by size and/or type. A reconciliation is performed of meters used for billing, non-billing meters, and un-installed inventory. The complex meters costs are compiled for the large customers (classes HVF, ML, INT, PS, and SC). The number of billing meters by class are valued at the current inventory unit cost and compiled to provide a total current cost of meters by class. Finally, an average meter cost per customer is summarized by class.

The detailed process followed by Centra is one of the closest approaches to specific identification of the actual cost of each meter and service line by customer in each of the customer classes. However, for future service line studies, we recommend indexing the vintage year data to current year costs for a more equivalent comparison.

5.5 Special Studies for the Allocation of O&M, Customer Service, and Administrative Expenses

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

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

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

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

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

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

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

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

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

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

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

DSM – Allocated to the customer classes based on the forecasted participation by customer class.

6.0 Gas Supply Resource Allocation

6.1 Pipeline Capacity Costs

Centra holds multiple contracts for pipeline capacity on TCPL, some for twelve months at varying Maximum Daily Quantities (GJ/day) from the Empress pipeline interconnect at the Alberta border to Centra's delivery points on its transmission system; others for twelve months from the Emerson interconnect at the Canada/U.S. border to Centra's delivery point; and two seasonal contracts – one contract for five winter months of transportation of storage gas withdrawals from the Emerson U.S. border interconnection with Great Lakes Gas Transmission ("GLGT") to Centra's service area, and one contract for seven months of storage gas injections to the same pipeline interconnection at Emerson with GLGT. Centra also holds one twelve-month contract on Nova Gas Transmission for transportation from AECO hub in Alberta to the TCPL mainline at Empress.

Centra also holds companion seasonal pipeline capacity on GLGT and ANR Pipeline Company ("ANR") pipelines in the U.S. for storage gas injections to and withdrawals from ANR's underground gas storage facilities in Michigan, and for supplemental gas purchases in the U.S. Mapping of the Winter and Summer operation of the various upstream pipeline capacity resources are depicted in **Appendix B**.

6.2 Contracted Storage Capacity Costs

Centra contracts with ANR Storage for total GJ of gas storage capacity and (GJ/day) deliverability for summer injections and winter withdrawals.

6.3 Current Allocation Method – Peak & Average

Centra currently relies on the P&A allocation method for contracted year-round, long-line, interprovincial and interstate pipeline capacity, contracted storage capacity, as well as any fixed costs of Supplemental Supply. As stated earlier in Atrium's critique of the P&A cost allocation method, Centra must consistently rely upon the cumulative peak day demands of its customers in the acquisition of upstream gas supply-related pipeline and gas storage capacity resources required to provide service its firm service customers in its 26 service areas connected to TCPL. The only variable costs related to these upstream capacity resources are typically for fuel and/or shrinkage.

6.4 Recommended Allocation Method – Seasonal Resource Stack Based Analysis

Given Centra's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, that drives Centra to plan for and use upstream pipeline and storage capacity resources. Centra seeks the least-cost mix of available pipeline and storage capacity resources that can meet its design-day peak standard, including seasonal pipeline capacity under contract with ANR and GLGT, and additional year-round pipeline capacity under contract with TCPL and NGTL.

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

demands vis-a-vis storage injections as well as peak day. An example of this type of capacity resource analysis is depicted in the schematic diagram in **Figure 2**, below.

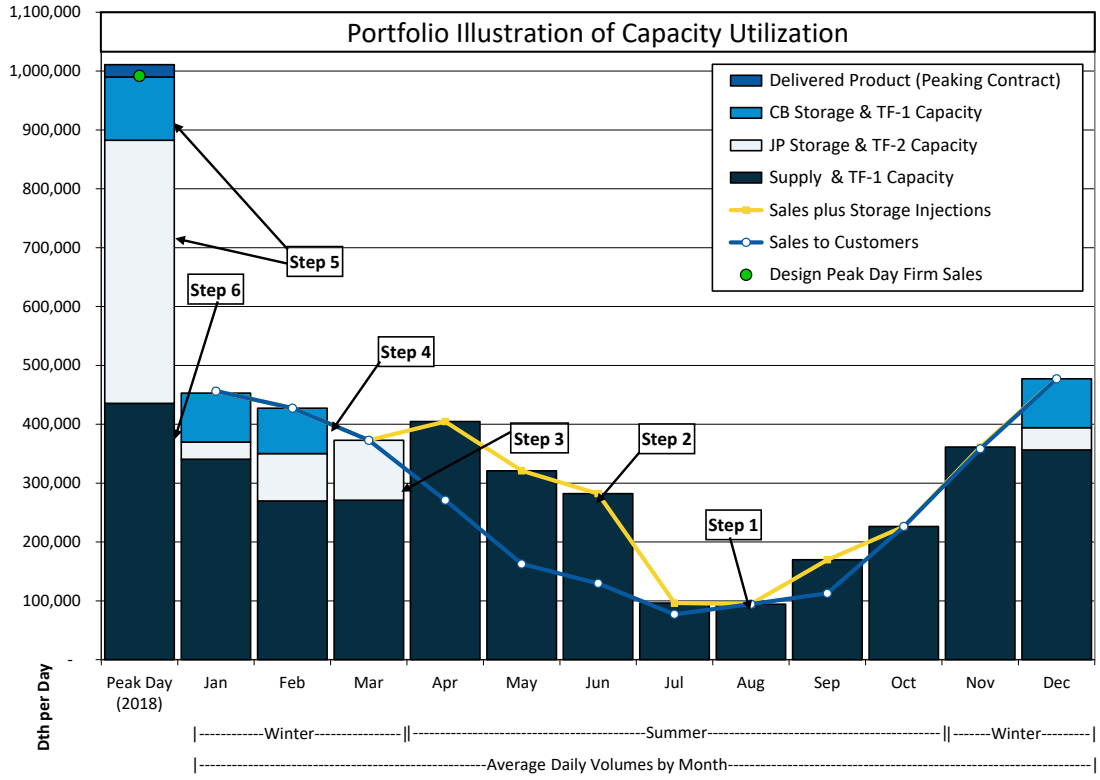


Figure 2 Illustrative example of capacity portfolio utilization

The underlying analysis is a logical progression of the steps to identify why and when capacity is needed, and thus gives guidance as to how to allocate the related costs. **Figure 2** does not and is not intended to reflect Centra's actual customer demand or supply-related capacity resources and is provided for illustrative purposes only.

6.4.1 Alternative Gas Supply Resource Allocation Method

In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand.[9] Winter season throughput would be an alternative allocation method for Supplemental Supply. An alternative allocation method for year-round pipeline capacity should be peak day demand, at the design day level. For interruptible customers, Centra should consider the use of a 100% load factor contribution to the peak day allocator. This will prevent these customers from

[9] The Winter Excess Demand allocation is calculated as each customer class' contribution to the average monthly throughput for November through March (winter) minus the average monthly throughput for April through October (summer). *Excess Winter Season Demand = Winter Monthly Avg – Summer Monthly Avg.*

escaping some peak day responsibility; that is, if Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group.

7.0 Revenue Allocation and Rate Design

7.1 Zone of Reasonableness for Revenue Allocation

Historically, Centra has followed the practice of establishing class revenue responsibility by setting rates based on "unity" or a revenue to cost ratio ("R|C") of 1.00. This has been facilitated by Centra's use of the P&A cost of service methodology, which includes non-cost causation factors, such as "customer-to-customer equity considerations," to establish cost responsibility by class. Centra's cost allocation study results are then used mechanistically to set revenue responsibility for each customer class equal to their allocated costs, resulting in a R|C ratio of 1.00 or unity. Centra's practice of setting class revenue responsibility to unity has been in place since 1997, as approved by the MPUB in Order 8/97. Prior to that time, Centra used a zone of reasonableness of 97% - 103% of unity.

Atrium believes that non-cost causation considerations should be addressed outside of the cost of service study process, reflecting revenue allocation and rate design principles such as non-discrimination (e.g., fairness and equity)[10], which may impact judgements regarding a sufficient zone of reasonableness.

We have taken note of excerpts from MPUB Orders that reveal its statements on ratemaking principles that align with our views on the subject. In Order 164/16 (page 27), the MPUB stated:

> "…the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage."
>
> "…ratemaking principles and goals of rate stability and gradualism, fairness and equity, efficiency, simplicity and competitiveness of rates should be considered in a GRA and not in the COSS."[11]

In Atrium's experience, many utilities and regulatory commissions recognize a zone of reasonableness in setting class revenue responsibility, with the use of parity ratios as a guide, and we recommend that it be considered in this instance whereby a full cost of service methodological review has been undertaken.

7.2 Alignment of Unit Costs and Rate Design

Atrium reviewed Centra's COSS structure to determine if the resulting unit costs are aligned properly relative to the unbundling of its current rate design for small volume users and industrial customers. From our review of the unit costs in Centra's COSS model we made the determinations below.

- Basic Monthly Charge – The Basic Monthly Charge for the SGS Residential, SGS Commercial, and LGS classes have been established at $14.00 and $77.00 per month, respectively, and do not

[10] The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.
[11] Centra 2019/2020 Natural Gas Rate Application, Direct Examination of Andrew McLaren on Behalf of the Industrial Gas Users, August 16, 2019, at 9.

adjust with changes to the unit costs. Centra's current unit cost for SGS is $20.79, and for LGS it is $106.38. The Basic Monthly Charge for all other classes is set equal to the unit cost of service.

- Upstream Commodity – The Upstream Commodity Rates (transportation to Centra) for all customer classes are set at the unit cost of service.
- Demand Charge – The Monthly Demand Charge applies to the HVF, CO-OP, ML, SC, GS, and INT, SPEC-T, and PS classes.
  - For HVF and INT the Monthly Demand Charge is set at 65% of the unit cost.
  - For the other applicable customer classes the Monthly Demand Charge is set at the unit cost of service.
- Downstream Commodity –
  - The Downstream Commodity Volumetric Charges for the SGS Residential, SGS Commercial, and LGS classes are set at the total downstream costs less the Basic Monthly Charge revenue, divided by volumes.
  - The Downstream Commodity Volumetric Charge for HVF and INT is set equal to 35% of the demand costs plus the downstream commodity costs divided by volumes.
  - The Downstream Commodity Volumetric Charge for all other customer classes is set equal to the downstream commodity costs divided by volumes. (CO-OP is set at $0.0001 due to rounding of significant digits).

Atrium finds that the cost of service study unit costs informs Centra's rate design. Some of the rate components reflected 100% of the related unit costs, while others are indexed to the unit costs based on established parameters.

8.0 Canadian Gas LDC Cost of Service Methods

Atrium reviewed the approved cost of service methods used by Gas LDCs throughout Canada from publicly available information. A brief summary of the cost of service methods for transmission and distribution plant for ATCO Gas, APEX, Enbridge, FortisBC and Liberty Gas are provided below. The full summaries are provided in **Appendix C**.

APEX

APEX was formerly known as AltaGas Utilities Inc. and is regulated by the Alberta Utilities Commission. APEX classifies transmission mains as 100% demand-related and allocated to customer classes based on coincident peak demand. Distribution mains are classified as 56.5% demand-related and 43.5% customer-related based on a combination of a minimum system study and a value of service (or "benefits") approach called the Volume Length Method as the result of a settlement agreement. The demand-related portion of distribution mains is allocated to customer classes based on non-coincident peak, primarily to allocate a portion of demand to seasonal use customers that do not operate in the winter months.

ATCO Gas

ATCO Gas is regulated by the Alberta Utilities Commission. ATCO Gas's transmission services are provided by a third-party and the costs are recovered through rate rider. Distribution mains are classified as 65% demand-related and 35% customer-related based on a negotiated settlement agreement. ATCO Gas' minimum plant study resulted in a customer component of mains higher than 35%. The demand-related portion of distribution mains is allocated to customer classes based on non-coincident peak, which is calculated as the maximum expected demand by rate class at the extreme cold temperature plus the demands of seasonal customers such as asphalt plants and irrigation customers.

Enbridge Gas Distribution Inc

Enbridge Gas Distribution Inc. ("Enbridge") was formerly known as Union Gas and is regulated by the Ontario Energy Board. Enbridge's transmission system is primarily used to deliver gas from storage fields to the distribution system. Transmission mains are classified as demand-related and allocated to customer classes based on a combination of volume, storage, and excess of peak day over average winter demand. Distribution mains are classified differently based on operating pressure. The higher pressure distribution mains are classified as 100% demand-related, and the low pressure mains are split classified as 44% demand-related and 56% customer-related based on a minimum system study. The demand-related portion of distribution mains is allocated to customer classes based on the coincident peak of each of the three pressure systems.

FortisBC

FortisBC is regulated by the British Columbia Utilities Commission. FortisBC classifies transmission mains as 100% demand-related and allocated to customer classes based on coincident peak demand. Distribution mains are classified as demand-related and customer-related based on a minimum system study which includes an adjustment for the carrying capacity for the minimum sized pipe. The demand-related portion of distribution mains is allocated to customer classes based on coincident peak calculated using test year load and a three-year average load factor for each of FortisBC's five regions.

Liberty NB

Liberty NB was formerly known as Enbridge Gas New Brunswick and is regulated by the New Brunswick Energy Utilities Board. Liberty NB does not have transmission mains. Distribution mains are classified differently based on material. Steel distribution mains are classified as 100% demand-related. Plastic distribution mains are classified as 56% demand-related and 44% customer-related based on a minimum system study. The demand-related portion of distribution mains is allocated to customer classes based on design day peak.

9.0 Findings and Summary Conclusions

In conducting our review of Centra's gas COSS methodologies, Atrium has adhered to the foundational underlying principle applicable to every utility COSS; that is, the concept of *cost causation* for purposes of allocating costs to customer groups. In doing so, we have evaluated the ability of Centra's COSS to adequately establish the operating relationships between customer service requirements and the costs incurred by Centra in meeting those requirements (e.g., satisfying a customer's peak demand requirements through the incurrence of capacity-related costs to provide the required level of gas delivery service.

Fundamentally, we believe Centra's COSS should stand on its own objective merits such that costs are assigned to the classes of service based on the design and operational considerations of the utility's system rather than on achieving results that support a desired outcome for the allocation of revenues to classes and/or rate design. It is through this lens that we have offered the following findings and recommendations:

- Replace Peak & Average with a Coincident Peak Day Allocation Method

  The P&A method currently used by Centra for the allocation of transmission and distribution mains does not reflect proper cost causation principles. Transmission and distribution main investments are simply not a function of throughput, which is the "average" piece of the P&A method and can comprise as much as half of the demand-based allocation of transmission and distribution mains related plant. In actuality, transmission and distribution mains are a function of the cumulative peak day demands of those customers served by those pipeline infrastructure investments. Therefore, Atrium recommends the exclusive use of a Coincident Peak Day allocation of transmission mains and the demand component of distribution mains.

- Centra's Design Day Peak is the Preferred Method versus Actual Peak Days

  Atrium further recommends the use of Centra's design day peak demand as superior to using an actual peak day demand or an historical average of multiple peak day demands over time for purposes of deriving the allocation of demand-related costs of transmission and distribution pipeline facilities for the reasons enumerated in this report. Centra must consistently rely upon design day demand in the acquisition of its upstream gas supply-related capacity resources and in the design of its own transmission and distribution facilities required to service its firm service customers. Design day demand directly measures the maximum gas demand requirements of Centra's customers, which create the need for the to acquire resources, build facilities and incur fixed costs on an ongoing basis.

- Direct Assignment of Transmission Plant to the Special Contract Customer

  Atrium recommends a direct assignment of the transmission mains that serve the Special Contract customer's industrial facility, with no additional allocation of the broader transmission system. As discussed in our report, cost causation principles dictate that a customer or groups of customers that cause the utility to incur particular costs should be responsible for those costs. If a direct linkage between a utility's customers and the particular costs incurred by the utility in serving those customers is established, that cost is deemed a directly assignable cost. Atrium's

evaluation included a review of the Special Contract customer's contract terms; interrogatories and testimony from Centra's last rate proceeding; details of the special contract customer's service characteristics; physical location on the Centra transmission system; and other relevant information, which led us to reach this conclusion. Similar to the Special Contract customer, Atrium recommends that there be a direct assignment to the Power Station class for the pipeline facilities directly serving the Manitoba Hydro Power Station from the Brandon Primary Gate Station.

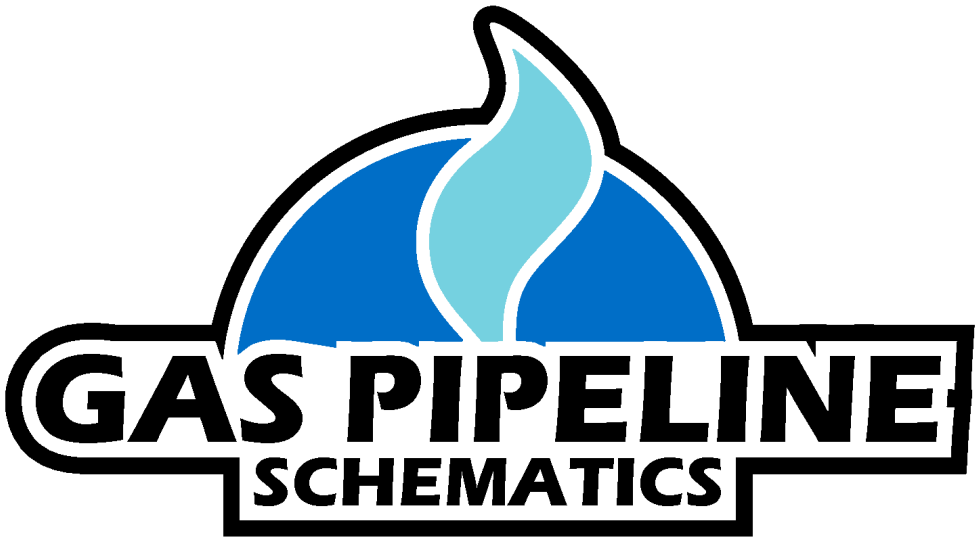
- Refresh the Development of the Customer Component of Distribution Mains

  Atrium recommends revisiting Centra's basis for the Customer component of distribution mains using either a zero intercept or minimum system method. The current method used by Centra to determine the customer component has not been revisited in many years. Atrium understands that Centra is currently conducting a depreciation study, after which the related plant accounting data should be organized in such a manner that will facilitate the performance of a new study to determine the customer component of its distribution mains.

- Consider an Alternative Approach to the Allocation of Upstream Capacity Resources

  Atrium recommends that Centra consider evaluating an alternative allocation approach to upstream contracted pipeline and storage capacity resources. We suggest a seasonal resource stack-based analysis of each pipeline and storage capacity resource's contribution to the seasonal and peak day demands of its customers. The analysis should include modeling the use of pipeline capacity for serving the seasonal customer demands vis-a-vis storage injections as well as peak day.

Appendix A. Gas Pipeline Schematics



Manitoba Hydro

Manitoba Hydro

Gas Pipeline System Flow & Control Schematics

The Flow and Control Schematics show information about pipeline systems required to understand how the gas is transported and identified points of controlling the gas flow. These schematics apply to transmission on high pressure systems only. The distribution piping systems that are supplied by these transmission and high pressure systems are not shown on the schematics.

These schematics contain only information appropriate to a schematic. EGIS should be consulted for full information.

Table of Contents

The hard copy (binder) set of Gas Pipeline Schematics is a **controlled document**.

It is supported by Distribution Standards and updates will be sent to all registered users.

For a hard copy (binder) of the Gas Pipeline Schematics contact Distribution Standards.

A PDF copy can be downloaded from the Distribution Standards Sharepoint Site.

Any errors, omissions, clarifications or additional detail required should be directed to Distribution Standards.

Rev. 02 2017 04 11

Manitoba Hydro

Supplementary Resources

The following is a list of supplementary resources for the Manitoba Hydro Gas Pipeline Schematics:

- Winnipeg Downtown Sectionalization Valve Book – Available through Safety Procedures and Standards\Gas Operating Procedures\Valve Books\Winnipeg Downtown Valve Book (Bucket truck icon)

- Winnipeg HP Segmentation Valve Book – Available through Safety Procedures and Standards\Gas Operating Procedures\Valve Books\Winnipeg HP Valve Book (Bucket truck icon)

- HP/TP Maps – Available in eGIS (Turn on HP/TP map objects in eGIS to view a proportional layout of all Manitoba Hydro HP and TP pressure class pipeline systems.

Manitoba Hydro

Town and Pipeline System Listing

This list presents selected Manitoba towns, the pipeline system from which they are served and the associated primary gate station.

This listing is not fully comprehensive. There may be some small towns that are not on this listing.

Town/City	Pipeline System	Primary Station(s)
Altona	South Loop	Oakville PGS / Dominion City PGS
Arborg	Winnipeg North	Ile Des Chenes PGS
Austin	Gladstone - Austin	North Norfold PGS
Beausejour	Winnipeg North	Ile Des Chenes PGS
Binscarth	Minell	McAuley PGS
Blumenort	Steinbach	Ste. Anne PGS
Boissevain	Brandon	Brandon PGS
Brandon	Brandon	Brandon PGS
Carberry	Carberry	Carberry PGS
Carman	South Loop	Oakville PGS / Dominion City PGS
Dauphin	Minell	McAuley PGS
Deloraine	Brandon	Brandon PGS
Dominion City	South Loop	Dominion City PGS
Dugald	Winnipeg	La Salle / Ile Des Chene / Oak Bluff
East Selkirk	Winnipeg	La Salle / Ile Des Chene / Oak Bluff
Elie	South Loop	Oakville PGS
Elkhorn	Virden	Miniota PGS
Elm Creek	South Loop	Oakville PGS / Dominion City PGS
Emerson	South Loop	Oakville PGS / Dominion City PGS
Garson	Winnipeg North	Ile Des Chenes PGS
Gilbert Plains	Minell	McAuley PGS
Gimli	Winnipeg North	Ile Des Chenes PGS
Gladstone	Gladstone - Austin	North Norfold PGS
Grandview	Minell	McAuley PGS
Gretna	South Loop	Oakville PGS / Dominion City PGS
Grunthal	St Pierre	St. Pierre PGS
Hamiota	Hamitota	Hamiota PGS
Hartney	Brandon	Brandon PGS
Ile Des Chene		Ile des Chenes PGS
Killarney	Brandon	Brandon PGS
La Broquerie	Steinbach	Ste. Anne PGS
La Salle	La Salle	La Salle PGS
Landmark		Landmark PGS
Letellier	South Loop	Oakville PGS / Dominion City PGS
Lockport	Winnipeg North	Ile Des Chenes PGS
Lorette	Lorette	Landmark PGS
Mac Gregor	MacGregor	MacGregor PGS
Melita	Brandon	Brandon PGS

Gas Pipeline System Flow & Control Schematics
Town and Pipeline System Listing

Town/City	Pipeline System	Primary Station(s)
Miniota	Virden	Miniota PGS
Minnedosa	Minnedosa - Shilo	Moore Park PGS
Minnedosa	Minnedosa (Ethanol Plant)	Brandon PGS
Morden	South Loop	Oakville PGS / Dominion City PGS
Morris	South Loop	Oakville PGS / Dominion City PGS
Neepawa	Neepawa	Neepawa PGS
New Bothwell	Niverville	Niverville PGS
Niverville	Niverville	Niverville PGS
Oakbank	Winnipeg	La Salle / Ile Des Chene / Oak Bluff
Oakville	South Loop	Oakville PGS / Dominion City PGS
Otterburne	St Pierre	St. Pierre PGS
Plum Coulee	South Loop	Oakville PGS / Dominion City PGS
Portage la Prairie	Portage la Prairie	Portage PGS
Rivers	Rivers	Rivers PGS
Riverton	Winnipeg North	Ile Des Chenes PGS
Roblin	Minell	McAuley PGS
Russell	Minell	McAuley PGS
Sanford	Sanford	Oak Bluff
Selkirk	Winnipeg North	Ile Des Chenes PGS
Shilo	Minnedosa - Shilo	Moore Park PGS
Shoal Lake	Hamitota	Hamiota PGS
Sidney	Gladstone - Austin	North Norfold PGS
Souris	Brandon	Brandon PGS
St Adolphe	St Adolphe	Ile des Chenes PGS
St Claude	Portage la Prairie	Portage PGS
St Jean Baptiste	South Loop	Oakville PGS / Dominion City PGS
St Lazare	Minell	McAuley PGS
St Joseph	South Loop	Oakville PGS / Dominion City PGS
St Malo	St. Malo	St. Malo PGS
St Pierre	St Pierre	St. Pierre PGS
St Pierre Jolys	South Loop	Oakville PGS / Dominion City PGS
Starbuck	Starbuck	Starbuck PGS
Ste Agathe	Ste Agathe	Ste. Agathe PGS
Ste Anne	Steinbach	Ste. Anne PGS
Steinbach	Steinbach	Ste. Anne PGS
Stonewall	Winnipeg North	Ile Des Chenes PGS
Swan Valley	Swan Valley	Benito PGS
Teulon	Winnipeg North	Ile Des Chenes PGS
Tyndall	Winnipeg North	Ile Des Chenes PGS
Virden	Virden	Miniota PGS
Warren	Winnipeg North	Ile Des Chenes PGS
Winkler	South Loop	Oakville PGS / Dominion City PGS
Winnipeg	Winnipeg	La Salle / Ile Des Chene / Oak Bluff / St Norbert

Rev 2 2014 05 02

Manitoba Hydro
Primary Gate Station Listing & TCPL Line Taps

Primary Station listing with identification of the TCPL line taps supplying the station

Number	Manitoba Hydro Primary Station Name	TCPL Primary Station Name	TCPL Line #					
			100-2	100-3	100-5	100-6	400-1	400-3
GS-100	McAuley	Moosomin			X	X		
GS-111	Virden/Miniota	Miniota			X	X		
GS-114	Hamiota	Hamiota			X	X		
GS-117	Rivers	Rivers-Wheatland			X	X		
GS-123	Brandon	Brandon			X	X		
GS-119	Moore Park	Shilo			X	X		
GS-121	Neepawa	Neepawa			X	X		
GS-127	Carberry	Carberry			X	X		
GS-195	Gladstone/Austin	Austin	X	X				
GS-130	MacGregor	MacGregor			X	X		
GS-193	Portage (Simplot)	Assiniboine			X	X		
GS-132	Portage	Portage La Prairie			X	X		
GS-136	Oakville	Carman	X	X				
GS-165	Starbuck	Starbuck			X	X		
GS-030	Oak Bluff	Oak Bluff			X	X		
GS-015	LaSalle	Winnipeg			X	X		
GS-002	St. Norbert	St. Norbert			X	X		
GS-017	Ile Des Chenes	Transcona			X	X		
GS-018	Landmark	Landmark and Selkirk	X	X				
GS-159	Ste Anne	Steinbach	X	X				
GS-177	Pineland	Hadashville	X	X				
GS-150	Niverville	Niverville					X	X
GS-180	St. Agathe	St. Agathe					X	X
GS-153	St.Pierre	St. Pierre					X	X
GS-167	St.Malo/Dufrost	St. Malo					X	X
GS-146	Dominion city	Altona					X	X

Line Taps to Systems Other Than TCPL:

Line Connected To	Manitoba Hydro's Pipeline System
MIPL (TranGas)	Swan Valley Pipeline System
EFG (Centra Gas Transmission)	RM of Piney (Sungro Perlite)

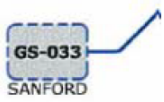
Rev 01 2017 04 10

Manitoba Hydro

Drawing Nomenclature and Conventions

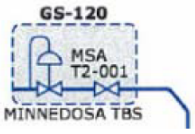
In addition to the Legend shown on the schematics, the nomenclature and drawing conventions adopted for the production of the Flow and Control Schematics are:

Gate stations shown as a rectangle will have an inlet isolation valve, an outlet isolation valve and a bypass valve.



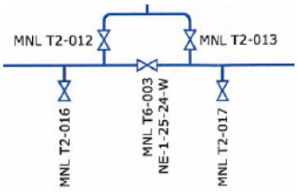
Gate stations with piping shown has necessary details added such as:

- A primary station that supplies more than one system where each system can be isolated will have the pipeline system isolation valves identified
- A station with a single valve and regulator denotes the absence of a second isolation valve and absence of a bypass
- A pressure control valve indicates pressure control equipment which may include multiple runs in a multiple cut and/or lead lag configuration and will also include regulator run isolation valves.



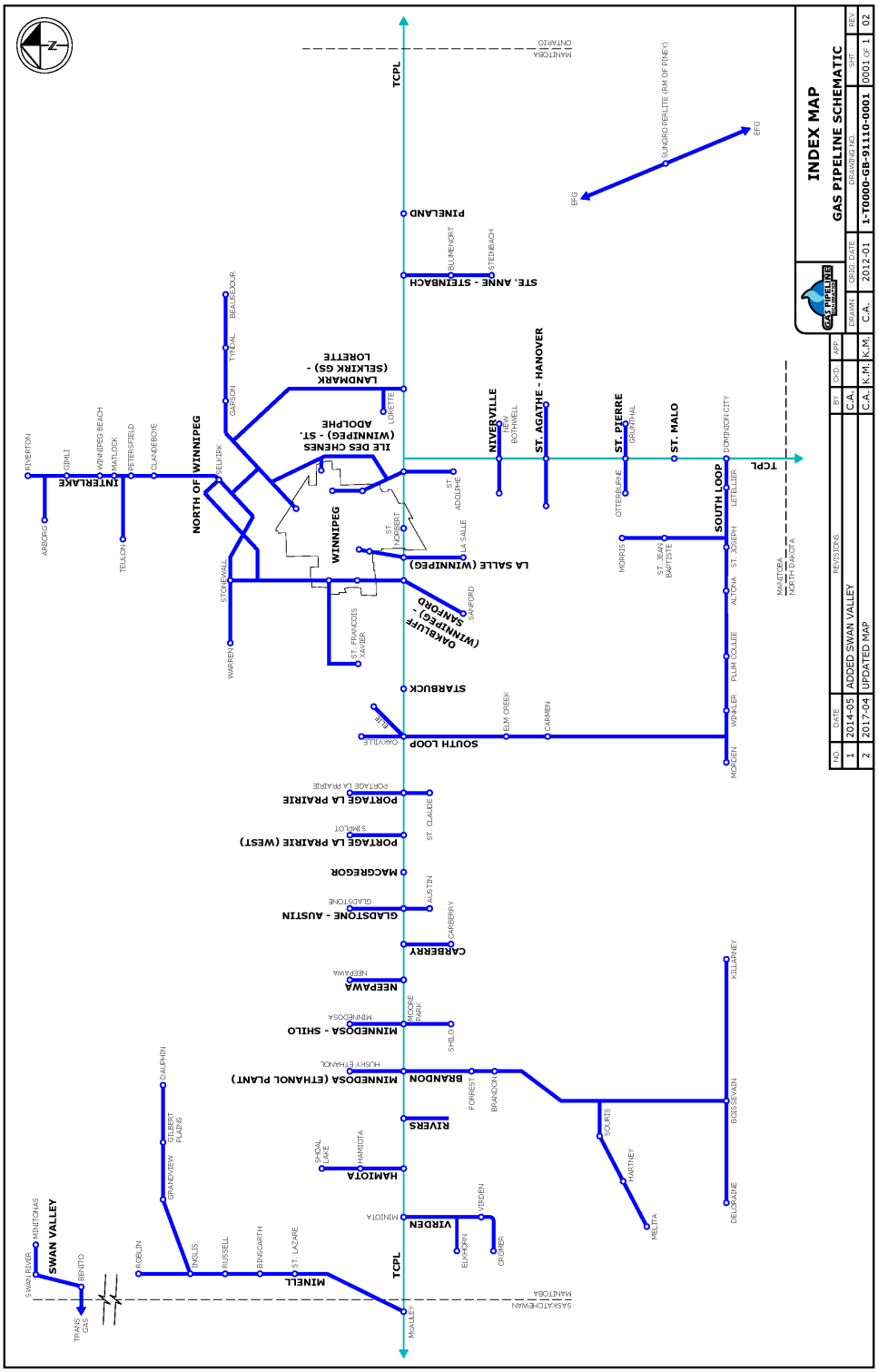
Some line stopping fittings are shown as "Stopple" and may be a spherical fitting. Not all line stop fittings on the pipelines are shown. For detailed information on line stop fittings, eGIS should be referenced. The condition of line stopping fittings, shown or not shown is unknown.

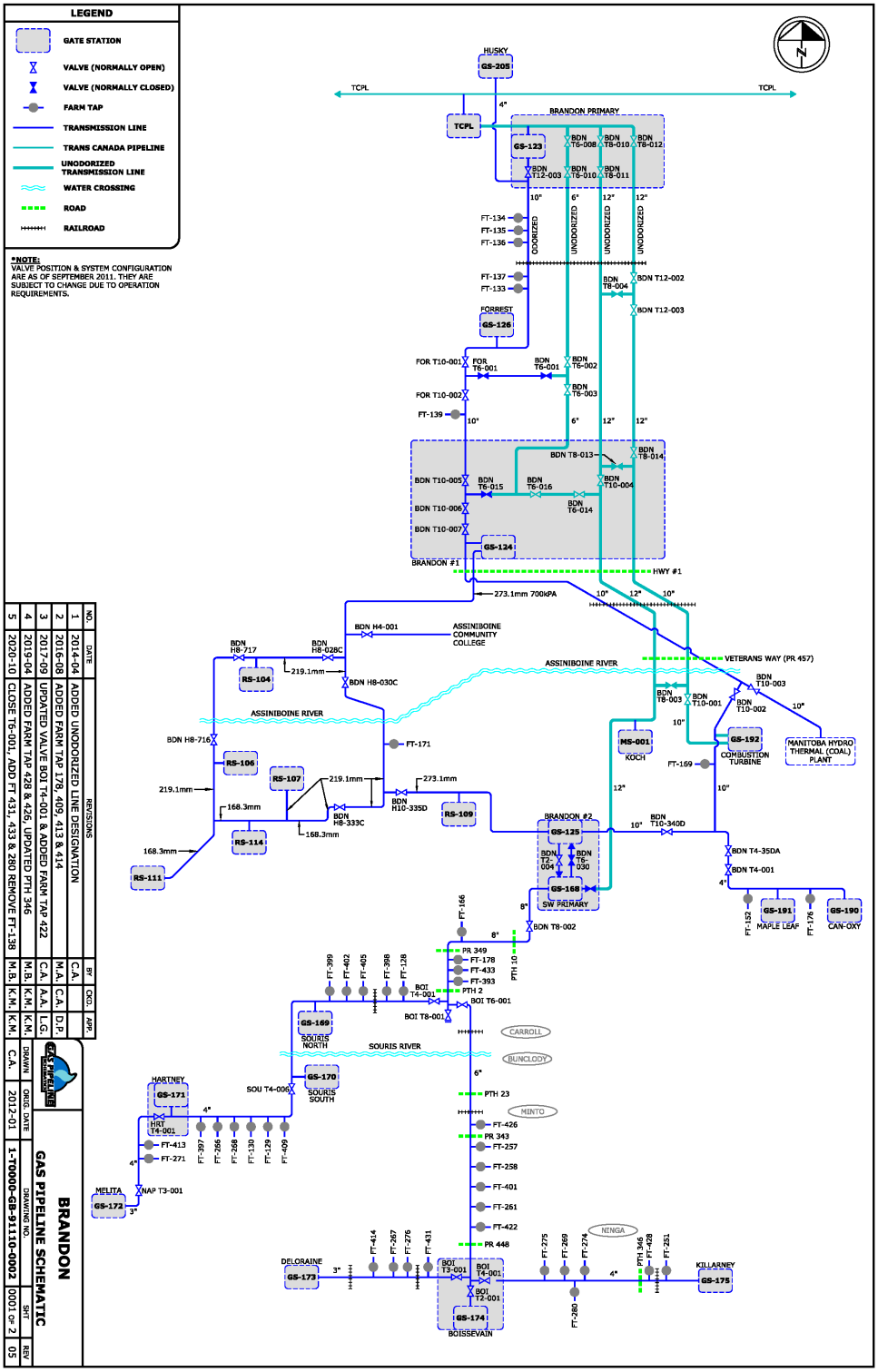
Line access valves may be shown where such information is available. Gate stations may or may not have line access (blowdown) valves.



While the schematics are true schematics and not to scale, they are generally drawn in a manner that represents the orientation of the pipeline system. Landmarks such as rivers, highways, etc. are shown to aid in a general geographic understanding of the pipeline system.

Rev. 01 2014 05 01





GATE STATION	DESCRIPTION
GS-123	BRANDON PRIMARY GATE STATION, NW-6-13-18-W, FROM PTH 1, NORTH 20.6km ON PTH 10 ON EAST SIDE OF ROAD
GS-124	BRANDON #1 GATE STATION, SW-6-11-18-W, NORTH PTH 1 SERVICE ROAD, 0.8km EAST OF PTH 10
GS-125	BRANDON #2 GATE STATION, SW-18-10-18-W, 17th ST E, 820m SOUTH OF VICTORIA, ON EAST SIDE OF ROAD
GS-126	FORREST GATE STATION, SW-31-11-18-W, FROM PTH 1, NORTH 8.4km ON PTH 10 ON EAST SIDE OF ROAD
GS-168	SOUTHWEST PRIMARY GATE STATION, SW-18-10-18-W, 17th ST E, 820m SOUTH OF VICTORIA, ON EAST SIDE OF ROAD, ON SAME SITE AS GS-125
GS-169	SOURIS NORTH GATE STATION, NE-34-7-21-W, PTH 2, 1.6km EAST OF PR 250 (1 ST N), SOUTH 75m ON SECTION ROAD, ON EAST SIDE OF ROAD
GS-170	SOURIS SOUTH GATE STATION, SW-34-7-21-W, PTH 22, 330m SOUTH OF BRINOLE AVE E, ON EAST SIDE OF ROAD
GS-171	HARTNEY GATE STATION, SW-22-6-23-W, FROM JCT OF E RAILWAY ST AND SECTION ROAD NORTH OF HARTNEY, 210m EAST, 40m NORTH, ON EAST SIDE OF ROAD
GS-172	MELITA GATE STATION, NE-6-4-26-W, PTH 83, 1.4km EAST OF MELITA, ON SOUTH SIDE OF E-W SECTION ROAD ADJACENT TO WIDE CURVE IN PTH 83
GS-173	DELORAINE GATE STATION, SW-11-3-23-W, N RAILWAY AVE, 170m EAST OF GOVERNMENT ROAD, ON NORTH SIDE
GS-174	BOISSEVAIN GATE STATION, NE-26-3-20-W, FROM PTH 10 & N RAILWAY ST, BOISSEVAIN, NORTH ON PTH 10, 1.5km TO WEST SERVICE ROAD (WILLIAM ST), ON WEST SIDE OF ROAD
GS-175	KILLARNEY GATE STATION, SW-11-3-17, LAKEVIEW AVE, 860m NORTH OF S RAILWAY ST, ON EAST SIDE OF ROAD
GS-190	BRANDON RICHMOND (CAN-OXY) GATE STATION, NE-10-10-18-W, RICHMOND AVE E, 2.9km EAST OF PTH 110, ON SOUTH SIDE OF ROAD
GS-191	BRANDON MAPLE LEAF GATE STATION, SE-16-10-18-W, RICHMOND AVE E, 1.1km EAST OF PTH 110, ON NORTH SIDE OF ROAD
GS-192	BRANDON COMBUSTION TURBINE GATE STATION, SW-20-10-18-W, 33rd ST E, 170m NORTH OF VICTORIA AVE, ON EAST SIDE OF ROAD
RS-104	KIRKCALDY DR RS, KIRKCALDY DR AT CONSERVATION DR, NORTH SIDE
RS-106	LOUISE AVE RS, LANE BETWEEN 20th & 21st ST, 50m N OF LOUISE AVE, EAST SIDE
RS-107	VICTORIA AVE RS, LANE BETWEEN 10th & 11th ST, 12m N OF VICTORIA, WEST SIDE
RS-109	PARK ST RS, PARK ST & VAN HORNE, SE CORNER
RS-111	34th ST RS, 34th ST & ELVISS CR SE CORNER, JUST NORTH OF CNR ALONG LANE
RS-114	KEYSTONE COMPLEX RS, 18th ST, 150m SOUTH OF PARK AVE, EAST SIDE, IN EXHIBITION GROUNDS

VALVE	DESCRIPTION
BDN T8-002	BRANDON, 17th ST E, 3.5km SOUTH OF PTH 110, ON EAST SIDE OF ROAD
BOI T4-001 BOI T8-001 BOI T6-001	NE-36-7-20-W, PR 348, 60m SOUTH OF PTH 2, ON THE WEST SIDE
BOI T4-001 BOI T3-001 BOI T2-001	AT BOISSEVAIN GATE STATION
SOU T4-006	AT SOURIS SOUTH GATE STATION
HRT T4-001	AT HARTNEY GATE STATION
NAP T3-001	NAPINKA, RAILWAY AVE, 420m EAST OF BROADWAY ST, ON SOUTH SIDE OF ROAD
BDN T12-003 BDN T8-010 BDN T8-011 BDN T8-012 BDN T6-008 BDN T6-010	AT GS-123, BRANDON PRIMARY GATE STATION
BDN T10-004 BDN T10-005 BDN T10-006 BDN T10-007 BDN T8-013 BDN T8-014 BDN T6-014 BDN T6-015 BDN T6-016	AT GS-124, BRANDON #1 GATE STATION
BDN T12-002 BDN T12-003 BDN T8-004	NW-6-12-18-W, PTH 10, NORTH 11.6km ON PTH 10, 650m EAST, ON NORTH SIDE OF ROAD
BDN T6-001 BDN T6-002 BDN T6-003	
FOR T10-001 FOR T6-001	SW-31-11-18-W, FROM PTH 1, NORTH 8.4km ON PTH 10 ON EAST SIDE OF ROAD (100m NORTH OF SECTION ROAD)
FOR T10-002	NW-30-11-18-W, FROM PTH 1, NORTH 8.3km ON PTH 10 ON EAST SIDE OF ROAD (SOUTH OF SECTION ROAD)
BDN T10-001 BDN T8-003	SE-19-10-18-W, 2505 VICTORIA AVE E & BRANDON SERVICE CENTRE DELIVERY ENTRANCE, 460m NORTH OF VICTORIA AVE E
BDN T10-002 BDN T10-003	SW-20-10-18-W, 510m NORTH OF VICTORIA AVE E, 150m EAST OF 33rd ST E, ON NORTH SIDE OF BRANDON COMBUSTION TURBINE SITE
BDN T10-340D	SW-18-10-18-W, 500m EAST OF GS-125, ON KOCH PROPERTY, ADJACENT TO MS-001
BDN T4-35DA BDN T4-001	SW-17-10-18-W, 33rd ST E, 830m SOUTH OF VICTORIA AVE E
BDN T6-030 BDN T2-004	AT BRANDON #2 GATE STATION
BDN H4-001	NORTH SIDE OF ASSINIBOINE COMMUNITY COLLEGE NORTH ENTRANCE BRANDON, 50m EAST OF 1st ST (40m NORTH OF KIRKHAM CR & 1st ST)
BDN H8-028C	1st ST & KIRKCALDY DR, NE SIDE
BDN H8-717	AT RS-104, KIRKCALDY DR AT CONSERVATION DR
BDN H8-716	MCDONALD AVE, 30m WEST OF 18th ST, NORTH SIDE
BDN H8-333C	VAN HORNE AVE, 70m WEST OF 1st ST, ON NORTH SIDE OF ROAD
BDN H10-335D	1st ST & VAN HORNE AVE, SE SIDE (NORTH OF TRACKS)
BDN H8-030C	1st ST, 310m NORTH OF ASSINIBOINE RIVER, ON EAST SIDE OF ROAD

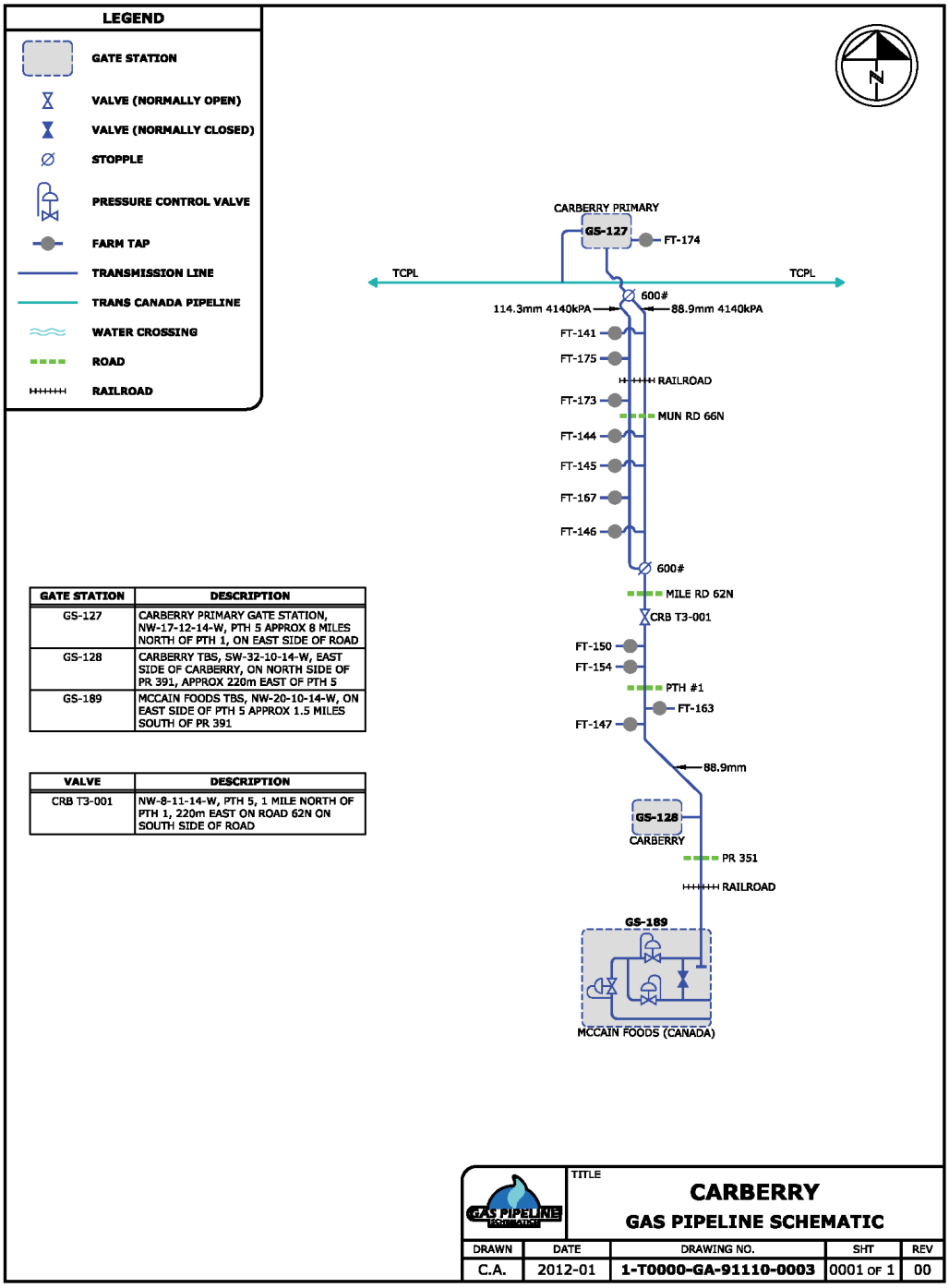
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	UPDATED VALVE BOI T10-001 TO BOI T4-001	C.A.	A.A.	L.G.

GAS PIPELINE SCHEMATIC

BRANDON

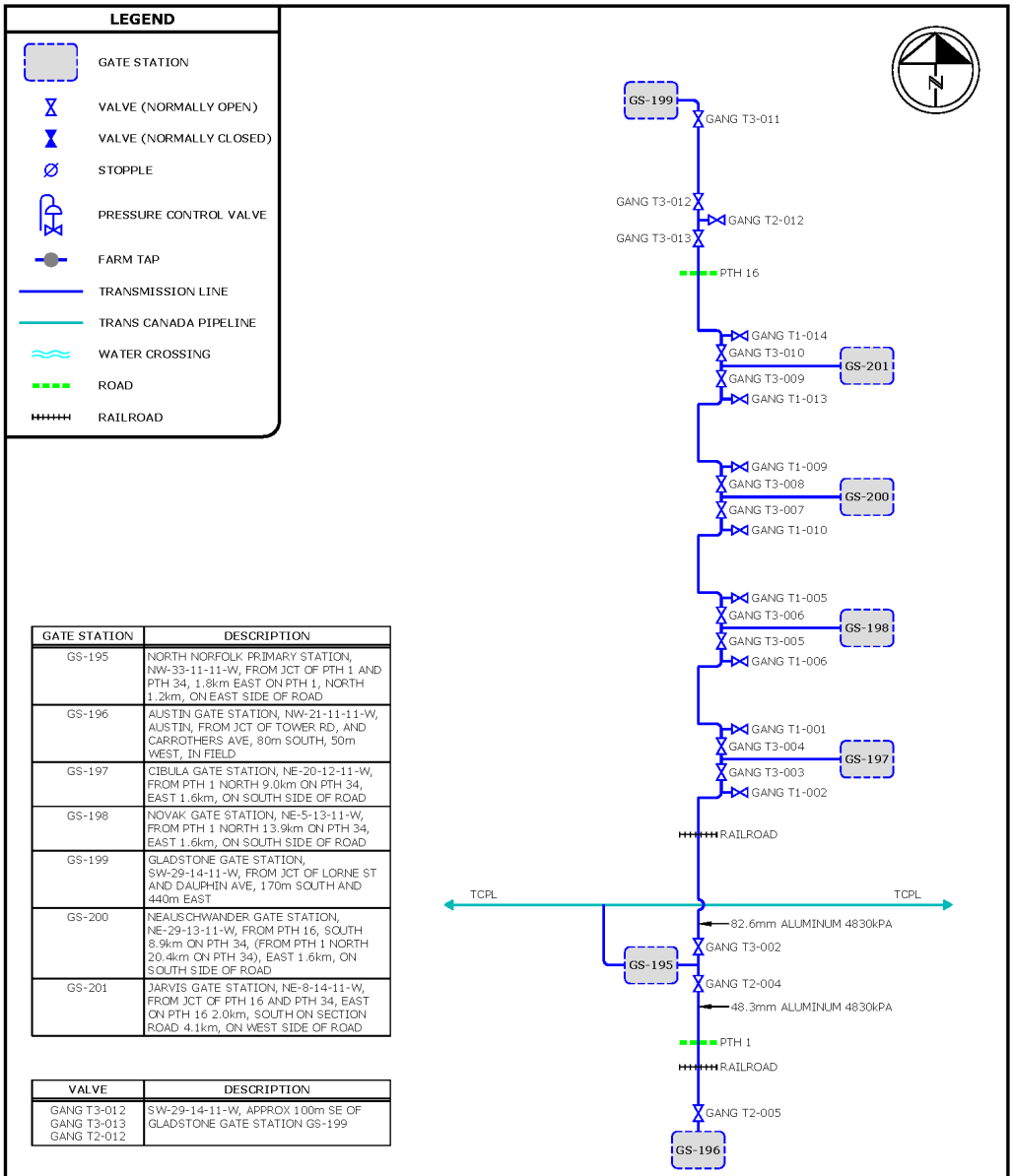
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	**1-T0000-GA-91110-0002**	0002 OF 2	01



GATE STATION	DESCRIPTION
GS-127	CARBERRY PRIMARY GATE STATION, NW-17-12-14-W, PTH 5 APPROX 8 MILES NORTH OF PTH 1, ON EAST SIDE OF ROAD
GS-128	CARBERRY TBS, SW-32-10-14-W, EAST SIDE OF CARBERRY, ON NORTH SIDE OF PR 391, APPROX 220m EAST OF PTH 5
GS-189	MCCAIN FOODS TBS, NW-20-10-14-W, ON EAST SIDE OF PTH 5 APPROX 1.5 MILES SOUTH OF PR 391

VALVE	DESCRIPTION
CRB T3-001	NW-8-11-14-W, PTH 5, 1 MILE NORTH OF PTH 1, 220m EAST ON ROAD 62N ON SOUTH SIDE OF ROAD

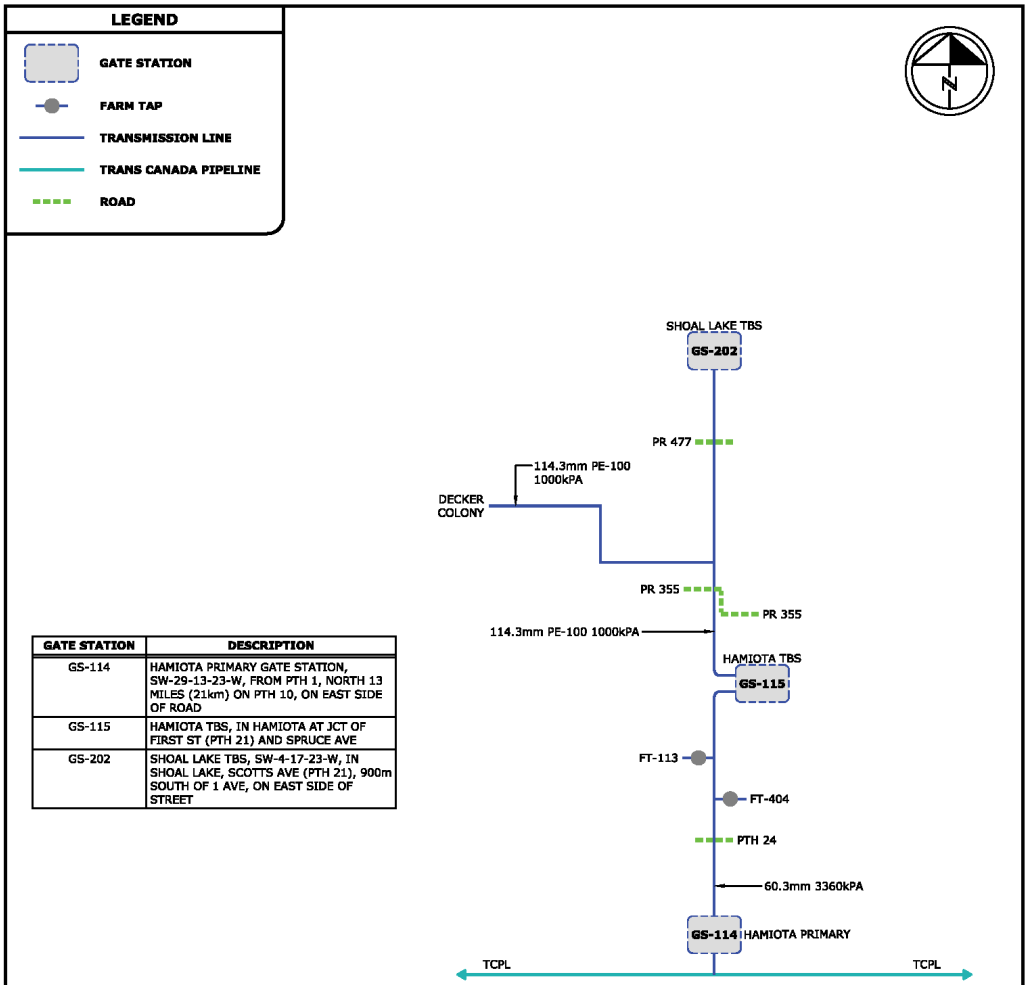


GATE STATION	DESCRIPTION
GS-195	NORTH NORFOLK PRIMARY STATION, NW-33-11-11-W, FROM JCT OF PTH 1 AND PTH 34, 1.8km EAST ON PTH 1, NORTH 1.2km, ON EAST SIDE OF ROAD
GS-196	AUSTIN GATE STATION, NW-21-11-11-W, AUSTIN, FROM JCT OF TOWER RD, AND CARROTHERS AVE, 80m SOUTH, 50m WEST, IN FIELD
GS-197	CIBULA GATE STATION, NE-20-12-11-W, FROM PTH 1 NORTH 9.0km ON PTH 34, EAST 1.6km, ON SOUTH SIDE OF ROAD
GS-198	NOVAK GATE STATION, NE-5-13-11-W, FROM PTH 1 NORTH 13.9km ON PTH 34, EAST 1.6km, ON SOUTH SIDE OF ROAD
GS-199	GLADSTONE GATE STATION, SW-29-14-11-W, FROM JCT OF LORNE ST AND DAUPHIN AVE, 170m SOUTH AND 440m EAST
GS-200	NEAUSCHWANDER GATE STATION, NE-29-13-11-W, FROM PTH 16, SOUTH 8.9km ON PTH 34, (FROM PTH 1 NORTH 20.4km ON PTH 34), EAST 1.6km, ON SOUTH SIDE OF ROAD
GS-201	JARVIS GATE STATION, NE-8-14-11-W, FROM JCT OF PTH 16 AND PTH 34, EAST ON PTH 16 2.0km, SOUTH ON SECTION ROAD 4.1km, ON WEST SIDE OF ROAD

VALVE	DESCRIPTION
GANG T3-012 GANG T3-013 GANG T2-012	SW-29-14-11-W, APPROX 100m SE OF GLADSTONE GATE STATION GS-199

TITLE
GLADSTONE - AUSTIN
GAS PIPELINE SCHEMATIC

NO.	DATE	REVISIONS	BY	CKD.	APP.	DRAWN	DATE	DRAWING NO.	SHT	REV
1	2016-08	UPDATED GAS TRANSMISSION	M.A.	C.A.	D.P.	C.A.	2012-01	**1-T0000-GA-91110-0004**	0001 OF 1	01



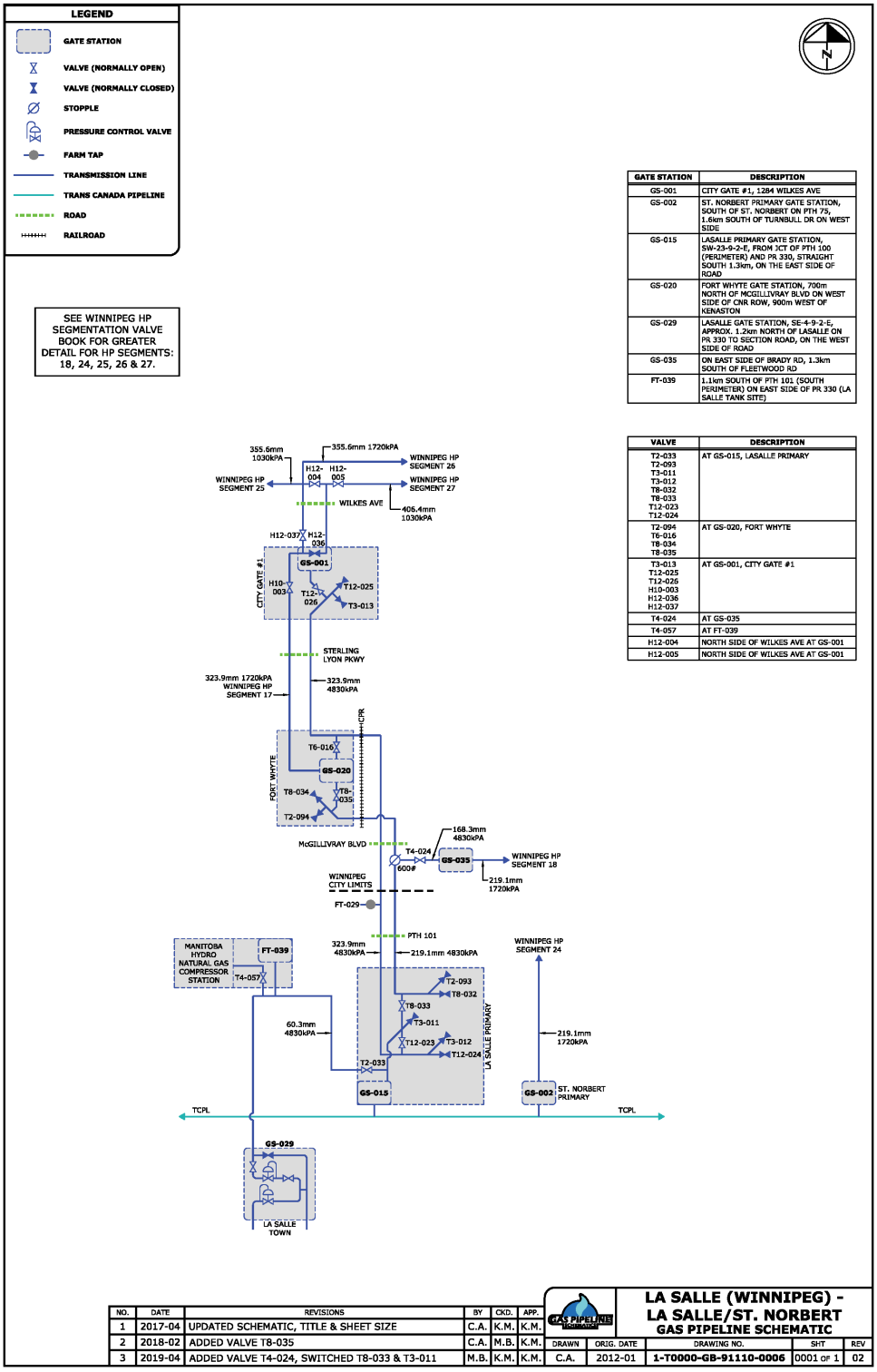
GATE STATION	DESCRIPTION
GS-114	HAMIOTA PRIMARY GATE STATION, SW-29-13-23-W, FROM PTH 1, NORTH 13 MILES (21km) ON PTH 10, ON EAST SIDE OF ROAD
GS-115	HAMIOTA TBS, IN HAMIOTA AT JCT OF FIRST ST (PTH 21) AND SPRUCE AVE
GS-202	SHOAL LAKE TBS, SW-4-17-23-W, IN SHOAL LAKE, SCOTTS AVE (PTH 21), 900m SOUTH OF 1 AVE, ON EAST SIDE OF STREET

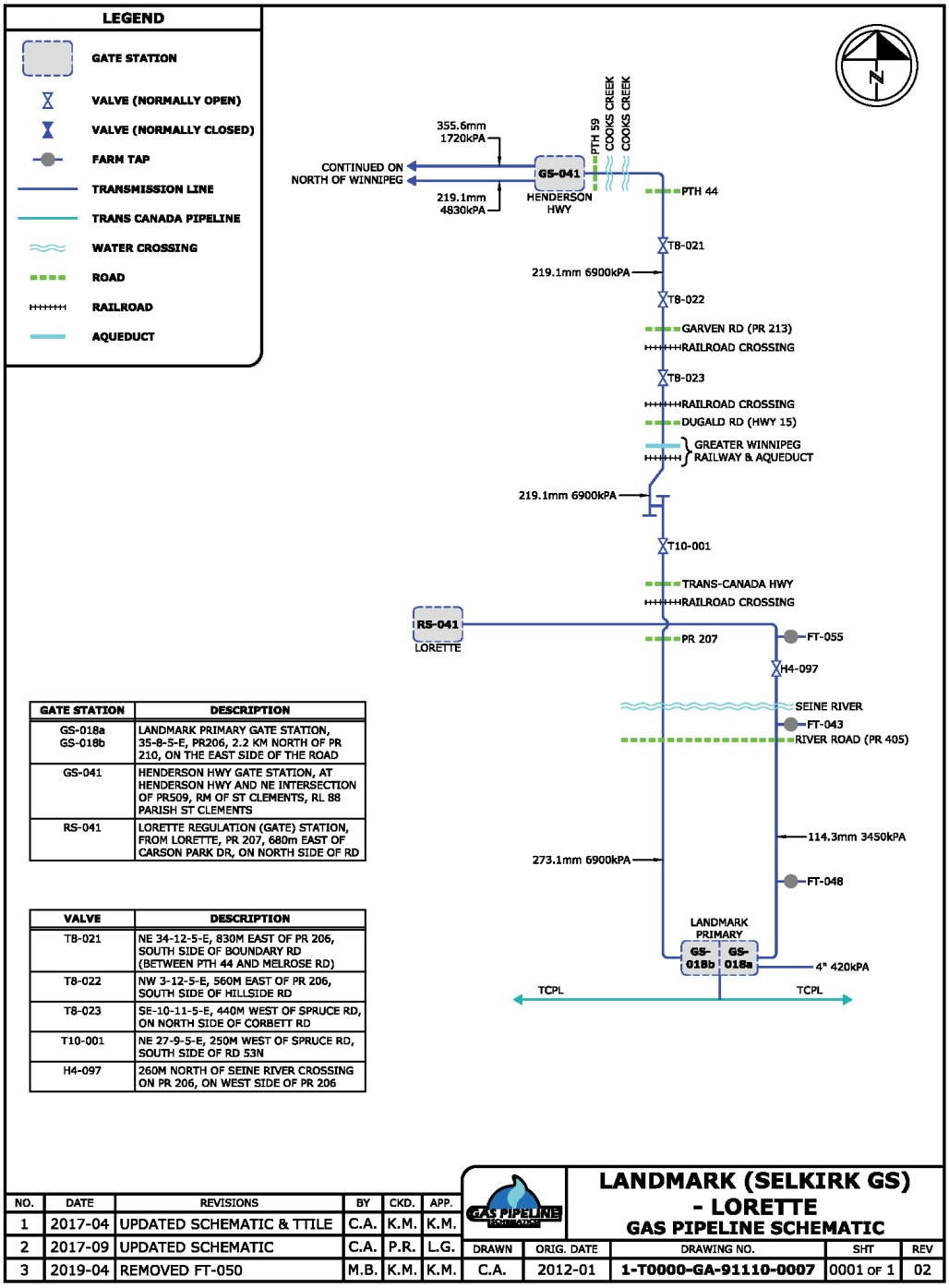
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	ADDED LINE TO DECKER COLONY	C.A.	A.A.	L.G.

GAS PIPELINE SCHEMATIC

HAMIOTA

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0005	0001 OF 1	01





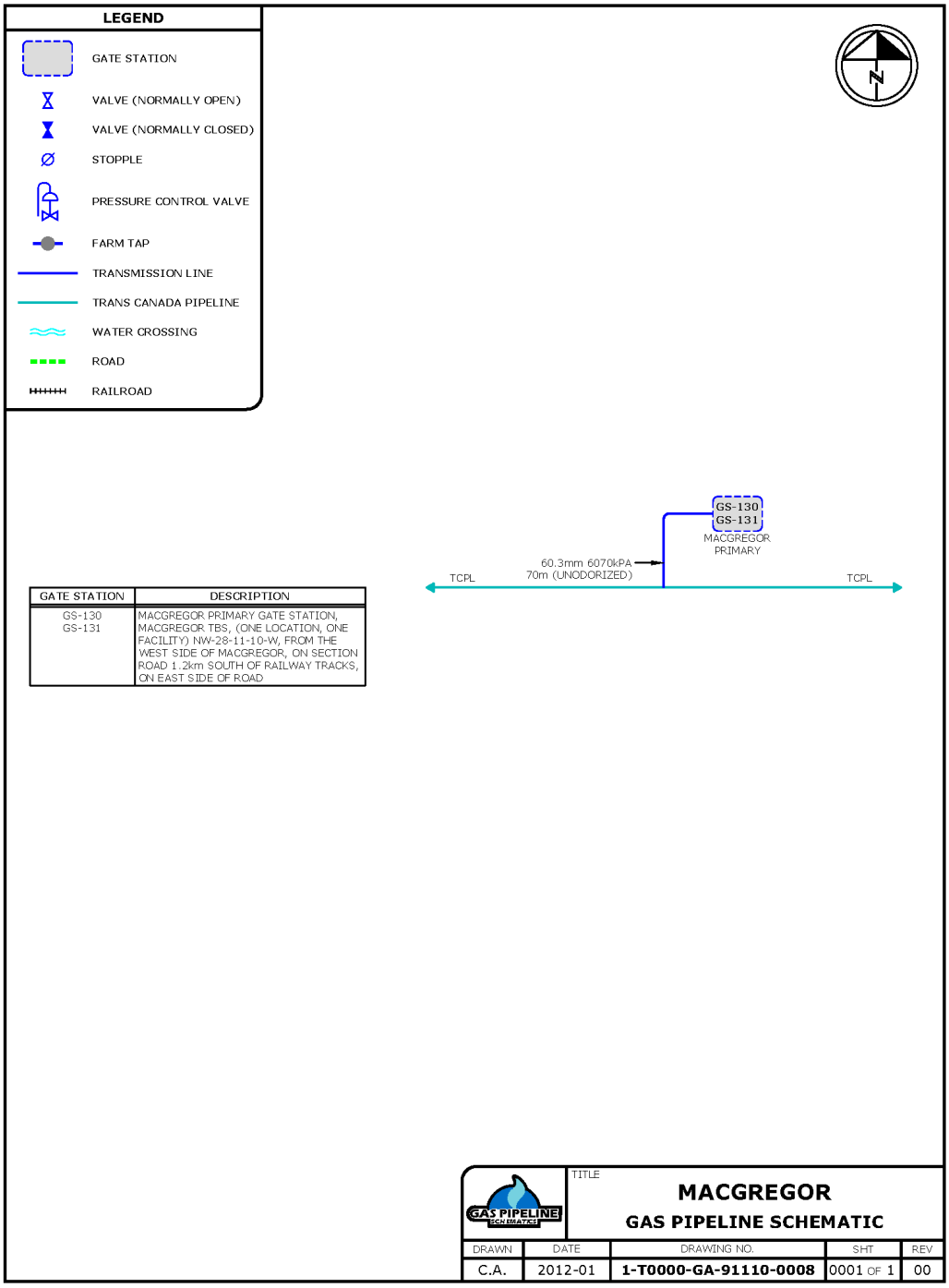
GATE STATION	DESCRIPTION
GS-018a GS-018b	LANDMARK PRIMARY GATE STATION, 35-8-5-E, PR206, 2.2 KM NORTH OF PR 210, ON THE EAST SIDE OF THE ROAD
GS-041	HENDERSON HWY GATE STATION, AT HENDERSON HWY AND NE INTERSECTION OF PR509, RM OF ST CLEMENTS, RL 88 PARISH ST CLEMENTS
RS-041	LORETTE REGULATION (GATE) STATION, FROM LORETTE, PR 207, 680m EAST OF CARSON PARK DR, ON NORTH SIDE OF RD

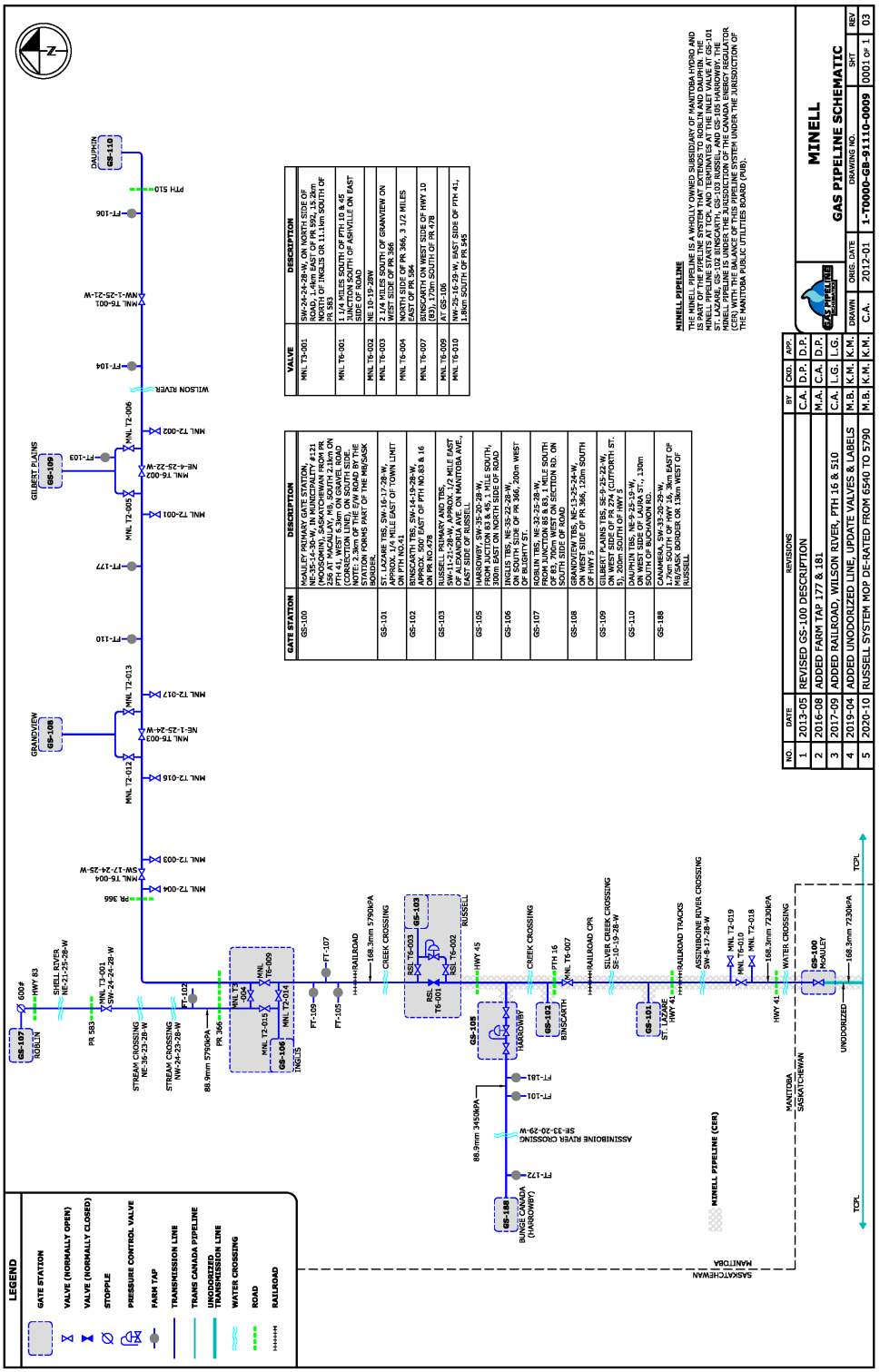
VALVE	DESCRIPTION
T8-021	NE 34-12-5-E, 830M EAST OF PR 206, SOUTH SIDE OF BOUNDARY RD (BETWEEN PTH 44 AND MELROSE RD)
T8-022	NW 3-12-5-E, 560M EAST OF PR 206, SOUTH SIDE OF HILLSIDE RD
T8-023	SE-10-11-5-E, 440M WEST OF SPRUCE RD, ON NORTH SIDE OF CORBETT RD
T10-001	NE 27-9-5-E, 250M WEST OF SPRUCE RD, SOUTH SIDE OF RD 53N
H4-097	260M NORTH OF SEINE RIVER CROSSING ON PR 206, ON WEST SIDE OF PR 206

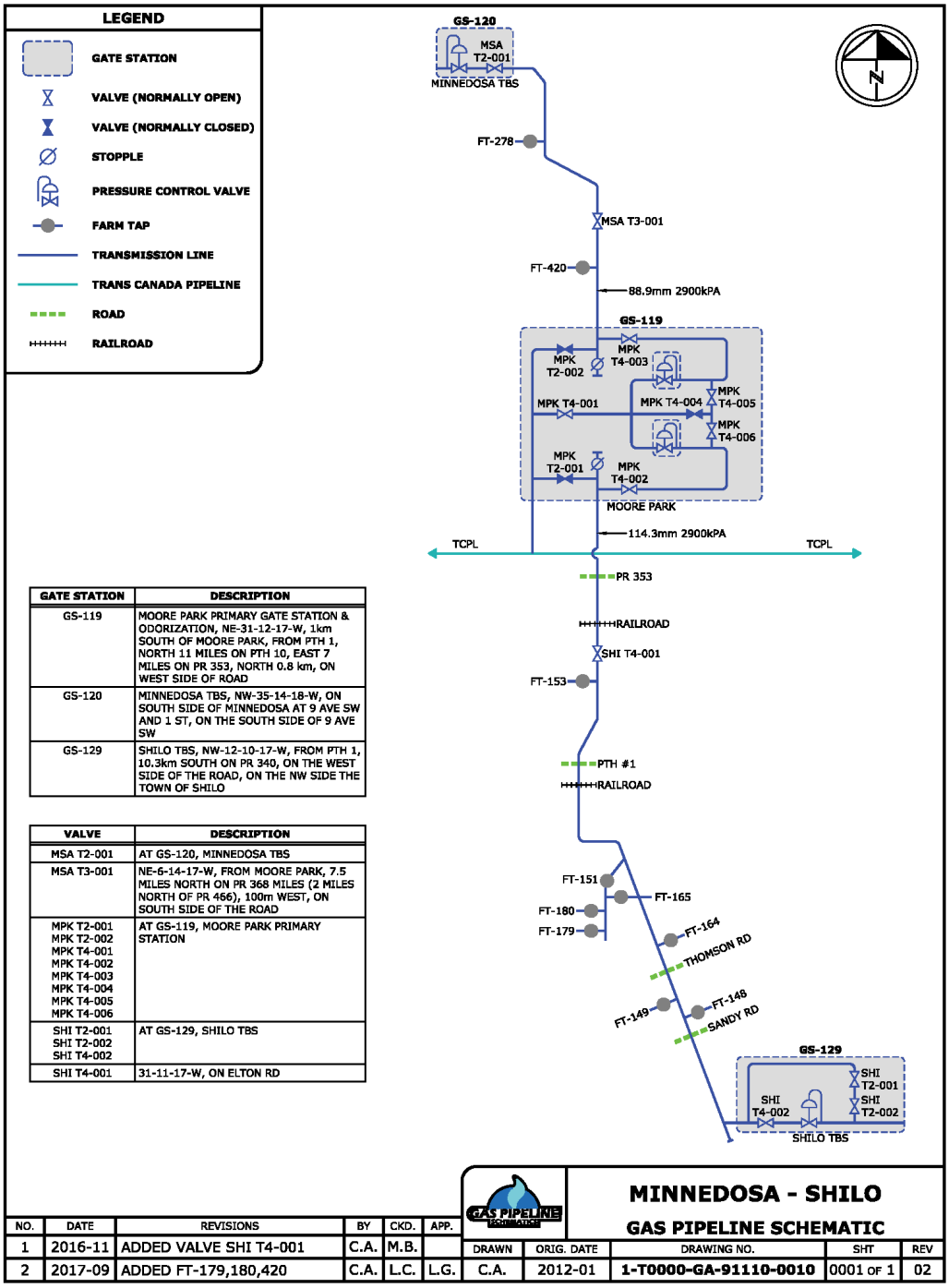
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-04	UPDATED SCHEMATIC & TTILE	C.A.	K.M.	K.M.
2	2017-09	UPDATED SCHEMATIC	C.A.	P.R.	L.G.
3	2019-04	REMOVED FT-050	M.B.	K.M.	K.M.

LANDMARK (SELKIRK GS) - LORETTE
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0007	0001 OF 1	02





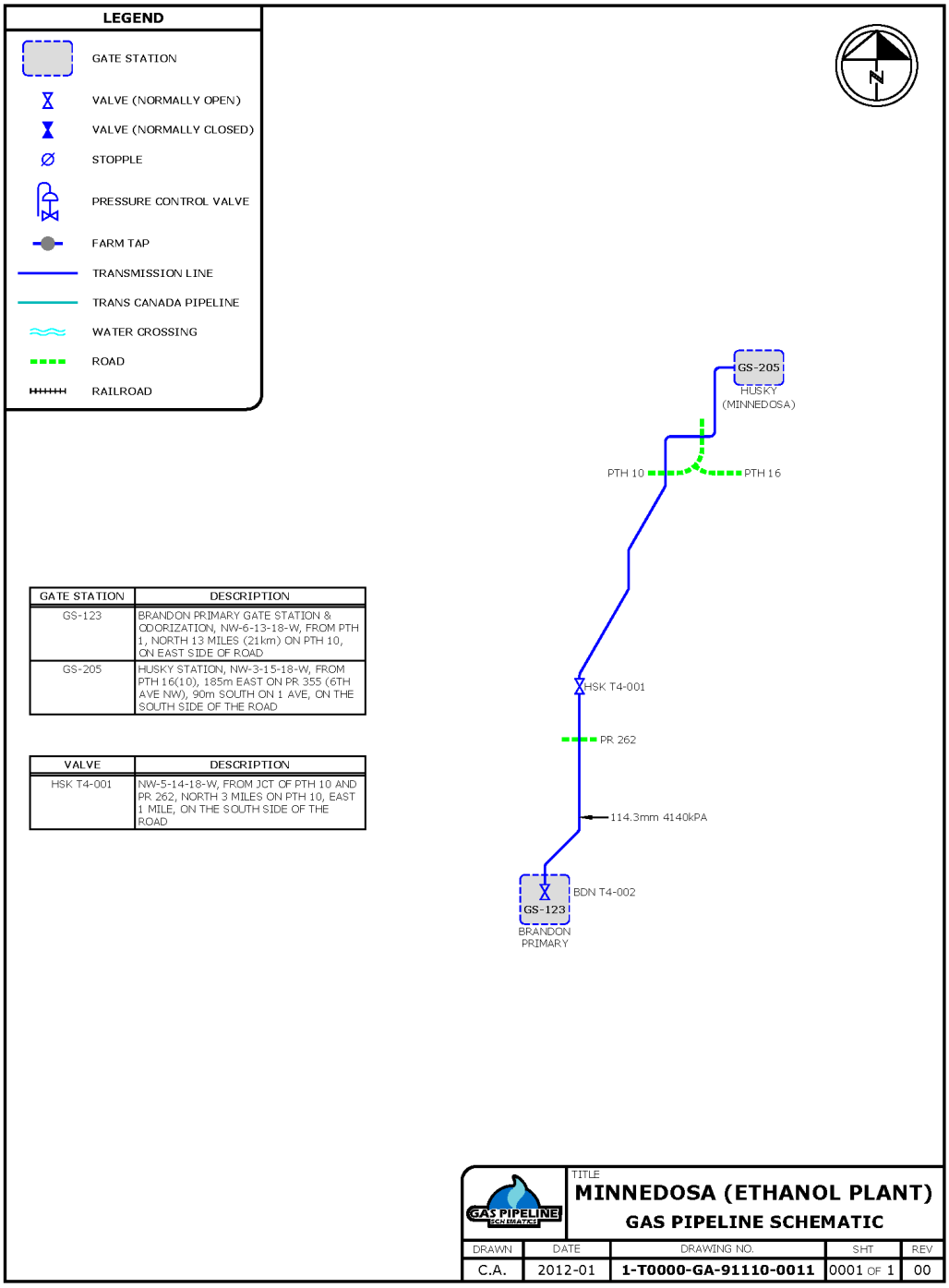


GATE STATION	DESCRIPTION
GS-119	MOORE PARK PRIMARY GATE STATION & ODORIZATION, NE-31-12-17-W, 1km SOUTH OF MOORE PARK, FROM PTH 1, NORTH 11 MILES ON PTH 10, EAST 7 MILES ON PR 353, NORTH 0.8 km, ON WEST SIDE OF ROAD
GS-120	MINNEDOSA TBS, NW-35-14-18-W, ON SOUTH SIDE OF MINNEDOSA AT 9 AVE SW AND 1 ST, ON THE SOUTH SIDE OF 9 AVE SW
GS-129	SHILO TBS, NW-12-10-17-W, FROM PTH 1, 10.3km SOUTH ON PR 340, ON THE WEST SIDE OF THE ROAD, ON THE NW SIDE THE TOWN OF SHILO

VALVE	DESCRIPTION
MSA T2-001	AT GS-120, MINNEDOSA TBS
MSA T3-001	NE-6-14-17-W, FROM MOORE PARK, 7.5 MILES NORTH ON PR 368 MILES (2 MILES NORTH OF PR 466), 100m WEST, ON SOUTH SIDE OF THE ROAD
MPK T2-001 MPK T2-002 MPK T4-001 MPK T4-002 MPK T4-003 MPK T4-004 MPK T4-005 MPK T4-006	AT GS-119, MOORE PARK PRIMARY STATION
SHI T2-001 SHI T2-002 SHI T4-002	AT GS-129, SHILO TBS
SHI T4-001	31-11-17-W, ON ELTON RD

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2016-11	ADDED VALVE SHI T4-001	C.A.	M.B.	
2	2017-09	ADDED FT-179,180,420	C.A.	L.C.	L.G.

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0010	0001 OF 1	02



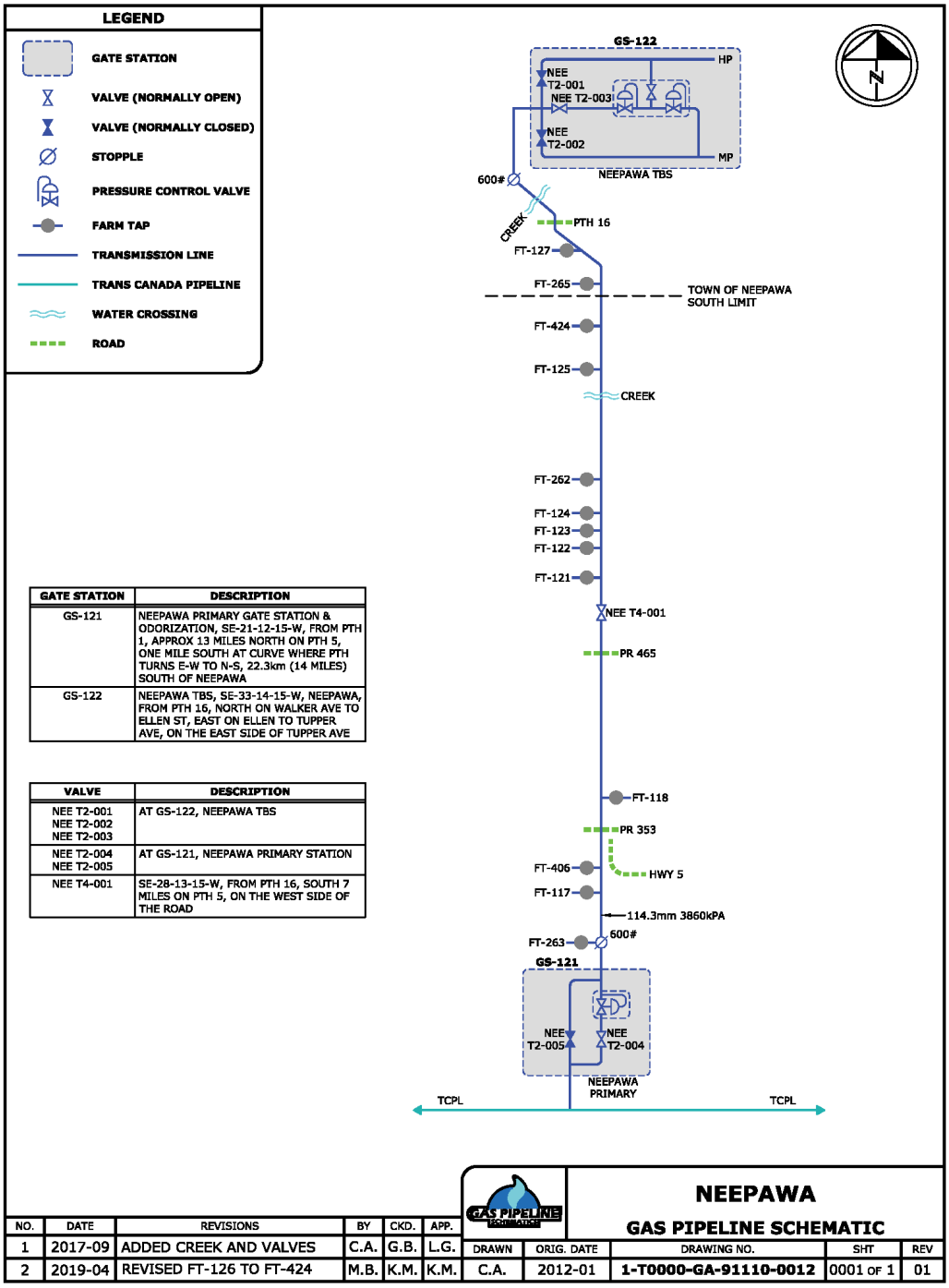
GATE STATION	DESCRIPTION
GS-123	BRANDON PRIMARY GATE STATION & ODORIZATION, NW-6-13-18-W, FROM PTH 1, NORTH 13 MILES (21km) ON PTH 10, ON EAST SIDE OF ROAD
GS-205	HUSKY STATION, NW-3-15-18-W, FROM PTH 16(10), 185m EAST ON PR 355 (6TH AVE NW), 90m SOUTH ON 1 AVE, ON THE SOUTH SIDE OF THE ROAD

VALVE	DESCRIPTION
HSK T4-001	NW-5-14-18-W, FROM JCT OF PTH 10 AND PR 262, NORTH 3 MILES ON PTH 10, EAST 1 MILE, ON THE SOUTH SIDE OF THE ROAD

GAS PIPELINE SCHEMATIC

TITLE
MINNEDOSA (ETHANOL PLANT)
GAS PIPELINE SCHEMATIC

DRAWN	DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	**1-T0000-GA-91110-0011**	0001 OF 1	00



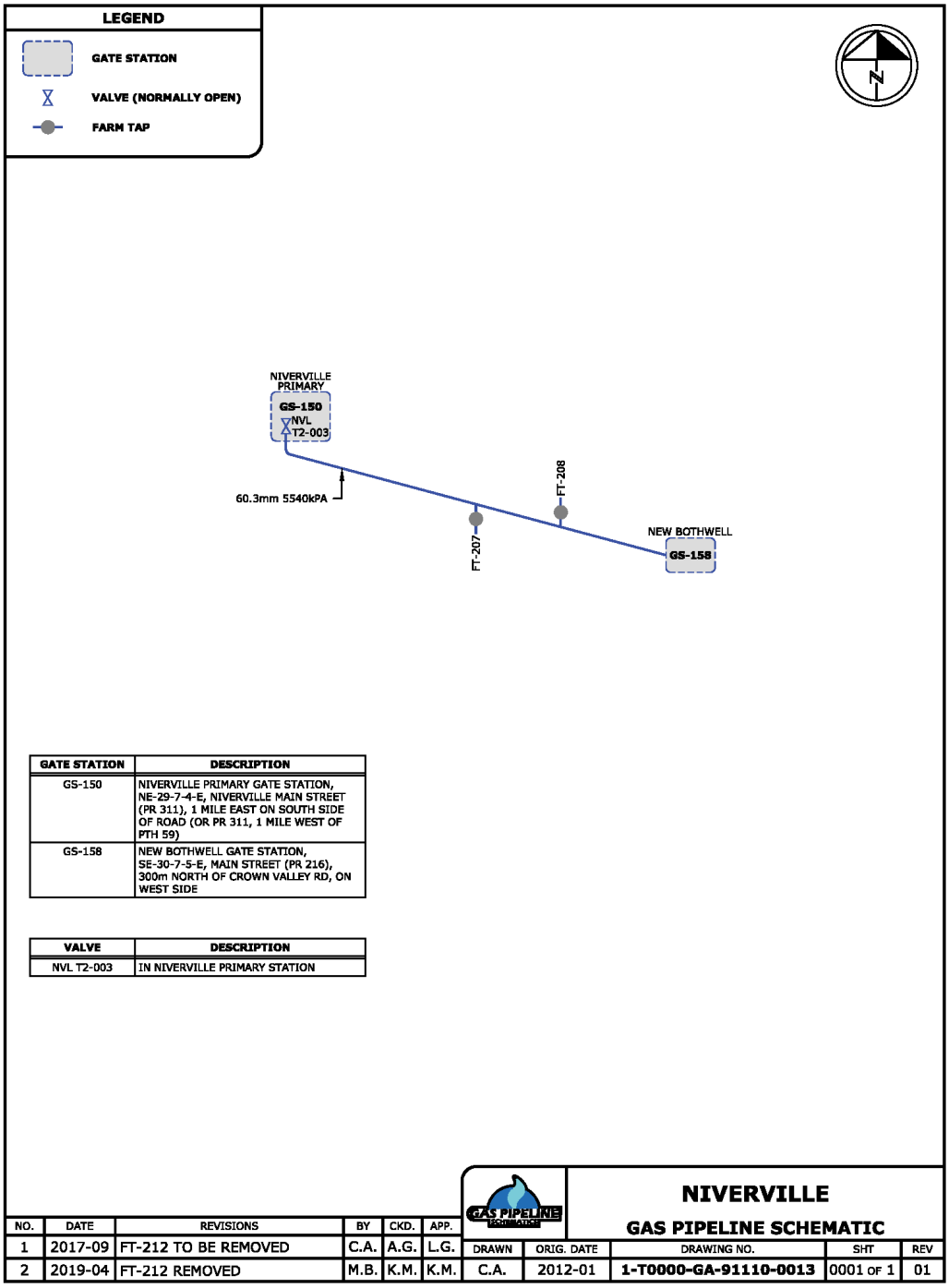
GATE STATION	DESCRIPTION
GS-121	NEEPAWA PRIMARY GATE STATION & ODORIZATION, SE-21-12-15-W, FROM PTH 1, APPROX 13 MILES NORTH ON PTH 5, ONE MILE SOUTH AT CURVE WHERE PTH TURNS E-W TO N-S, 22.3km (14 MILES) SOUTH OF NEEPAWA
GS-122	NEEPAWA TBS, SE-33-14-15-W, NEEPAWA, FROM PTH 16, NORTH ON WALKER AVE TO ELLEN ST, EAST ON ELLEN TO TUPPER AVE, ON THE EAST SIDE OF TUPPER AVE

VALVE	DESCRIPTION
NEE T2-001 NEE T2-002 NEE T2-003	AT GS-122, NEEPAWA TBS
NEE T2-004 NEE T2-005	AT GS-121, NEEPAWA PRIMARY STATION
NEE T4-001	SE-28-13-15-W, FROM PTH 16, SOUTH 7 MILES ON PTH 5, ON THE WEST SIDE OF THE ROAD

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	ADDED CREEK AND VALVES	C.A.	G.B.	L.G.
2	2019-04	REVISED FT-126 TO FT-424	M.B.	K.M.	K.M.

NEEPAWA
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0012	0001 OF 1	01



GATE STATION	DESCRIPTION
GS-150	NIVERVILLE PRIMARY GATE STATION, NE-29-7-4-E, NIVERVILLE MAIN STREET (PR 311), 1 MILE EAST ON SOUTH SIDE OF ROAD (OR PR 311, 1 MILE WEST OF PTH 59)
GS-158	NEW BOTHWELL GATE STATION, SE-30-7-5-E, MAIN STREET (PR 216), 300m NORTH OF CROWN VALLEY RD, ON WEST SIDE

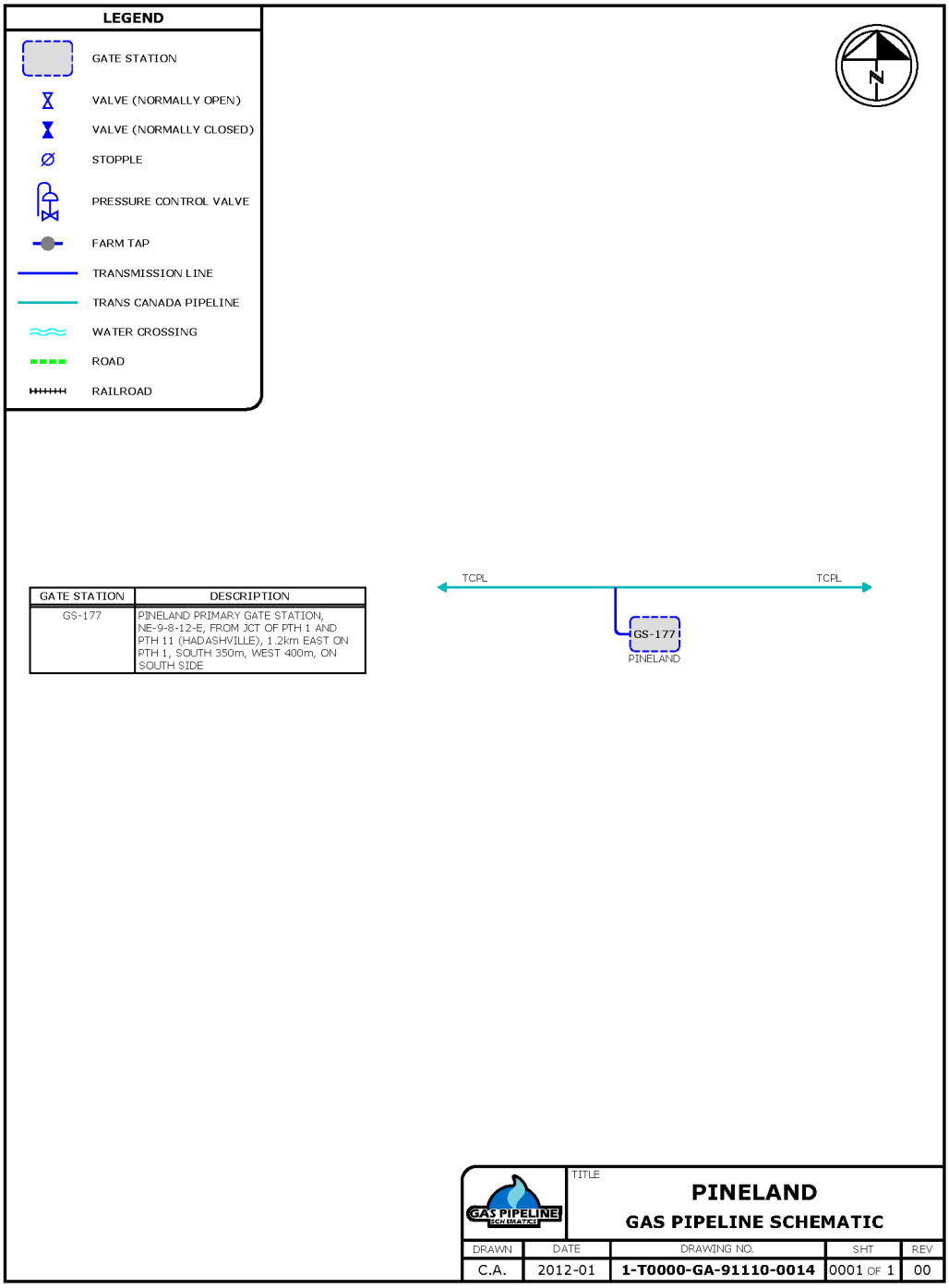
VALVE	DESCRIPTION
NVL T2-003	IN NIVERVILLE PRIMARY STATION

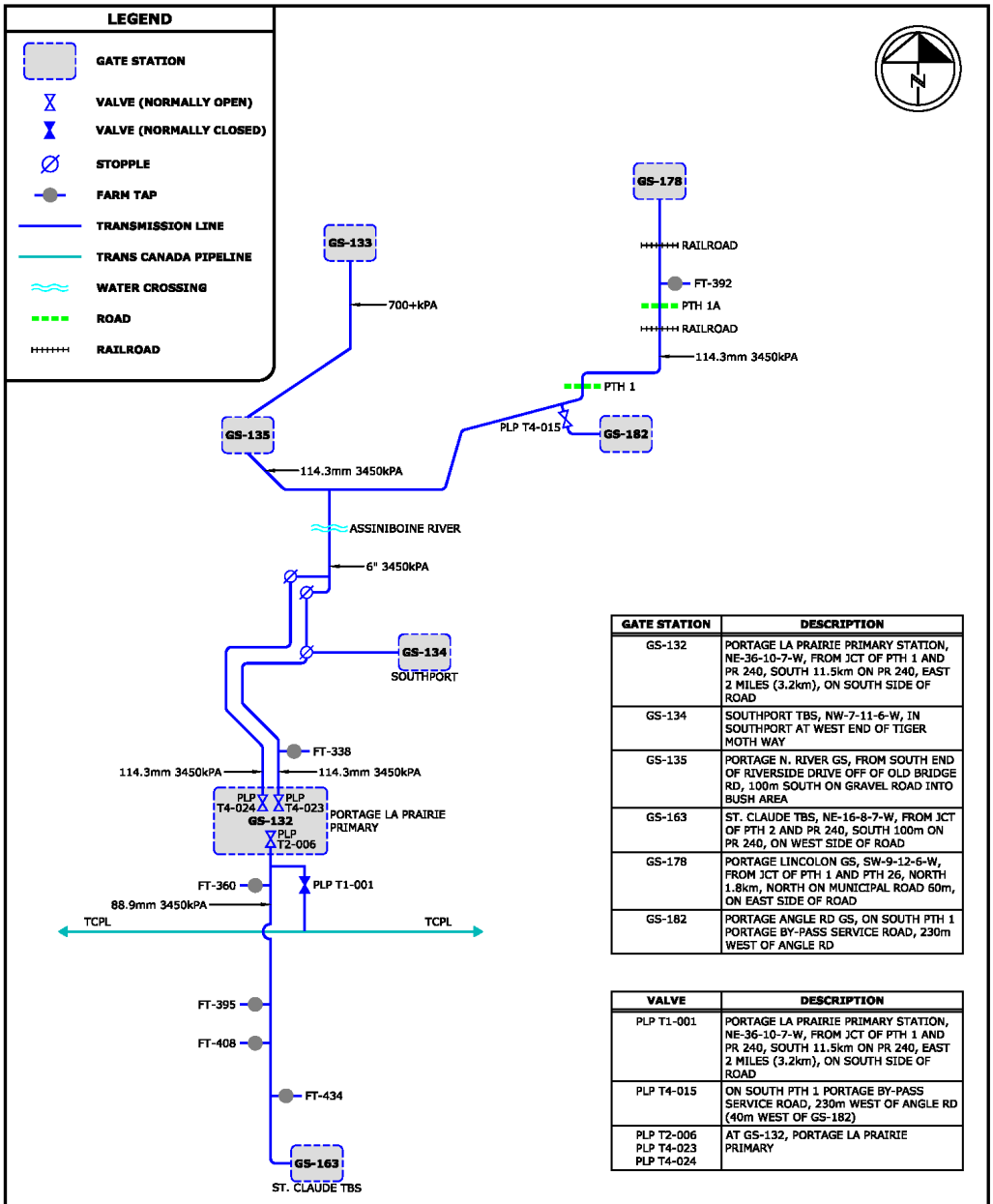
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	FT-212 TO BE REMOVED	C.A.	A.G.	L.G.
2	2019-04	FT-212 REMOVED	M.B.	K.M.	K.M.

GAS PIPELINE

NIVERVILLE
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0013	0001 OF 1	01





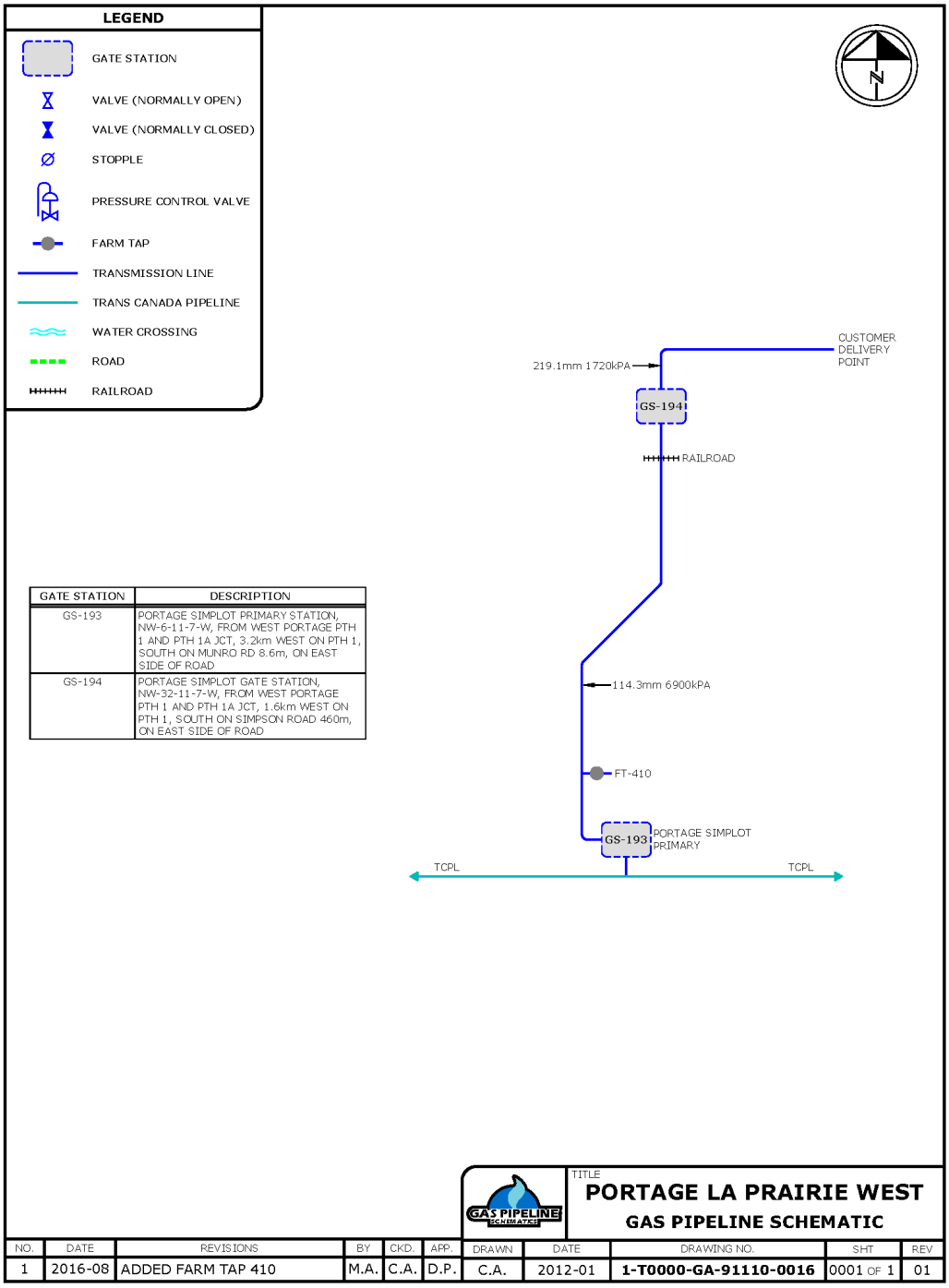
GATE STATION	DESCRIPTION
GS-132	PORTAGE LA PRAIRIE PRIMARY STATION, NE-36-10-7-W, FROM JCT OF PTH 1 AND PR 240, SOUTH 11.5km ON PR 240, EAST 2 MILES (3.2km), ON SOUTH SIDE OF ROAD
GS-134	SOUTHPORT TBS, NW-7-11-6-W, IN SOUTHPORT AT WEST END OF TIGER MOTH WAY
GS-135	PORTAGE N. RIVER GS, FROM SOUTH END OF RIVERSIDE DRIVE OFF OF OLD BRIDGE RD, 100m SOUTH ON GRAVEL ROAD INTO BUSH AREA
GS-163	ST. CLAUDE TBS, NE-16-8-7-W, FROM JCT OF PTH 2 AND PR 240, SOUTH 100m ON PR 240, ON WEST SIDE OF ROAD
GS-178	PORTAGE LINCOLON GS, SW-9-12-6-W, FROM JCT OF PTH 1 AND PTH 26, NORTH 1.8km, NORTH ON MUNICIPAL ROAD 60m, ON EAST SIDE OF ROAD
GS-182	PORTAGE ANGLE RD GS, ON SOUTH PTH 1 PORTAGE BY-PASS SERVICE ROAD, 230m WEST OF ANGLE RD

VALVE	DESCRIPTION
PLP T1-001	PORTAGE LA PRAIRIE PRIMARY STATION, NE-36-10-7-W, FROM JCT OF PTH 1 AND PR 240, SOUTH 11.5km ON PR 240, EAST 2 MILES (3.2km), ON SOUTH SIDE OF ROAD
PLP T4-015	ON SOUTH PTH 1 PORTAGE BY-PASS SERVICE ROAD, 230m WEST OF ANGLE RD (40m WEST OF GS-182)
PLP T2-006 PLP T4-023 PLP T4-024	AT GS-132, PORTAGE LA PRAIRIE PRIMARY

NO.	DATE	REVISIONS	BY	CKD.	APP.
2	2017-09	ADDED GS-133 & FT-377, ABANDONED FT-390,378,377	C.A.	A.A.	L,.G.
3	2019-04	ADDED PLP T1-001, ABANDONED FT-341 & 377	M.B.	K.M.	K.M.
4	2020-10	ADDED FT-434	M.B.	K.M.	K.M.

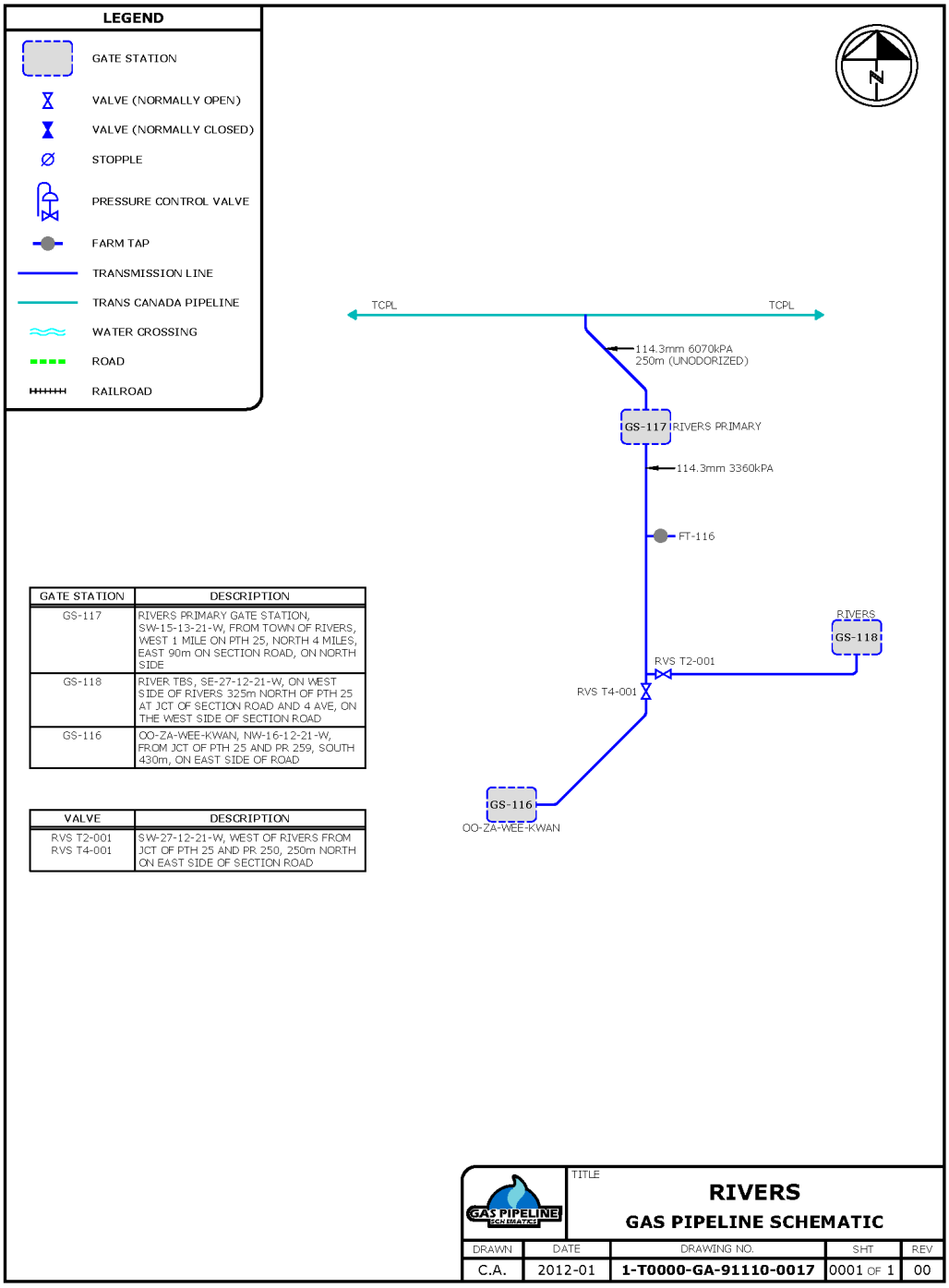
PORTAGE LA PRAIRIE
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0015	0001 OF 1	04



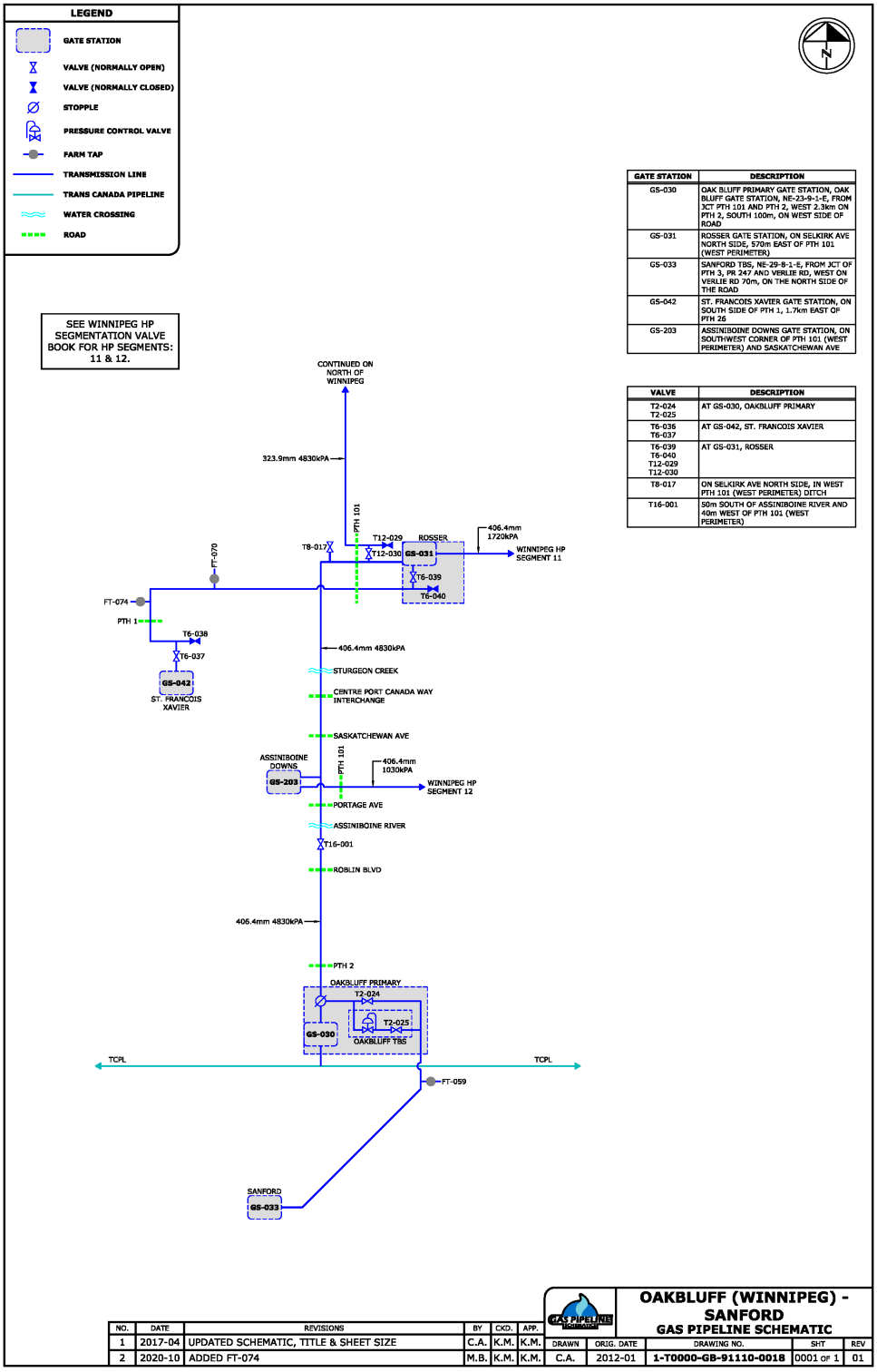
GATE STATION	DESCRIPTION
GS-193	PORTAGE SIMPLOT PRIMARY STATION, NW-6-11-7-W, FROM WEST PORTAGE PTH 1 AND PTH 1A JCT, 3.2km WEST ON PTH 1, SOUTH ON MUNRO RD 8.6m, ON EAST SIDE OF ROAD
GS-194	PORTAGE SIMPLOT GATE STATION, NW-32-11-7-W, FROM WEST PORTAGE PTH 1 AND PTH 1A JCT, 1.6km WEST ON PTH 1, SOUTH ON SIMPSON ROAD 460m, ON EAST SIDE OF ROAD

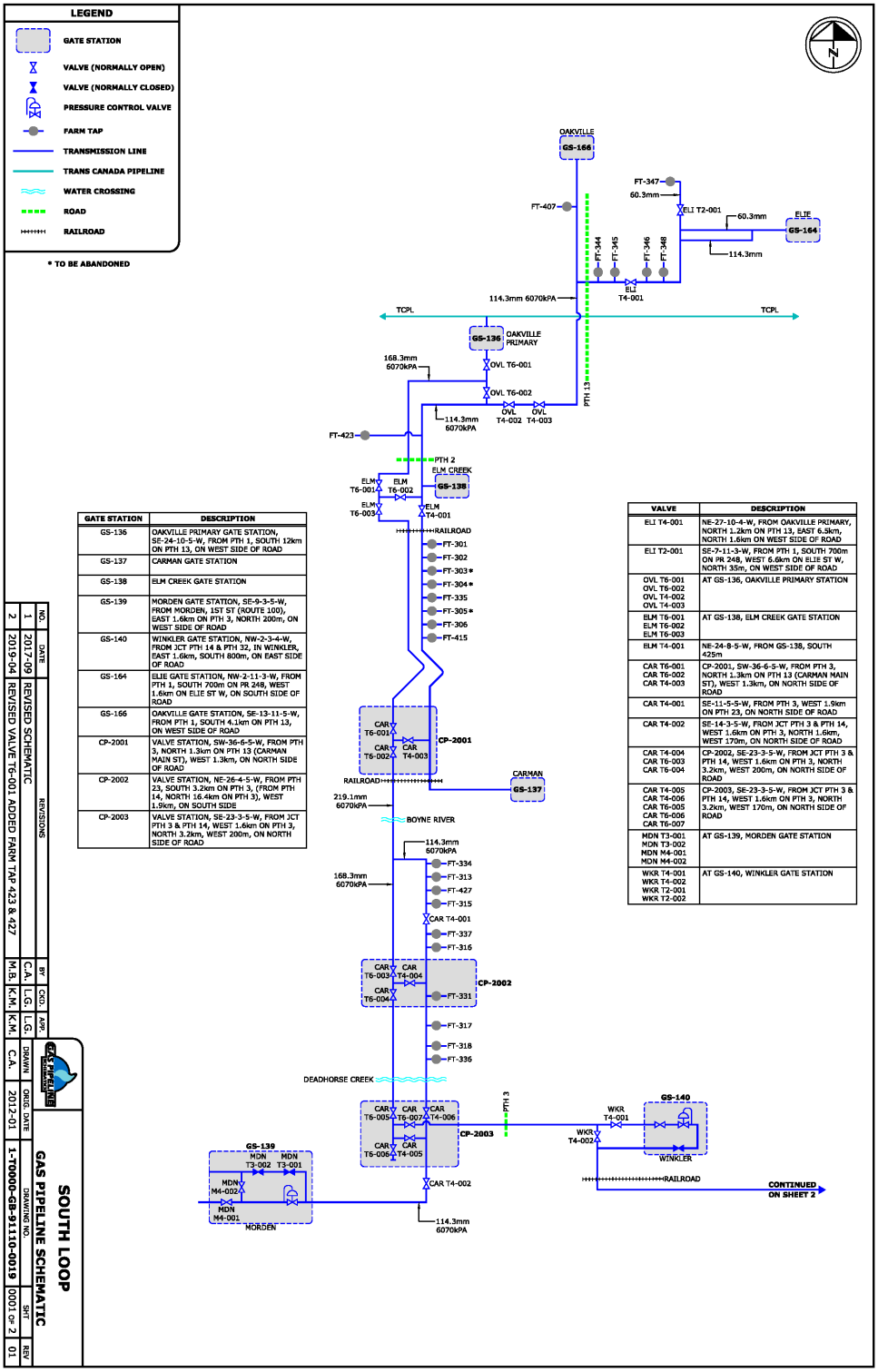
NO.	DATE	REVISIONS	BY	CKD.	APP.	DRAWN	DATE	DRAWING NO.	SHT	REV
1	2016-08	ADDED FARM TAP 410	M.A.	C.A.	D.P.	C.A.	2012-01	**1-T0000-GA-91110-0016**	0001 OF 1	01



GATE STATION	DESCRIPTION
GS-117	RIVERS PRIMARY GATE STATION, SW-15-13-21-W, FROM TOWN OF RIVERS, WEST 1 MILE ON PTH 25, NORTH 4 MILES, EAST 90m ON SECTION ROAD, ON NORTH SIDE
GS-118	RIVER TBS, SE-27-12-21-W, ON WEST SIDE OF RIVERS 325m NORTH OF PTH 25 AT JCT OF SECTION ROAD AND 4 AVE, ON THE WEST SIDE OF SECTION ROAD
GS-116	OO-ZA-WEE-KWAN, NW-16-12-21-W, FROM JCT OF PTH 25 AND PR 259, SOUTH 430m, ON EAST SIDE OF ROAD

VALVE	DESCRIPTION
RVS T2-001 RVS T4-001	SW-27-12-21-W, WEST OF RIVERS FROM JCT OF PTH 25 AND PR 250, 250m NORTH ON EAST SIDE OF SECTION ROAD





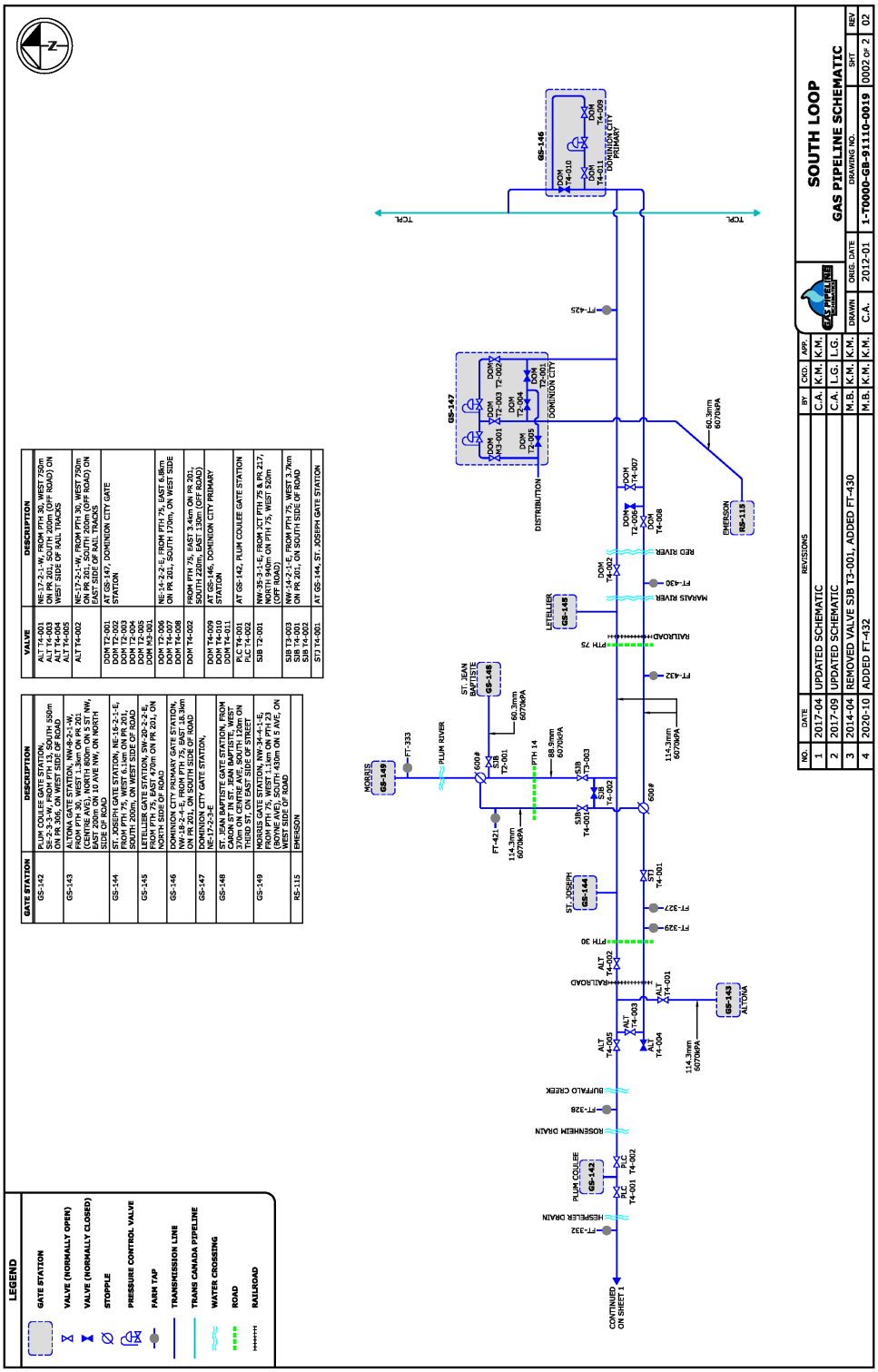
GATE STATION	DESCRIPTION
GS-136	OAKVILLE PRIMARY GATE STATION, SE-24-10-5-W, FROM PTH 1, SOUTH 12km ON PTH 13, ON WEST SIDE OF ROAD
GS-137	CARMAN GATE STATION
GS-138	ELM CREEK GATE STATION
GS-139	MORDEN GATE STATION, SE-9-3-5-W, FROM MORDEN, 1ST ST (ROUTE 100), EAST 1.6km ON PTH 3, NORTH 200m, ON WEST SIDE OF ROAD
GS-140	WINKLER GATE STATION, NW-2-3-4-W, FROM JCT PTH 14 & PTH 32, IN WINKLER, EAST 1.6km, SOUTH 800m, ON EAST SIDE OF ROAD
GS-164	ELIE GATE STATION, NW-2-11-3-W, FROM PTH 1, SOUTH 700m ON PR 248, WEST 1.6km ON ELIE ST W, ON SOUTH SIDE OF ROAD
GS-166	OAKVILLE GATE STATION, SE-13-11-5-W, FROM PTH 1, SOUTH 4.1km ON PTH 13, ON WEST SIDE OF ROAD
CP-2001	VALVE STATION, SW-36-6-5-W, FROM PTH 3, NORTH 1.3km ON PTH 13 (CARMAN MAIN ST), WEST 1.3km, ON NORTH SIDE OF ROAD
CP-2002	VALVE STATION, NE-26-4-5-W, FROM PTH 23, SOUTH 3.2km ON PTH 3, (FROM PTH 14, NORTH 16.4km ON PTH 3), WEST 1.9km, ON SOUTH SIDE
CP-2003	VALVE STATION, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 200m, ON NORTH SIDE OF ROAD

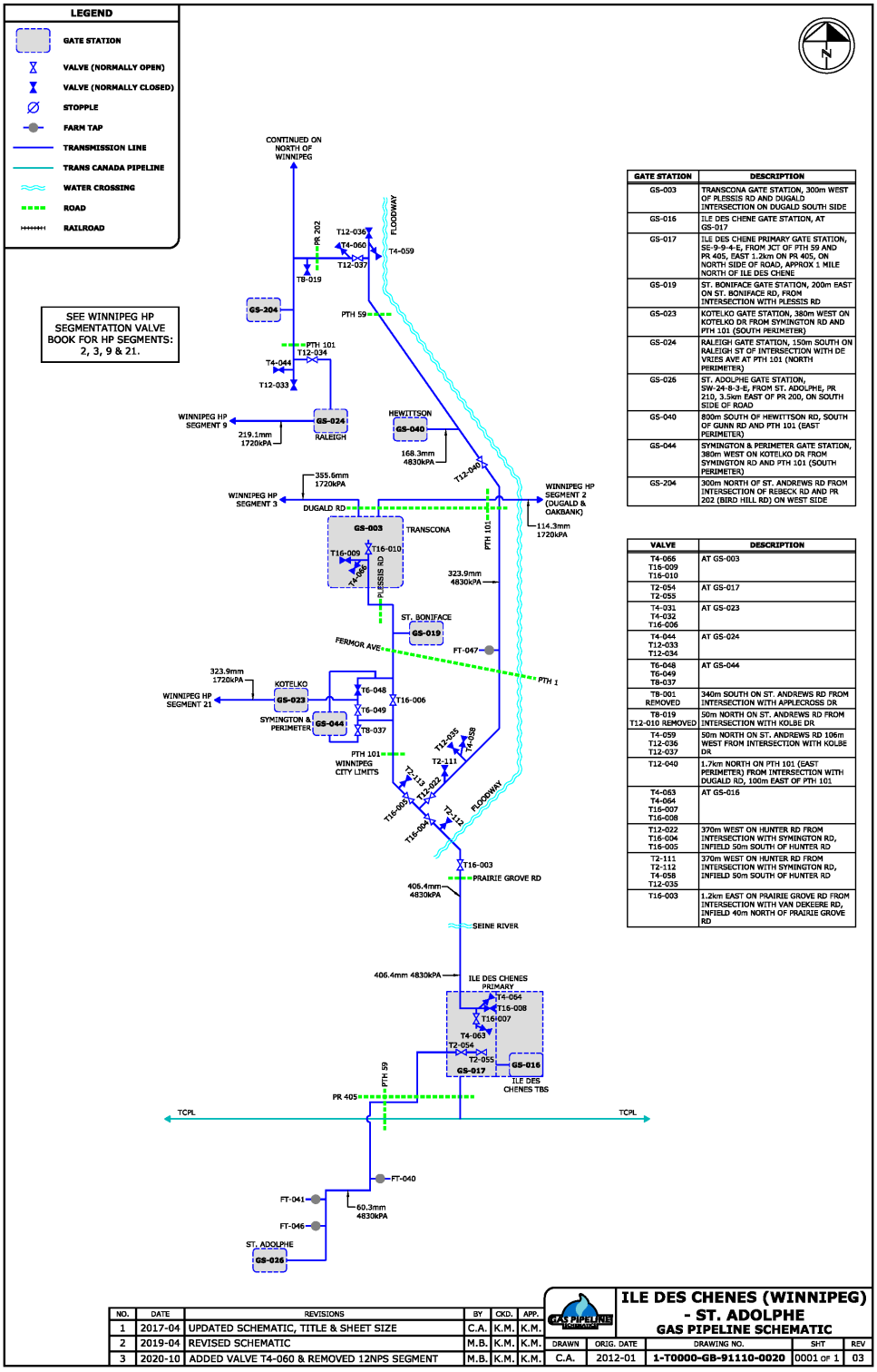
VALVE	DESCRIPTION
ELI T4-001	NE-27-10-4-W, FROM OAKVILLE PRIMARY, NORTH 1.2km ON PTH 13, EAST 6.9km, NORTH 1.6km ON WEST SIDE OF ROAD
ELI T2-001	SE-7-11-3-W, FROM PTH 1, SOUTH 700m ON PR 248, WEST 6.6km ON ELIE ST W, NORTH 35m, ON WEST SIDE OF ROAD
OVL T6-001 OVL T6-002 OVL T4-002 OVL T4-003	AT GS-136, OAKVILLE PRIMARY STATION
ELM T6-001 ELM T6-002 ELM T6-003	AT GS-138, ELM CREEK GATE STATION
ELM T4-001	NE-24-8-5-W, FROM GS-138, SOUTH 425m
CAR T6-001 CAR T6-002 CAR T4-003	CP-2001, SW-36-6-5-W, FROM PTH 3, NORTH 1.3km ON PTH 13 (CARMAN MAIN ST), WEST 1.3km, ON NORTH SIDE OF ROAD
CAR T4-001	SE-11-5-5-W, FROM PTH 3, WEST 1.9km ON PTH 23, ON NORTH SIDE OF ROAD
CAR T4-002	SE-14-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 1.6km, WEST 170m, ON NORTH SIDE OF ROAD
CAR T4-004 CAR T6-003 CAR T6-004	CP-2002, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 200m, ON NORTH SIDE OF ROAD
CAR T4-005 CAR T4-006 CAR T6-005 CAR T6-006 CAR T6-007	CP-2003, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 170m, ON NORTH SIDE OF ROAD
MDN T3-001 MDN T3-002 MDN M4-001 MDN M4-002	AT GS-139, MORDEN GATE STATION
WKR T4-001 WKR T4-002 WKR T2-001 WKR T2-002	AT GS-140, WINKLER GATE STATION

NO.	DATE	REVISIONS	BY	CKD.	APP.
2	2019-04	REVISED VALVE T6-001 ADDED FARM TAP 423 & 427	M.B.	K.M.	K.M.
1	2017-09	REVISED SCHEMATIC	C.A.	L.G.	L.G.

DRAWN: C.A.
CHKD. DATE: 2012-01
DRAWING NO: 1-T0000-GB-91110-0019
SHT: 0001 of 2
REV: 01

GAS PIPELINE SCHEMATIC
SOUTH LOOP





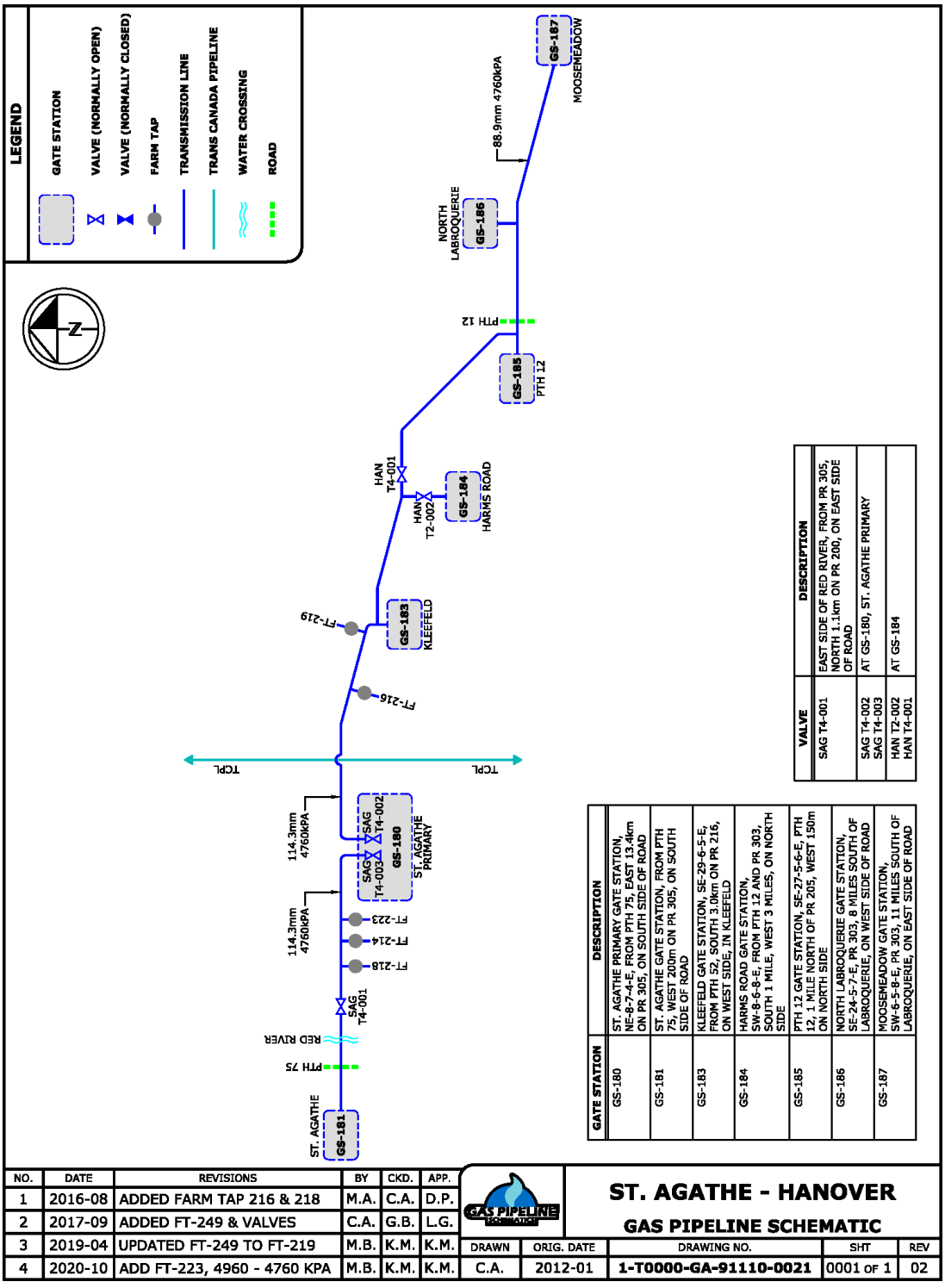
GATE STATION	DESCRIPTION
GS-003	TRANSCONA GATE STATION, 300m WEST OF PLESSIS RD AND DUGALD INTERSECTION ON DUGALD SOUTH SIDE
GS-016	ILE DES CHENE GATE STATION, AT GS-017
GS-017	ILE DES CHENE PRIMARY GATE STATION, SE-9-9-4-E, FROM JCT OF PTH 59 AND PR 405, EAST 1.2km ON PR 405, ON NORTH SIDE OF ROAD, APPROX 1 MILE NORTH OF ILE DES CHENE
GS-019	ST. BONIFACE GATE STATION, 200m EAST ON ST. BONIFACE RD, FROM INTERSECTION WITH PLESSIS RD
GS-023	KOTELKO GATE STATION, 380m WEST ON KOTELKO DR FROM SYMINGTON RD AND PTH 101 (SOUTH PERIMETER)
GS-024	RALEIGH GATE STATION, 150m SOUTH ON RALEIGH ST OF INTERSECTION WITH DE VRIES AVE AT PTH 101 (NORTH PERIMETER)
GS-026	ST. ADOLPHE GATE STATION, SW-24-8-3-E, FROM ST. ADOLPHE, PR 210, 3.5km EAST OF PR 200, ON SOUTH SIDE OF ROAD
GS-040	800m SOUTH OF HEWITTSON RD, SOUTH OF GUNN RD AND PTH 101 (EAST PERIMETER)
GS-044	SYMINGTON & PERIMETER GATE STATION, 380m WEST ON KOTELKO DR FROM SYMINGTON RD AND PTH 101 (SOUTH PERIMETER)
GS-204	300m NORTH OF ST. ANDREWS RD FROM INTERSECTION OF RESECK RD AND PR 202 (BIRD HILL RD) ON WEST SIDE

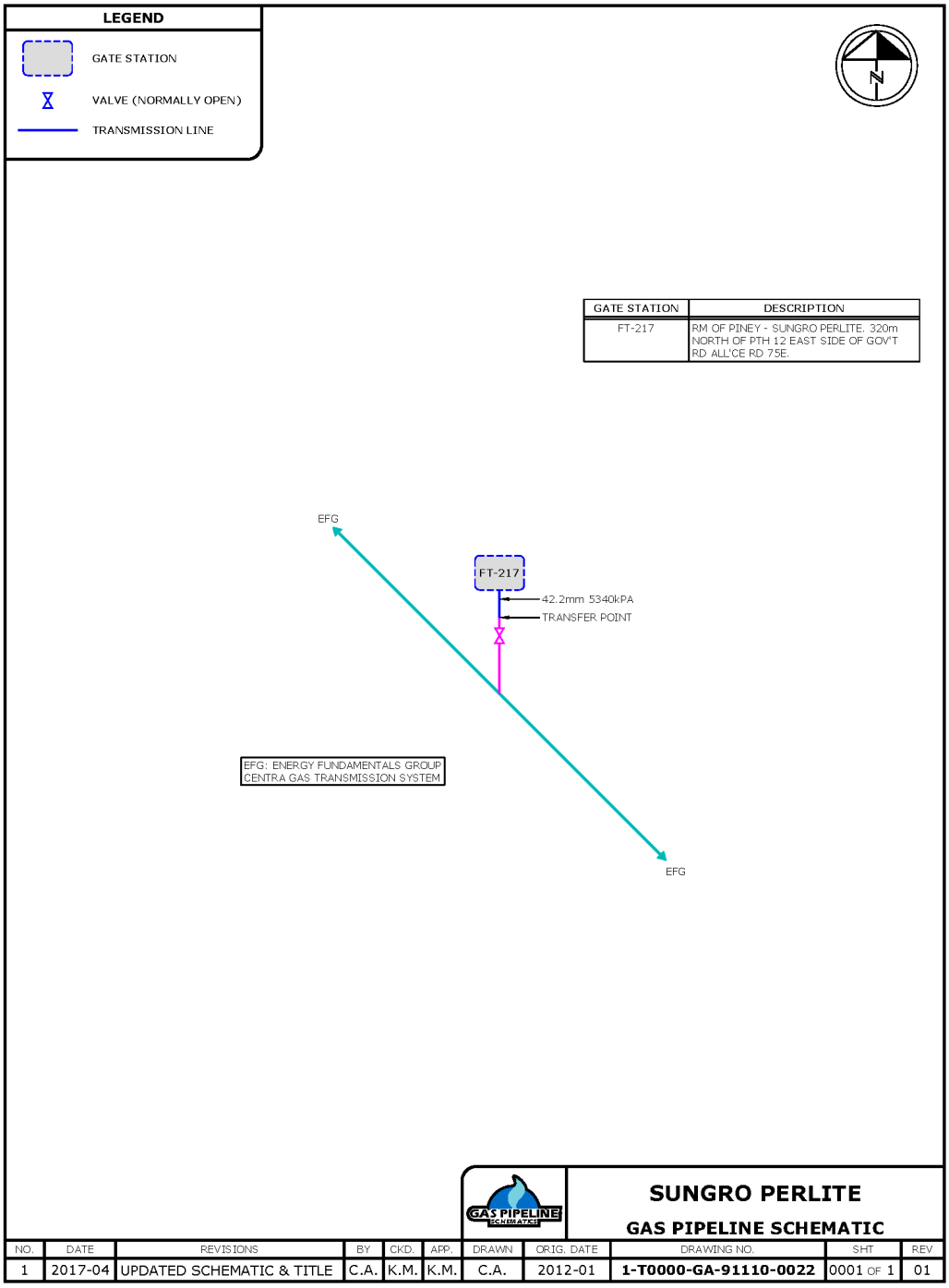
VALVE	DESCRIPTION
T4-066 T16-009 T16-010	AT GS-003
T2-054 T2-055	AT GS-017
T4-031 T4-032 T16-006	AT GS-023
T4-044 T12-033 T12-034	AT GS-024
T6-048 T6-049 T8-037	AT GS-044
T8-001 REMOVED	340m SOUTH ON ST. ANDREWS RD FROM INTERSECTION WITH APPLECROSS DR
T8-019 T12-010 REMOVED	50m NORTH ON ST. ANDREWS RD FROM INTERSECTION WITH KOLBE DR
T4-059 T12-036 T12-037	50m NORTH ON ST. ANDREWS RD 106m WEST FROM INTERSECTION WITH KOLBE DR
T12-040	1.7km NORTH ON PTH 101 (EAST PERIMETER) FROM INTERSECTION WITH DUGALD RD, 100m EAST OF PTH 101
T4-063 T4-064 T16-007 T16-008	AT GS-016
T12-022 T16-004 T16-005	370m WEST ON HUNTER RD FROM INTERSECTION WITH SYMINGTON RD, INFIELD 30m SOUTH OF HUNTER RD
T2-111 T2-112 T4-058 T12-035	370m WEST ON HUNTER RD FROM INTERSECTION WITH SYMINGTON RD, INFIELD 50m SOUTH OF HUNTER RD
T16-003	1.2km EAST ON PRAIRIE GROVE RD FROM INTERSECTION WITH VAN DEKEERE RD, INFIELD 40m NORTH OF PRAIRIE GROVE RD

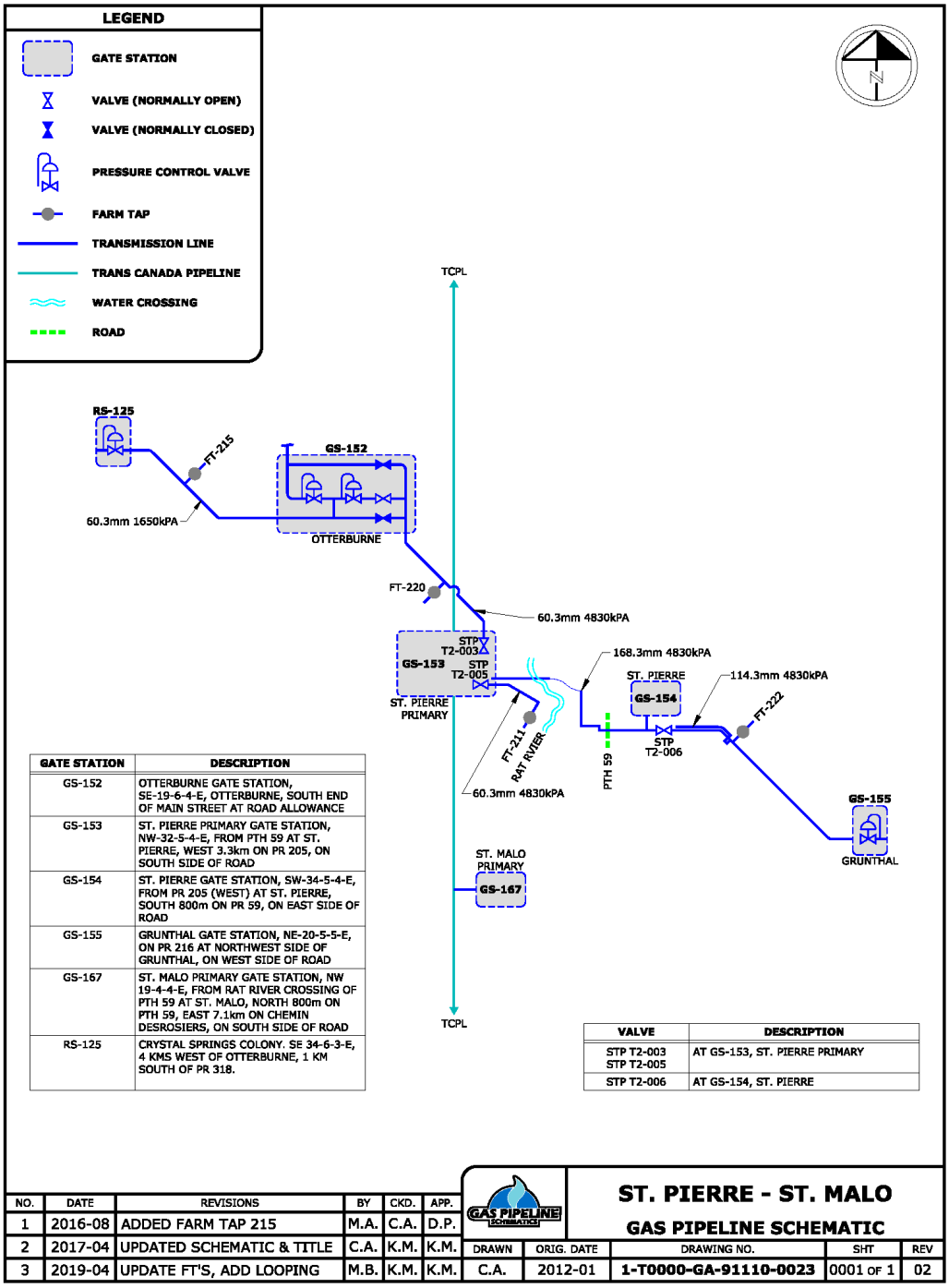
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-04	UPDATED SCHEMATIC, TITLE & SHEET SIZE	C.A.	K.M.	K.M.
2	2019-04	REVISED SCHEMATIC	M.B.	K.M.	K.M.
3	2020-10	ADDED VALVE T4-060 & REMOVED 12NPS SEGMENT	M.B.	K.M.	K.M.

ILE DES CHENES (WINNIPEG) - ST. ADOLPHE GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GB-91110-0020	0001 OF 1	03







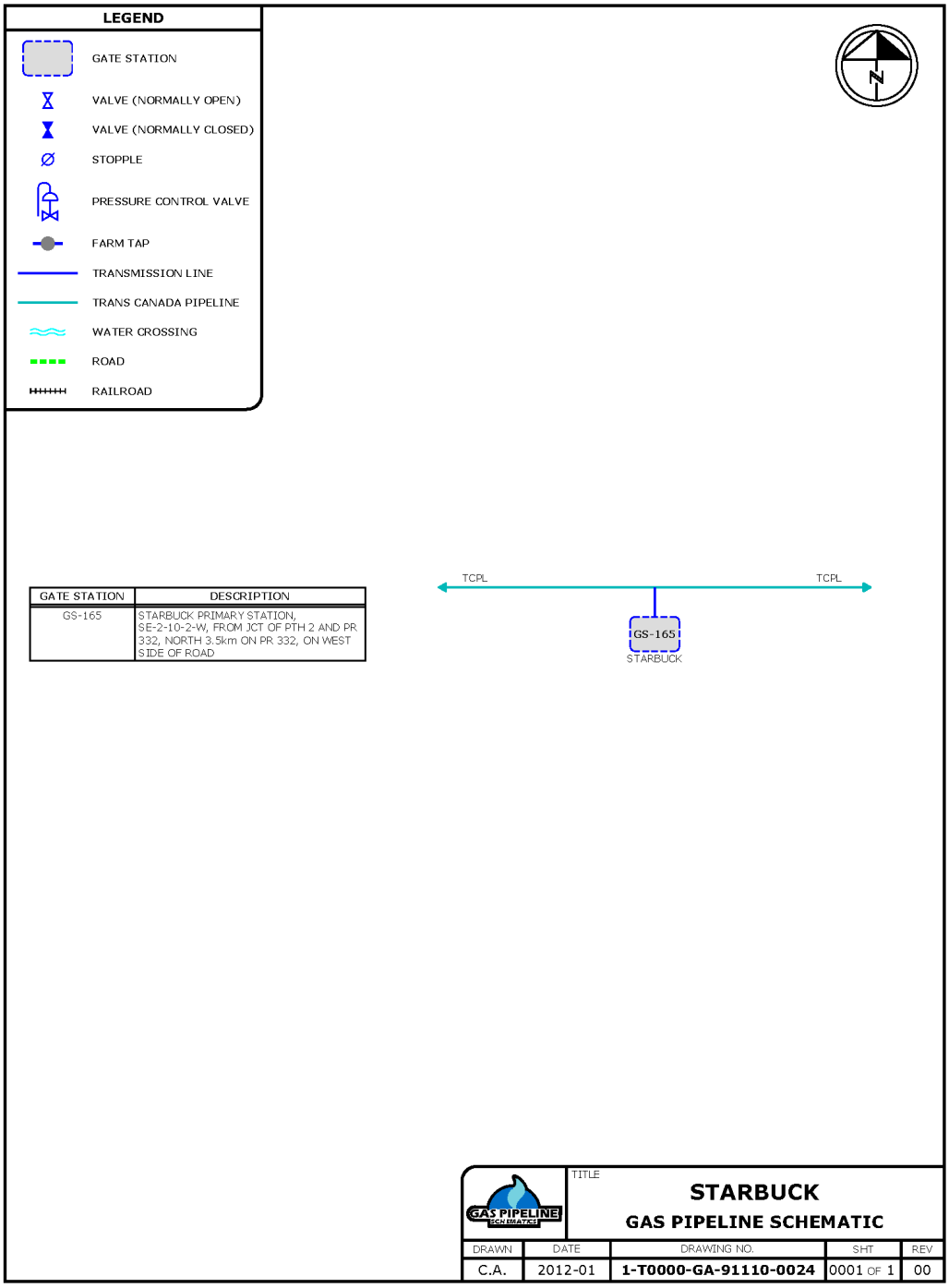
GATE STATION	DESCRIPTION
GS-152	OTTERBURNE GATE STATION, SE-19-6-4-E, OTTERBURNE, SOUTH END OF MAIN STREET AT ROAD ALLOWANCE
GS-153	ST. PIERRE PRIMARY GATE STATION, NW-32-5-4-E, FROM PTH 59 AT ST. PIERRE, WEST 3.3km ON PR 205, ON SOUTH SIDE OF ROAD
GS-154	ST. PIERRE GATE STATION, SW-34-5-4-E, FROM PR 205 (WEST) AT ST. PIERRE, SOUTH 800m ON PR 59, ON EAST SIDE OF ROAD
GS-155	GRUNTHAL GATE STATION, NE-20-5-5-E, ON PR 216 AT NORTHWEST SIDE OF GRUNTHAL, ON WEST SIDE OF ROAD
GS-167	ST. MALO PRIMARY GATE STATION, NW 19-4-4-E, FROM RAT RIVER CROSSING OF PTH 59 AT ST. MALO, NORTH 800m ON PTH 59, EAST 7.1km ON CHEMIN DESROSIERS, ON SOUTH SIDE OF ROAD
RS-125	CRYSTAL SPRINGS COLONY. SE 34-6-3-E, 4 KMS WEST OF OTTERBURNE, 1 KM SOUTH OF PR 318.

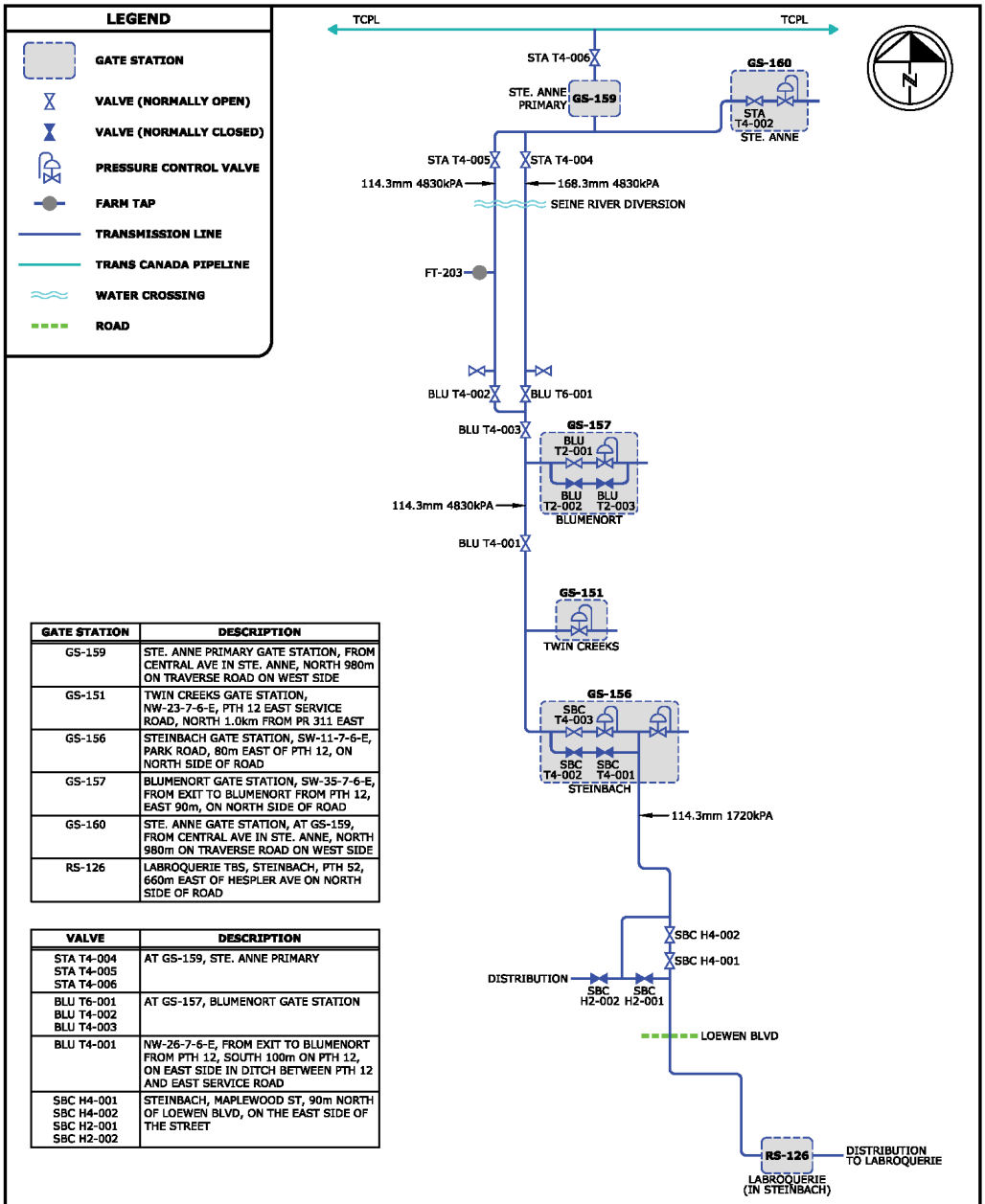
VALVE	DESCRIPTION
STP T2-003 STP T2-005	AT GS-153, ST. PIERRE PRIMARY
STP T2-006	AT GS-154, ST. PIERRE

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2016-08	ADDED FARM TAP 215	M.A.	C.A.	D.P.
2	2017-04	UPDATED SCHEMATIC & TITLE	C.A.	K.M.	K.M.
3	2019-04	UPDATE FT'S, ADD LOOPING	M.B.	K.M.	K.M.

ST. PIERRE - ST. MALO
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0023	0001 OF 1	02





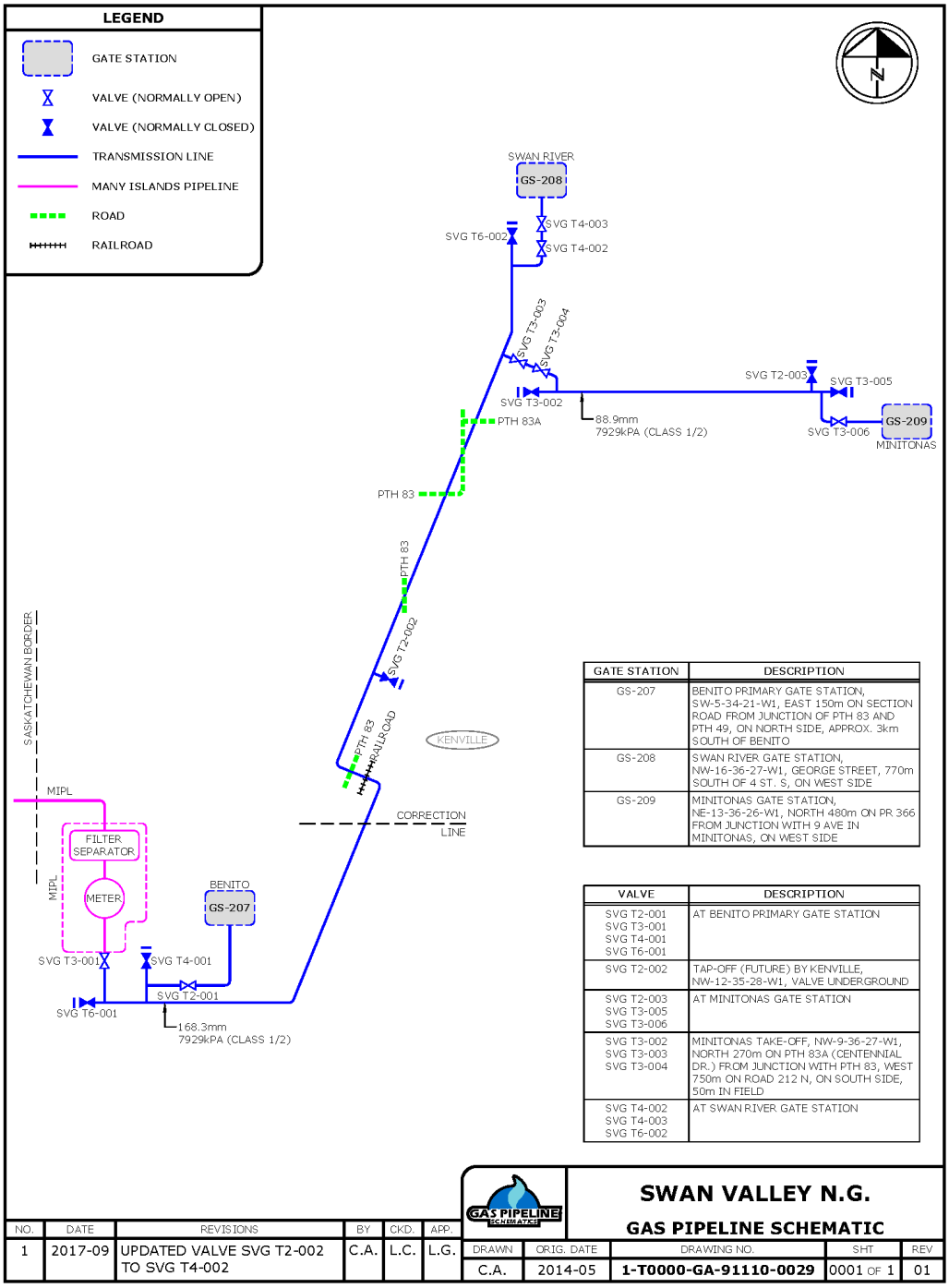
GATE STATION	DESCRIPTION
GS-159	STE. ANNE PRIMARY GATE STATION, FROM CENTRAL AVE IN STE. ANNE, NORTH 980m ON TRAVERSE ROAD ON WEST SIDE
GS-151	TWIN CREEKS GATE STATION, NW-23-7-6-E, PTH 12 EAST SERVICE ROAD, NORTH 1.0km FROM PR 311 EAST
GS-156	STEINBACH GATE STATION, SW-11-7-6-E, PARK ROAD, 80m EAST OF PTH 12, ON NORTH SIDE OF ROAD
GS-157	BLUMENORT GATE STATION, SW-35-7-6-E, FROM EXIT TO BLUMENORT FROM PTH 12, EAST 90m, ON NORTH SIDE OF ROAD
GS-160	STE. ANNE GATE STATION, AT GS-159, FROM CENTRAL AVE IN STE. ANNE, NORTH 980m ON TRAVERSE ROAD ON WEST SIDE
RS-126	LABROQUERIE TBS, STEINBACH, PTH 52, 660m EAST OF HESPLER AVE ON NORTH SIDE OF ROAD

VALVE	DESCRIPTION
STA T4-004 STA T4-005 STA T4-006	AT GS-159, STE. ANNE PRIMARY
BLU T6-001 BLU T4-002 BLU T4-003	AT GS-157, BLUMENORT GATE STATION
BLU T4-001	NW-26-7-6-E, FROM EXIT TO BLUMENORT FROM PTH 12, SOUTH 100m ON PTH 12, ON EAST SIDE IN DITCH BETWEEN PTH 12 AND EAST SERVICE ROAD
SBC H4-001 SBC H4-002 SBC H2-001 SBC H2-002	STEINBACH, MAPLEWOOD ST, 90m NORTH OF LOEWEN BLVD, ON THE EAST SIDE OF THE STREET

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	REMOVED VALVE	C.A.	A.A.	L.G.
2	2019-04	UPDATE_VALVE	M.B.	K.M.	K.M.

STE. ANNE - STEINBACH
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0025	0001 OF 1	01



GATE STATION	DESCRIPTION
GS-207	BENITO PRIMARY GATE STATION, SW-5-34-21-W1, EAST 150m ON SECTION ROAD FROM JUNCTION OF PTH 83 AND PTH 49, ON NORTH SIDE, APPROX. 3km SOUTH OF BENITO
GS-208	SWAN RIVER GATE STATION, NW-16-36-27-W1, GEORGE STREET, 770m SOUTH OF 4 ST. S, ON WEST SIDE
GS-209	MINITONAS GATE STATION, NE-13-36-26-W1, NORTH 480m ON PR 366 FROM JUNCTION WITH 9 AVE IN MINITONAS, ON WEST SIDE

VALVE	DESCRIPTION
SVG T2-001 SVG T3-001 SVG T4-001 SVG T6-001	AT BENITO PRIMARY GATE STATION
SVG T2-002	TAP-OFF (FUTURE) BY KENVILLE, NW-12-35-28-W1, VALVE UNDERGROUND
SVG T2-003 SVG T3-005 SVG T3-006	AT MINITONAS GATE STATION
SVG T3-002 SVG T3-003 SVG T3-004	MINITONAS TAKE-OFF, NW-9-36-27-W1, NORTH 270m ON PTH 83A (CENTENNIAL DR.) FROM JUNCTION WITH PTH 83, WEST 750m ON ROAD 212 N, ON SOUTH SIDE, 50m IN FIELD
SVG T4-002 SVG T4-003 SVG T6-002	AT SWAN RIVER GATE STATION

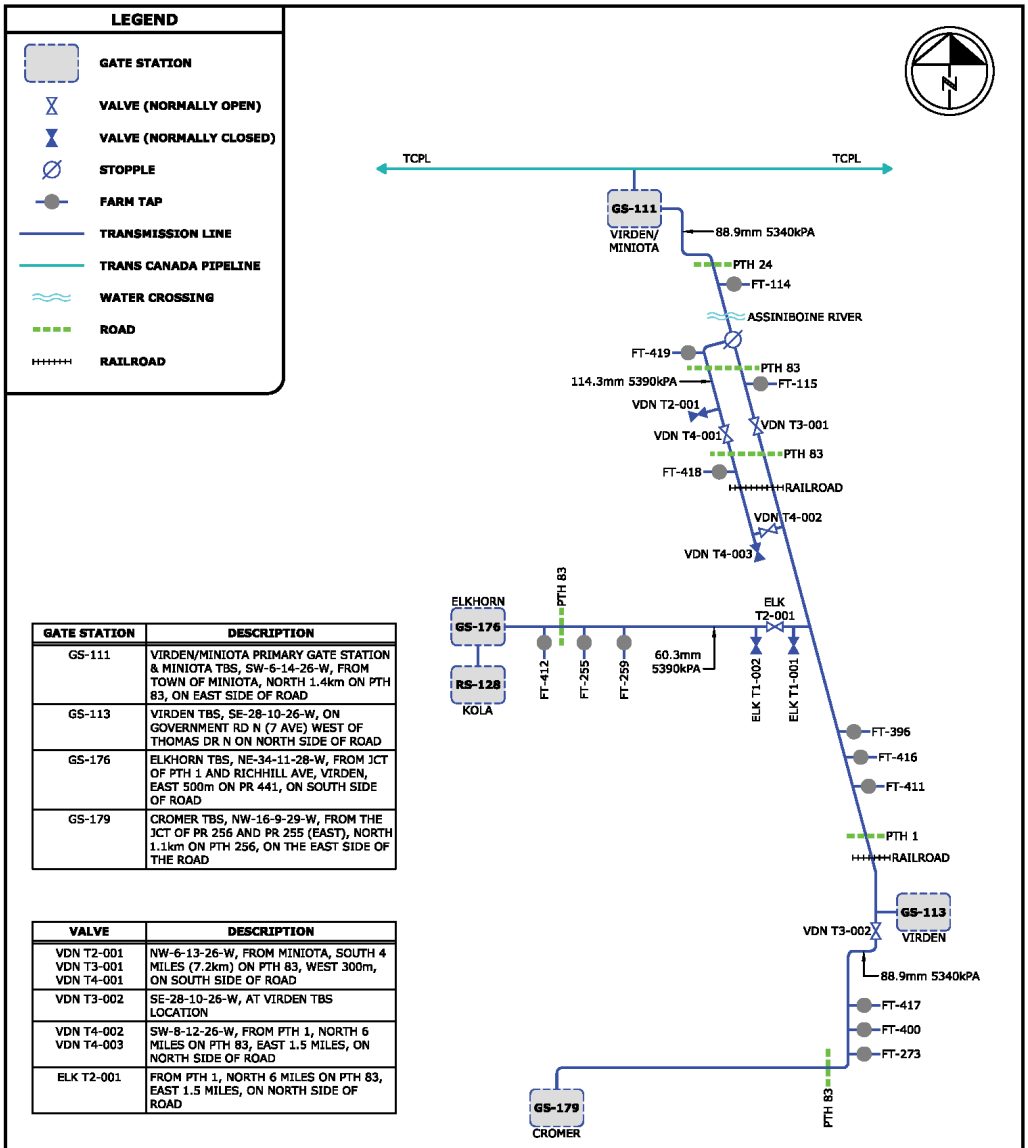
NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	UPDATED VALVE SVG T2-002 TO SVG T4-002	C.A.	L.C.	L.G.

GAS PIPELINE SCHEMATIC

SWAN VALLEY N.G.

GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2014-05	**1-T0000-GA-91110-0029**	0001 OF 1	01



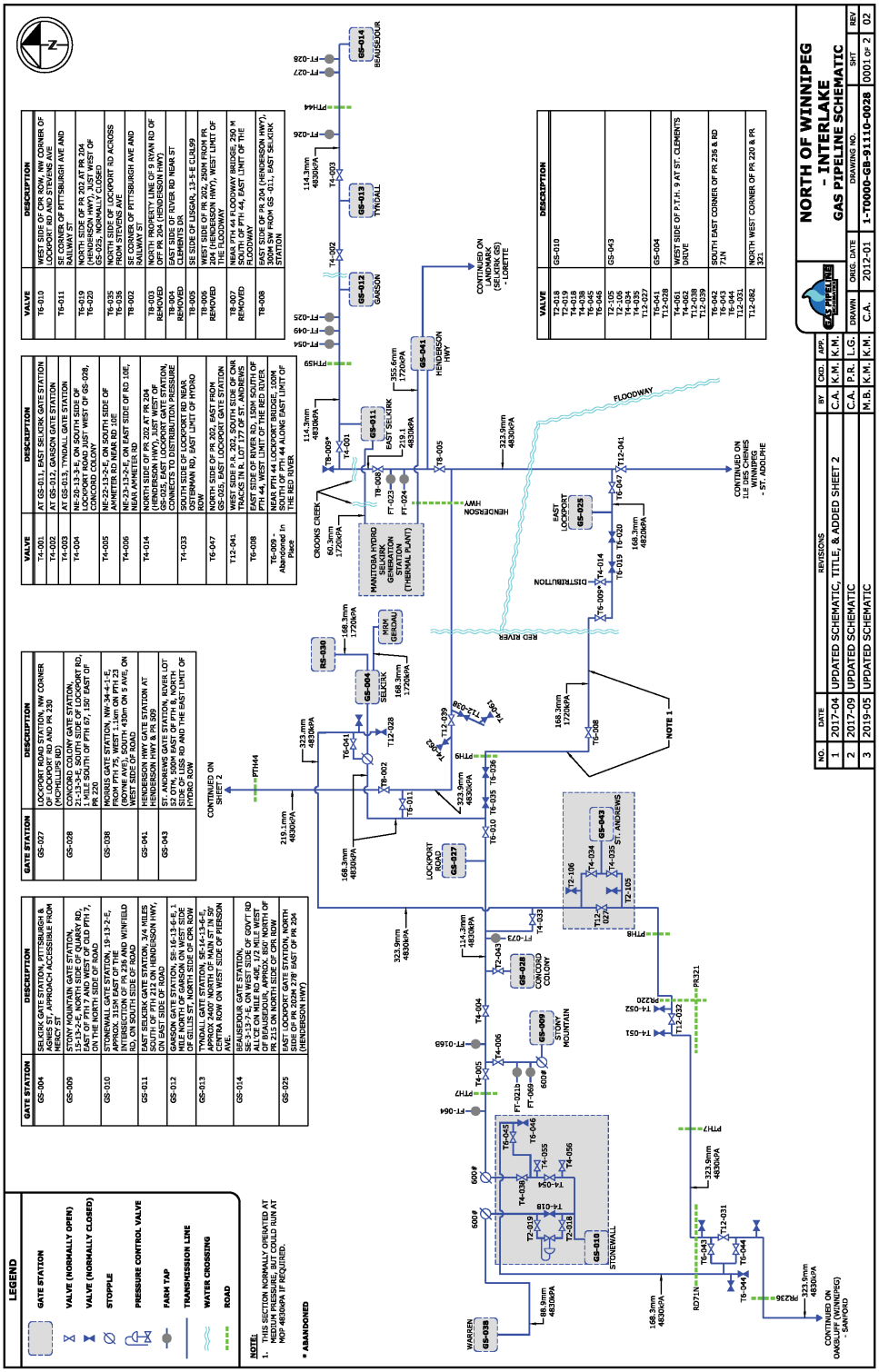
GATE STATION	DESCRIPTION
GS-111	VIRDEN/MINIOTA PRIMARY GATE STATION & MINIOTA TBS, SW-6-14-26-W, FROM TOWN OF MINIOTA, NORTH 1.4km ON PTH 83, ON EAST SIDE OF ROAD
GS-113	VIRDEN TBS, SE-28-10-26-W, ON GOVERNMENT RD N (7 AVE) WEST OF THOMAS DR N ON NORTH SIDE OF ROAD
GS-176	ELKHORN TBS, NE-34-11-28-W, FROM JCT OF PTH 1 AND RICHHILL AVE, VIRDEN, EAST 500m ON PR 441, ON SOUTH SIDE OF ROAD
GS-179	CROMER TBS, NW-16-9-29-W, FROM THE JCT OF PR 256 AND PR 255 (EAST), NORTH 1.1km ON PTH 256, ON THE EAST SIDE OF THE ROAD

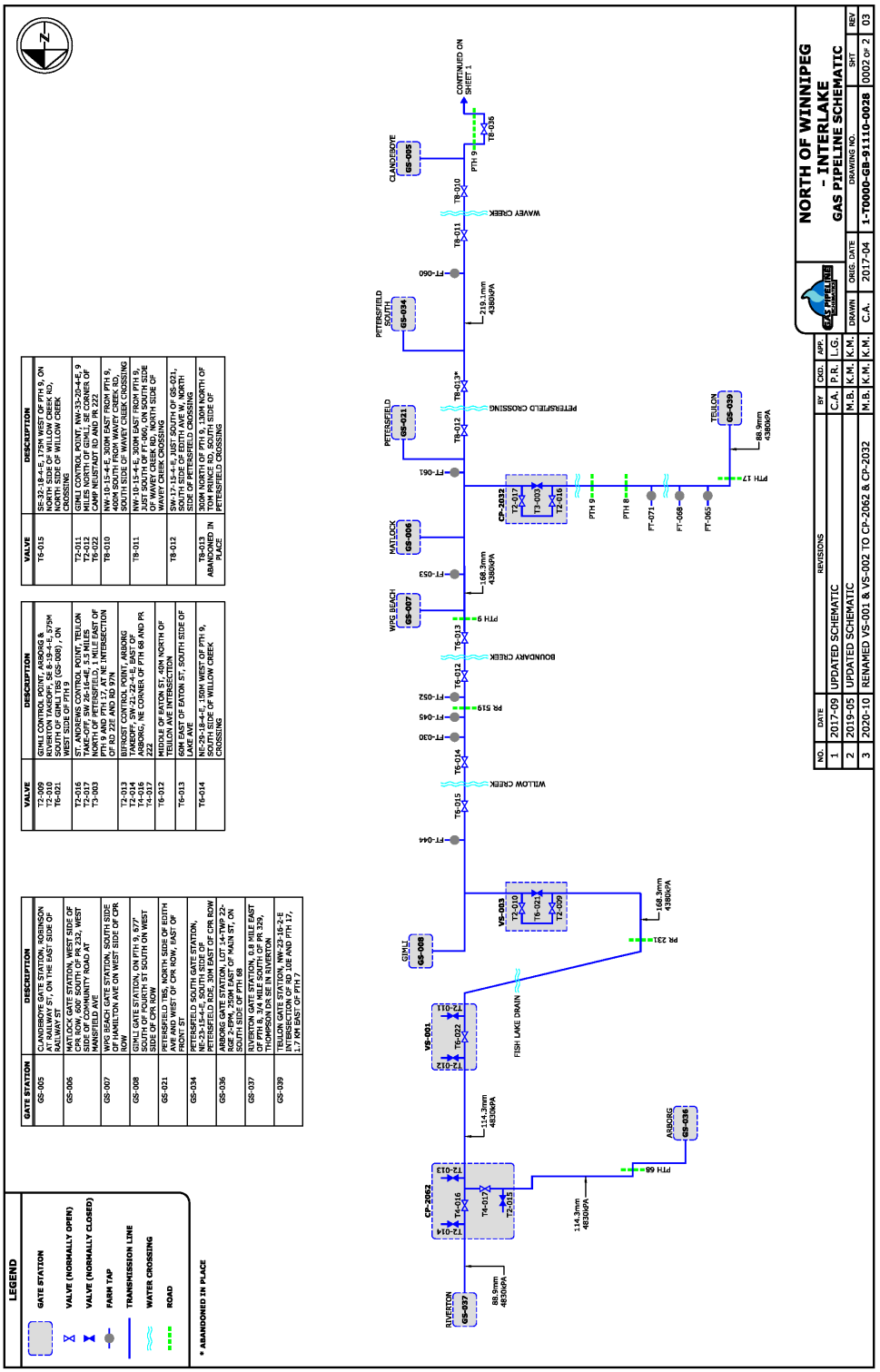
VALVE	DESCRIPTION
VDN T2-001 VDN T3-001 VDN T4-001	NW-6-13-26-W, FROM MINIOTA, SOUTH 4 MILES (7.2km) ON PTH 83, WEST 300m, ON SOUTH SIDE OF ROAD
VDN T3-002	SE-28-10-26-W, AT VIRDEN TBS LOCATION
VDN T4-002 VDN T4-003	SW-8-12-26-W, FROM PTH 1, NORTH 6 MILES ON PTH 83, EAST 1.5 MILES, ON NORTH SIDE OF ROAD
ELK T2-001	FROM PTH 1, NORTH 6 MILES ON PTH 83, EAST 1.5 MILES, ON NORTH SIDE OF ROAD

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-04	UPDATED SCHEMATIC	C.A.	L.G.	L.G.
2	2019-04	REMOVE_FT-112	M.B.	K.M.	K.M.

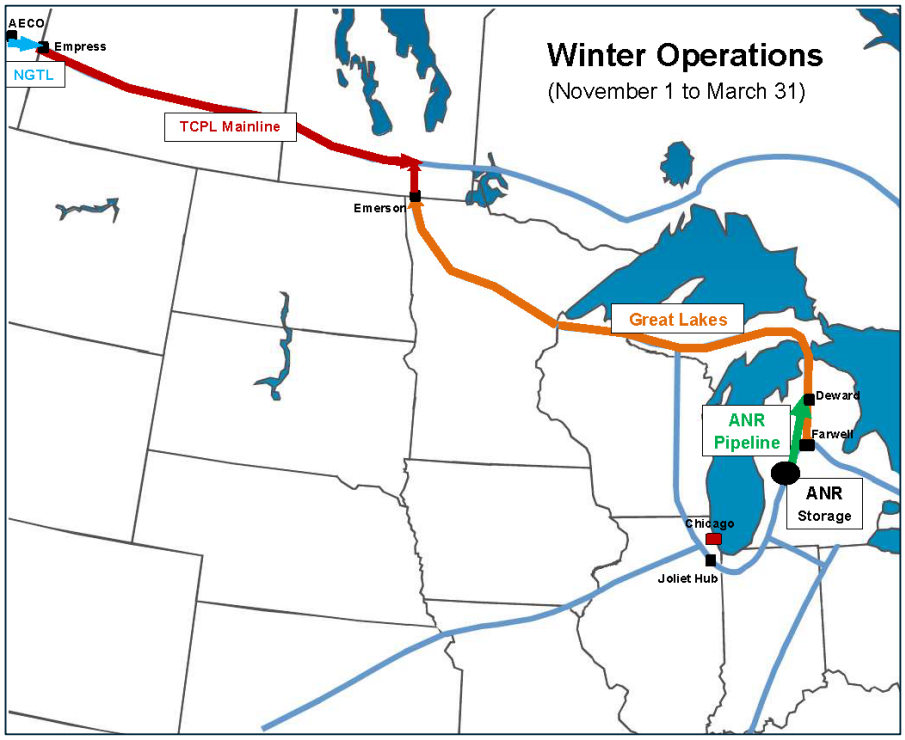
VIRDEN
GAS PIPELINE SCHEMATIC

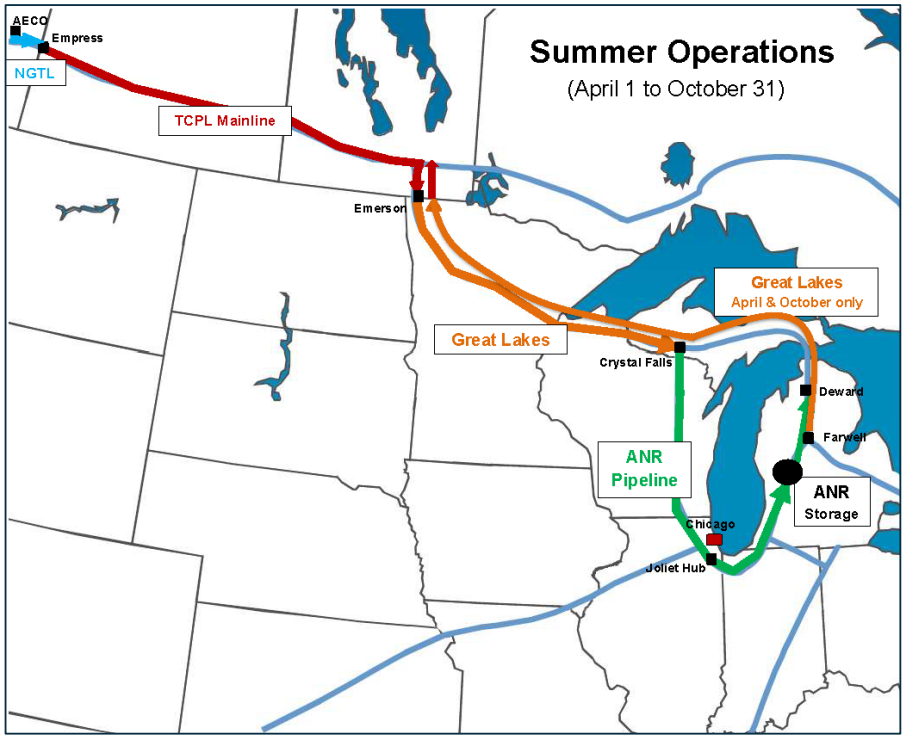
DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GA-91110-0026	0001 OF 1	01





Appendix B. Winter and Summer Pipeline Operation





Appendix C. Canadian Gas LDC Cost of Service Method Summaries

Apex (f/k/a/ AltaGas Utilities Inc.)

Summary of Allocation Methods

Based on Alberta Utilities Commission's Decision 2014-193 in Application 1610644 (2013-2017 PBR Phase II Negotiated Settlement Compliance Filing to Decision 2014-139, June 27, 2014)

I. Summary of Allocation Methods

Each revenue requirement function is classified based on the generally accepted cost drivers that can be measured in terms of how customers use the system. Costs associated with upstream functions are generally accepted to be a function of the peak demand placed on the system and are classified accordingly. At the other extreme, downstream functions, such as services and metering, are generally a function of the number of sites served.

Customer-related costs allocated based on average and weighted customers or sites.

Demand-related costs allocated to rate schedules based on coincident peak (transmission) or non-coincident peak demand (distribution mains).

Energy-related costs in AltaGas' COSS consist of Odorant and Load Settlement.

II. Allocation of Transmission Mains

Transmission mains are classified as 100% demand related and allocated to customer classes on the basis of design day (forecasted coincident peak demand assuming temperature of -40°C

III. Allocation of Stations

Pressure regulating stations are classified as 100% demand related and allocated to customer classes the basis of NCP.

IV. Allocation of Distribution Mains

Classification – Distribution Mains costs are split between demand and customer related components based on a Settlement Agreement in AltaGas' 2013-2017 PBR Phase II proceeding. Parties agreed to base the allocation on two thirds weighting of the minimum system and zero intercept cost causation models and a one third weighting on the "Benefits" approach (the benefits approach is the "Volume Length Method"). The settled classification of distribution mains costs are 43.5% customer-related costs and 56.5% demand-related.

V. Peak day Methodology

Forecast coincident peak demand (CP)

Coincident peak represents each rate class's contribution to the utility's peak demand day. This is typically measured over the period of one year, but other variants include the sum of peak summer and peak winter demands as well as the sum of daily peak demand for twelve consecutive months. This type of allocator is often paired with demand-related costs associated with the backbone of the pipeline system, such as transmission pipelines. The AUI distribution system peak occurs during the winter because most of the distribution sites and the majority of gas consumption is for heating load.

Rate 1/11 and 2/12 peak demand is calculated assuming a temperature of -40°C, consistent with the assumption used by distribution system planners for designing system capacity. This method implicitly assumes that distribution sites within both rate classes are predominantly influenced by heating load.

Rate 3/13 peak demand is based on the sum of billing demand for all sites in the rate class. By using billing demand, AltaGas is disregarding actual capacity in favor of the capacity AUI is obliged to provide. This is consistent with generally accepted cost allocation principles because Rate 3/13 customers are assured that this capacity is available whether they use it or not. AUI's infrastructure to provide this capacity is also built whether it is used or not, so the use of billing demand ensures the rate class is allocated a fair share.

Coincident peak demand for Rate 4/14, the irrigation rate class, is zero. This assumption is premised on the fact that Rate 4/14 sites take service from April to October and do not consume gas at all during the winter peak.

Forecast non-coincident peak demand (NCP)

Non-coincident peak demand (NCP) represents the peak demand day for each rate class, without regard for when the peak demand day occurs for other rate classes. This type of allocator is typically paired with demand-related costs associated with more localized distribution pipes. The sum of all rate class NCPs is by definition equal to or greater than the system peak. NCP is widely recognized as an appropriate allocator for components of the distribution system that must be designed and built to handle local peak demand situations that do not necessarily correspond to the overall system peak demand day. Note that on a system such as AUI, where consumers are almost exclusively using natural gas for heat (as opposed to industrial processes), all rate classes tend to peak at the same time. Thus, there is little difference between CP and NCP on the AUI system.

There are two differences between CP and NCP on the AUI system and both of these adjustments are made consistent with methods used in previous studies. Rate 3/13 NCP differs from Rate 3/13 CP to account for the fact that seven Rate 3/13 distribution sites are served at a higher pressure and do not rely on distribution mains. Because NCP will be used to allocate cost allocation functions such as distribution mains, AUI reduces Rate 3/13 peak demand to exclude capacity associated with sites that do not use distribution mains.

Rate 4/14 NCP also differs from CP. Rate 4/14 sites take service from April to October and AUI assumes Rate 4/14 NCP is equal to the peak month consumption divided by the number of days.

VI. Customer-related Costs

Services and Meter Asset Functions: Services and Meters are classified to Site (customer-related) and allocated based on a special study. The weighting factor for services and meters is determined by calculating the average cost for each rate class, weighted by the number of distribution sites. This method provides a more complete picture of rate class cost causation because it is able to allow for rate class specific costs and credits, such as contributions.

Meter Reading: Meter Reading is classified to Site (customer-related) and allocated based on a weighted bills study. For the meter reading function, the per-site allocation takes a number of factors into account. Firstly, all telephone communication costs are directly assigned to Rate 3/13 because all Rate 3/13 meters, and only Rate 3/13 meters are read remotely. All Rate 1/11, 2/12, and 4/14 meters are read manually by contractors, and therefore the next step is to weight site counts by the frequency of meter reads multiplied by the contractor charge-out rate. Rate 4/14 sites are manually read seven times per year whereas all other sites are read twelve times per year. Moreover, contractor fees differ based on whether the distribution site is urban, rural, commercial, or irrigation. This method has not changed from prior studies, although in previous years AUI did read some meters in-house and internal per-read costs which were also included in the weighting calculation. Now that contractors are responsible for all manual meter reads, in-house meter read costs are zero and not included in the weighting calculation.

Customer Care Functions: Customer Care functions are allocated on the basis of the aggregate number of bills issued to each rate class. Calculated by multiplying the number of sites by billing frequency, this allocator is more appropriate than a straightforward sites allocator because of the seasonality of Rate 4/14. Rate 4/14 sites are read seven time per year whereas all other sites are read twelve times per year. Customer Care functions, classified to Site (customer-related) and allocated based on Default Supply Allocation

Default supply is its own function in the study and is allocated base on default supply bills.

ATCO Gas (North)

Summary of Allocation Methods

Based on Alberta Utilities Commission's Decision 26283-D01-2021in Application 26283-A001 (ATCO Gas 2020 General Rate Application (GRA) Phase II - Compliance Filing)

I. Summary of Allocation Methods

After costs have been functionalized, the costs in each function are classified as a customer-related cost, demand-related cost, or some portion thereof. The classification of costs is consistent with Decisions 2010-291 and 2013-035 as described further below.

Customer-related costs allocated based on average and weighted customers.

Demand-related costs allocated to rate schedules based on non-coincident peak demand.

There are no Energy-related costs in ATCO Gas's COSS.

II. Allocation of Transmission Mains

ATCO removed the transmission function from its COSS in 2010. In Decision 2010-573, the Commission approved the recovery of the cost of third-party transmission service, which is currently received from Nova Gas Transmission Ltd., through a separate Rider T approved on an annual basis by the Commission.

III. Special Contract Customer Direct Assignment

No Direct Assignment or allocation of costs to any customers in the COSS.

IV. Allocation of Distribution Mains

Classification – Distribution Mains costs are split between demand and customer related components based on Commission Decision 2010-291. In order to maintain rate stability, ATCO Gas has continued to use the approved methodology of classifying distribution mains costs as 35% customer-related costs and 65% demand-related costs. ATCO Gas has also continued to use the approved methodology of allocating customer-related costs based on average number of customers and the demand-related costs based on Non-Coincident Peak (NCP) Demand. The basis of the 35-65 split is based on a Negotiated Settlement Agreement (NSA). It is not based on a minimum plant study which ATCO Gas states would increase customer fixed charges.

V. Peak day Methodology

Presently, all customers in each rate group are allocated demand-related costs by way of a calculation that uses a load factor that is an average for that rate group. This load

factor is used to determine each rate group's NCP Demand, which then determines the rate group's share of overall demand-related costs because it represents the share of demand-related costs driven by each rate group

ATCO Gas continues to allocate demand-related costs to the rate groups based on the approved methodology of NCP Demand. The NCP is the maximum expected demand by rate group at the extreme cold temperatures of -40 and -36 degrees Celsius for North and South, respectively, plus the demands of seasonal customers such as asphalt plants and irrigation customers

VI. Customer-related Costs

Billing Function: Billing costs are classified as customer-related costs. Allocated on average customers.

Call Centre Function: Call Centre costs are classified as customer-related costs. Allocated on average customers.

Meter Reading Function: Meter Reading includes the activities and assets required to provide customer meter reads. Meter Reading costs, including all costs related to AMR devices, are directly related to the number of customers served; therefore, the Meter Reading costs are classified as customer-related costs. Allocated on average customers.

Retailer Service: Retailer Service costs will not vary as a result of throughput on the system. Therefore, the costs associated with Retailer Service are classified as customer-related costs. Allocated on average customers.

Distribution Meters Function: The costs in this function include all costs for customer meters, except those costs related to AMR devices. These costs are classified as customer-related costs as approved in Decision 2013-035. Allocated on meter weighted customers.

Customer Service Function: Customer Service includes the services provided on customer premises including emergency calls for gas odors, carbon monoxide, no heat and costs related to Cut-Off for Non-Payment. The driver of these costs is the number of customers served; therefore, these costs are classified as customer-related costs. Allocated on average customers.

Classification of Distribution Services: Distribution Services costs are classified as customer-related costs as approved in Decision 2013-035. Allocated on service weighted customers.

Meters and Services: Consistent with Decisions 2010-291 and 2013-035, ATCO Gas continues to allocate Distribution Meters related costs to rate groups based on the approved methodology of weighted customer meters. This methodology compares the

average replacement costs of customer meters, which includes instruments, regulators, relief valves and meter-sets, used by each rate group to calculate a "weighted factor" for each based on the average cost of serving the customers in each rate group. These relative weightings are then applied to the average number of customers in each rate group to determine the total average weighted customers for the rate group which is used to allocate the corresponding costs.

ATCO Gas continues to allocate Distribution Services related costs to rate groups based on the methodology of weighted customer services. The current methodology for classifying distribution services costs uses residential and commercial service line cost data to assign relative weightings to rate groups. More specifically, Low Use customers are assigned a weighting based on the residential installation cost while Mid and High Use customers are assigned a weighting based on the commercial installation cost. The weighted customer service factors are then applied to the average number of customers for each rate group to determine each rate group's total average weighted customers. Finally, the weighted average customers for each rate group are used to allocate service line costs.

VII. Customer and Demand-related Costs

Administration Function: All costs in the Administration function are classified based on the composite classification of all distribution service functions' costs. Allocated on average customers and NCP demand.

Consumer Education Function: All costs in the Consumer Education function are classified based on the composite classification of all distribution service functions' costs. Allocated on average customers and NCP demand.

VIII. Gas Supply Resource Allocation

There is no gas supply in the COSS.

Enbridge Gas Distribution Inc.

Summary of Allocation Methods

Based on Ontario Energy Board's Decision and Order on Cost Awards in Case No. EB-2017-0086 (Application for natural gas distribution, transmission and storage rates commencing January 1, 2018)

I. Summary of Allocation Methods

Customer-related costs allocated based on average and weighted customers or sites.

Demand-related costs allocated to rate schedules based on coincident peak by distribution pressure system (transmission, high, and low).

II. Allocation of Transmission Mains

The Company contracts for service with Union Gas to move gas in and out of storage and to move gas delivered at Dawn. Such costs include Union's transmission demand charges and transmission fuel.

A portion of this transmission capacity is required to move gas from Dawn to the franchise area in order to meet annual demand and load balancing requirements. The costs related to the portion required to meet load balancing needs are classified as peak and seasonal load balancing. The costs associated with the portion required to meet annual demand are classified to upstream transportation charges as annual demand and allocated volumetrically, consistent with the treatment of upstream transportation costs.

The remaining capacity on Union's transmission service is used to move gas from the Company's storage operations at Tecumseh, and from storage that the Company has contracted for with Union Gas. This capacity is further classified between storage space and storage deliverability. As storage space is used to meet average winter requirements in excess of annual average demand, this transmission capacity attributable to storage space equals average daily withdrawals from Tecumseh and Union storage (approx. 40%). The balance (approx. 60%) is attributed to storage deliverability which is used to meet demand on days colder than the average winter day. This is allocated based on the rate class contribution of the excess of peak day requirements over average winter demand.

III. Allocation of Distribution Mains

The mains network is sized to meet peak demand capacity on the distribution system. It is divided into three systems based on operating pressure: transmission pressure, high pressure, and low pressure.

The first two groups are facilities for moving gas from upstream transportation facilities to the low pressure distribution grid mains network. It is essentially the grid network that ultimately provides access to gas for the Company's customers. Since the transmission and high pressure systems feed the grid mains, they have a very limited customer component and are classified entirely as capacity-related.

The low pressure grid system (1) provides natural gas access to customers or potential customers on the system, and (2) meets the volumetric demands of various customers. As a result, the low pressure system has both a capacity-related and a customer-related component. These cost components are estimated by isolating the distribution infrastructure that is needed to exist to provide customers access to natural gas service. In this Study, about 44% of the low pressure mains are classified as customer related, resulting in about 30% of total mains classified as customer-related, these proportions have remained fairly consistent over the years since the Board's EBRO 487 Decision with Reasons.

Mains is classified as approximately 30% customer-related and 70% capacity-related. Capacity-related costs are further sub-classified as transmission, high and low pressure capacity based on analysis of investments in each pressure category of mains. In the Decision to EB-2012-0459, the Board found that Rate 125 customers should not be allocated the costs of transmission pressure pipelines less than 6" in diameter. Accordingly, the transmission capacity classification is further split into TP Capacity for mains less than or equal to 4 inch in diameter (TP Capacity <=4") and TP Capacity for mains greater than 4 inches (TP Capacity>4").

IV. Peak day Methodology

The distribution system is split into three pressure systems, transmission pressure, high pressure, and low pressure. The peak throughput of each pressure level system is used, however there is no explanation about what is considered "peak throughput" (i.e. design day demand, or historical peak day, etc.)

V. Customer-related Costs

Meters: Meters are allocated based on investment in meters.

Sales Stations: Sales stations are allocated based on investment in customer sales stations.

Services: Services are allocated based on investment in services.

Customer Service: Customer service operating costs – Appliance Inspection and Locks/Unlocks/Exchanges – are classified as customer-related allocated based on total customers.

Billing & Enquiry: Billing and Enquiry are separate accounts both classified as customer-related and allocated based on total customers.

Meter Reading: Meter Reading is classified as customer-related and allocated based on readings processed per year.

FortisBC

Summary of Allocation Methods

Based on British Columbia Utilities Commission's Decision and Order G-135-18 on FortisBC Energy Inc.'s 2016 Rate Design – Project No. 3698899

I. Summary of Allocation Methods

Customer-related costs allocated based on average and weighted customers.

Demand-related costs allocated to rate schedules based on coincident peak demand.

Energy-related costs allocated based on sales volume.

II. Allocation of Transmission Mains

Transmission functions are classified as 100% demand-related since system capacity requirements are driven by the peak demand of the customer classes.

The Southern Crossing Pipeline (SCP) cost of service is included in the Transmission function and the costs are allocated to all sales and transport customers based on the peak day demand.

Background: The SCP project was approved by the Commission in 1999 as the best option to meet future requirements of FEI's customers by providing reinforcement of the Interior Transmission System, a flexible peaking resource, greater diversity of supply by providing access to Alberta markets, and other operating benefits. The SCP assets are transmission pipeline assets and the cost of service of is included in FEI's overall cost of service. The value of the third-party transportation agreements is credited against the delivery cost of service.

III. Special Contract Customer Direct Assignment

No Direct Assignment or allocation of costs to Bypass or Special Contract customers in the COSA.

Revenues associated with Bypass and Contract Rates treated as a credit to Cost of Service and allocated to all other rate schedules.

IV. Allocation of Distribution Mains

Classification – Distribution Mains costs are split between demand and customer related components based on the Minimum System approach with a Pipeline Carrying Capacity (PLCC) adjustment. The minimum system approach with PLCC adjustment was used since 2009.

PLCC Adjustment - The minimum system study (MSS) determines the minimum distribution system required to connect customers. In theory, a minimum system exists only to connect customers and not to deliver gas. However, since the MSS uses 60 mm PE as the minimum, it has a load carrying capacity. The PLCC adjustment is derived by dividing the capacity of the minimum sized distribution system by the number of customers served by the distribution system. This PLCC adjustment is then multiplied by the number of customers in each rate class, and the corresponding amount was subtracted from the peak demand for that rate class.

V. Peak day Methodology

Consistent with FEI's 1993, 1996, 2001 and 2012 Rate Design Application COSA studies, FEI has used the Coincident Peak (CP) approach to allocate demand-related costs to each rate schedule. This reflects the fact that FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers.

The customer load from FEI's test year is adjusted by the load factor of each rate schedule to estimate the peak day demand. FEI allocates demand related costs based upon the rate schedule's contribution to the system peak. The peak demand is estimated using the method described below.

FEI calculates annual load factors by region (5), by rate schedule. FEI then produces an annual weighted average load factor for each rate schedule by using the number of customers in each region to weight the load factors from those regions. Finally, FEI completes this process for three years and then averages them. Lastly, the three-year average load factor is applied to the annual volume in the COSA model to create a coincident peak day demand, which is used to allocate demand-related costs among rate schedules.

The following calculation demonstrates how FEI uses the three-year average load factor by rate schedule to derive the Load Factor Adjusted Annual Volume (or coincident peak day demand) for the heat sensitive rate schedules in the COSA model.

Peak Day Demand = Annual Consumption / (LF x 365)

VI. Customer-related Costs

Approximately 40% of FEI's customer-related costs are allocated using average customers with a weighting factor applied, 5% are allocated using only average customers and 55% are allocated based on the results of the two previous allocations.

Customer-related costs that are allocated using average customers include land, structures, mains, measuring and regulating equipment. Customer related costs that are allocated using average weighted customers include service lines and meters, customer

billing and customer contact services including supporting infrastructure and energy solutions.

Weighting average customers, and not simply using average customers, recognizes that not all customers cost the same to connect to FEI's system or cost the same to Special Studies for the Allocation of O&M, Customer Service, and Administrative Expenses.

Special Studies:

Weighting factors were calculated for each rate schedule relative to the residential rate schedule. Two types of weighting factors were developed to allocate customer costs: Weighting Factor for Administration and Billing; and Weighting Factor for Meters and Services.

Meters and Services:

The facility costs for the distribution system, such as meters, service lines and regulators, are not equal among all customers. Therefore, for these costs, FEI applies a weighting factor to the number of customers in each rate schedule so that the costs allocated to each rate schedule are proportionate to the costs to serve them.

The weighting factors are estimated values indicating the total relative value of meter and service assets associated with a specific rate schedule as compared to Rate Schedule 1. Once the weighting factors have been calculated and assigned to each rate schedule, costs can be allocated appropriately across all rate schedules. This weighting factor helps ensure each rate schedule is assigned the appropriate proportion of customer-related costs based on cost causation.

Administration and Billing:

Large customers generally require a greater level of administrative effort or customer service than the average residential customer. Customer weighting factors are required to properly allocate customer administration, marketing and billing related costs to the various rate schedules.

Based on information from FEI's marketing, customer service and billing departments, weighting factors for each rate class were developed which take into consideration:

- the frequency of meter reading
- the use of remote meter reading via cellular or other communications infrastructure and the method of collecting and retaining load data
- the amount of time spent by customer service responding to inquiries
- marketing programs and costs for different customer groups

- the existence of dedicated account managers for commercial and industrial customers
- the number of resources dedicated to each customer class for customer billing, measurement, and marketing

The customer numbers in each rate schedule that are weighted for customer administration and billing are then used to allocate costs associated with customer administration to each rate schedule.

VII. Gas Supply Resource Allocation

The current gas cost allocation methodology includes classifying the commodity costs as energy-related and allocating those costs to sales customers based on throughput; and classifying the storage and transport costs as demand-related and allocated on a load factor adjusted volumetric basis.

Pipeline Capacity and Contracted Storage Costs

The storage and transport costs are allocated to sales customers using a three-year rolling average load factor such that the basis of the allocation of the storage and transport costs is the load factor adjusted volumes (i.e., the peak day volume).

Liberty NB (f/k/a Enbridge Gas New Brunswick)

Summary of Allocation Methods

New Brunswick Energy Utilities Board Oder in Matter 178 – Rate Application (September 20, 2012)

I. Summary of Allocation Methods

Customer-related costs allocated based on costs that vary with specific customer requirements, the number of customers, or both (such as meters and service lines) - (100% classified to Customer).

Demand-related costs allocated to rate schedules based on Design Day peak demand.

Energy-related costs allocated based on sales volume.

II. Allocation of Transmission Mains

None.

III. Special Contract Customer Direct Assignment

No Direct Assignment or allocation of costs to Bypass or Special Contract customers.

IV. Allocation of Distribution Mains

Classification – Distribution Mains costs are split between demand and customer related components based on the Minimum System approach.

Minimum System resulted in a 44% Customer component for mains.

V. Peak day Methodology

Design Day Peak

VI. Customer-related Costs

Special Studies:

Meter Investment – The average cost per meter, multiplied by the average number of customers in each rate class.

Service Investment – Based on the average cost per service multiplied by the average number of customers in each rate class.

Meter Reading Expenses - Calculated using average number of customers and incorporating a weighting, using assumptions based on prior client studies/experience,

to account for differences in assumed costs between classes. The weightings account for staff time and capital.

Account 903 – Customer Accounting & Records Expense

Call Center statistics and billing expenses in a composite allocator.

Billing Expenses - Assumption based on prior client studies/experience. Allocator calculated using average number of customers with a weighting to account for differences in assumed billing costs between classes. Allocations based on interviews with billing.

Account 904 – Uncollectible Accounts Expense: write-offs experience.

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Evergreen Packaging Data Request No. 2
August 6, 2021

2-3. Please explain the basis for PSNC's system design. Please provide the most recent system-design plan, or resource plan, performed for or by PSNC, SCANA, or Dominion.

RESPONSE:

PSNC's system is designed to serve firm customers on a design day while maintaining target minimum pressures within the system (typically 30 PSIG in a 60 PSIG system). Loads are modeled using Synergi Flow Analysis software to determine if a new load can be incorporated into the existing system or if an enhancement will be required.

The Synergi flow models are updated on an ongoing basis to include new pipelines installed and new loads added to the system to update how the system will perform under design day scenarios. During this process the capacity of the regulator stations in the system are verified to see if they are sufficient to continue to serve customers and adjustments are made to the regulator stations if necessary. Yearly system planning and winter prep meetings are conducted with Engineering, Marketing, Construction, Operations & Maintenance, and Gas Supply to review system performance from the previous winter, gather data on high growth areas and new large customers, and obtain information from field personnel on potential concerns that have been identified during routine work on the system. This information is then used to create a list of enhancements needed in the system to address issues, as well as to influence design decisions on new projects going forward.

See Response 2-3 Attachment for PSNC's most recent system resource analysis.

Prepared by or under the supervision of: Andrew Moore, Director – Engineering & Construction

Dated: August 12, 2021

Public Service Company of North Carolina, Inc.
Docket No. G-5, Sub 632

Evergreen Packaging Data Request No. 1
July 19, 2021

1-24. Please provide all studies performed regarding the charges by usage block, and for summer and winter periods, for both sales and transportation rates. If no studies were performed, explain why not.

RESPONSE:

The proposal presented in this case is for no changes to the basic facility charge and for the proposed revenue increase to be recovered through an equal volumetric increase to all volumetric blocks rates. Please see the Direct Testimony of John D. Taylor at page 24. This proposal required no analysis or separate study regarding the charges by usage block, for summer and winter periods, or for sales and transportation rates.

Prepared by or under the supervision of: John D. Taylor, Managing Partner, Atrium Economics, LLC

Dated: July 26, 2021