EB-2014-0053
EB-2014-0361
EB-2015-0044

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board* Act, 1998, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas as of April 1, 2014;

AND IN THE MATTER OF the Quarterly Rate Adjustment Mechanism;

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, for an order or orders granting rate relief and/or a stay from the imposition of interest on any amounts due for payment to Union Gas Limited related to the application of certain penalty charges;

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations;

AND IN THE MATTER OF a hearing on the Board's own motion.

AFFIDAVIT OF BRIAN LIPPOLD
(Sworn March 25, 2015)

I, Brian Lippold, of the City of London, MAKE OATH AND SAY AS FOLLOWS:

1. I am the General Manager for NRG and was involved in the issues and gas purchases of NRG to meet its Winter Checkpoint Quantity under its contract with Union Gas Limited ("Union") leading up to February 28, 2014.

Part I - Introduction

2. NRG is an Ontario corporation that carries on the business of distributing and selling natural gas in the southern Ontario. NRG is regulated by the Ontario Energy Board (the "Board") under the Ontario Energy Board Act (the "Act").

3. NRG is a customer of Union Gas Limited ("Union") NRG receives gas from Union pursuant to a southern bundled T contract (the "NRG/Union Contract" (Exhibit "A"), the terms and conditions of which are attached to NRG's evidence filed with its Request to Intervene (subject to Schedule 2, which Union attached to its evidence, being Answers to Interrogatories by Union from NRG, filed as Exhibit B.NRG.15, Attachment 1 (Exhibit "B").

4. In order to appreciate my evidence, it is important to understand the geographical inter-relationship between NRG customers and Union customers, particularly in Elgin County. NRG serve approximately 7,500 residential customers and several industrial customers in a predominantly rural and small town area of the Province. Union services customers throughout a much larger territory in Ontario, some of which residential customers reside side-by-side or across the street from Union residential customers. The town of Aylmer is served exclusively by NRG.

5. Both Union and NRG are regulated by the Board under the Act and as such have responsibility for any consumers to whom they sell natural gas or provide transmission, storage or distribution service. In providing these services, NRG and Union are serving the public in the public interest as holders of a monopoly which is regulated by the Board.

6. The Board directed that this review takes place in its Decision and Order in EB-2014-0375. The Board make the following direction:

> However, the OEB does have some concerns with the narrow question of whether the implications of energy status as a natural gas distributor regulated by the OEB was thoroughly addressed in the EB-2014-0154 proceeding. This issue was not submitted by NRG as ground for motion. However, the OEB will hear this issue on its own motion. The Board will combine this review with phase 2 of NRG QRAM proceedings (EB-2014-0053). Further procedural direction will follow.

7. The issue concerning NRG's status as a natural gas distributor hereinafter be called the "NRG Status Hearing".

8. In order to appreciate NRG's evidence, it is important to review NRG's historic gas purchasing programme for checkpoint balancing gas supplies with particular reference to the obligation to supply checkpoint balancing natural gas to Union on February 28th of each year ("Winter Checkpoint Balancing"). This analysis will be characterized as the "Historic Norms" that NRG experience in purchasing gas for Winter Checkpoint Balancing supply to Union.

9. In the Winter Checkpoint Balancing process, it is important to note several facts. The first is that, if NRG fails to meet its Winter Checkpoint Balancing gas obligations on February 28, Union sells natural gas to NRG at the Penalty Rate extant at that time. Union is selling gas to

NRG for use by NRG's customers at the rate of $50.50 per GJ or whatever rate is deemed appropriate by the Board.

10. My evidence will then describe the background circumstances affecting the supply and price of natural gas in Ontario during the winter of 2013/2014.

11. My evidence will then deal with 2 Union applications made to the Board affecting NRG and NRG's customers and Union's customers. The first of these applications was commenced in the usual course by Union seeking an order effective April 1, 2014 to change its rates and other charges for the sale, distribution and storage of natural gas (Union's QRAM Application) (EB-2014-0050). The second of these applications was originally sought privately by Union in a letter to the Board seeking a right to change the penalty rate for failure to supply Winter Checkpoint Balancing gas.

12. NRG objected to Union's attempt to obtain an order regarding the penalty rate in a private process. The Board required that Union seek its relief in a public process. The Board designated the "Penalty Rate Application" as EB-2014-0154. Both of these hearings have an impact on the outcome of the two hearings presently before the Board, namely the "NRG Status Hearing" and the "NRG Phase Two QRAM Hearing".

13. Finally, the complications to be drawn from the circumstances affecting NRG, its customers, Union and its residential customers regarding the size of the penalty rate for NRG as a utility purchasing natural gas solely as a service to its customers and not for profit and in the context of Union's obligation to sell natural gas without a profit on the gas commodity will be discussed in the context of public obligations lying upon NRG and Union as enforced by the Board.

Part II – Union/NRG Geography

14. As will be hereinafter explained in my evidence, NRG operates like all utilities in the Province in purchasing natural gas for its customers, namely NRG is not allowed to profit from the sale of the natural gas commodity. Equally, NRG is not expected to suffer a loss from the purchase of the natural gas commodity, unless it had been imprudent in managing its gas purchases. The first issue to be decided by the Board is the appropriate Penalty Rate to be paid by NRG for failing to deliver a portion of its Winter Checkpoint Quantity of gas to Union on February 28, 2014 in the amount of 25,496 GJ. If NRG is required to pay $50.50 per GJ, the Penalty Rate presently fixed by the Board, it will be borne either by NRG's customers or NRG itself. Assuming that it is borne, in whole or in part, by NRG's customers then the 7,500 customers of NRG will pay $1,828,318.16 over and above Union's costs to the residential customers of Union. This amount is a windfall to Union's residential customers who obtain the benefit of the difference between Union's costs and the penalty rate fixed by the Board in EB-2014-0154.

15. Union did not purchase gas to make up NRG's shortfall in February 28, 2014. Union either did not need the gas for balancing purposes or drew it from storage at its average cost of $7.12 per GJ. The Board has directed that any Penalty Rates paid to Union over and above Union's actual gas price be held in an account for the benefit of Union's residential customers.

16. This money paid by NRG's residential customers to Union's residential customers is a complete windfall to Union's residential customers and a complete detriment to NRG's residential customers. It is NRG's regulatory obligations to protect its residential customers from such a detrimental payment that is a windall to the recipient.

17. In effect, where the franchise areas is separated only by a street, NRG's customers are delivering windfall benefits to Union's customers living as neighbours where the windfall detriment amounts did not arise from any external cost paid by Union by only the existence of penalty rate payable by customers of Union.

18. As will hereinafter set out, Union was selling the 25,496 GJ directly to NRG's customers at the penalty rate. This sale of natural gas at $50.50 is not in the public interest of consumers in the NRG franchise area and is not necessary to reimburse Union for gas cost incurred by it.

19. The geography of the Union and NRG franchises leads to an artificial negative result in that one group suffers a detriment and the other group receives a windfall as between neighbours. All of this can be rectified by Union being required to sell the 29,496 GJ to NRG for NRG's customers at Union's costs. This is the significance of NRG's status as a utility being required to purchase and sell gas without a profit and is the obligation of Union to purchase and sell gas to NRG for its residential customers without a profit.

Part III – Historic Norms

20. The circumstances prevailing during the winter of 2013/2014 will be discussed under Part IV. It has been accepted by all participants in the gas marketing field including the Board that the winter conditions prevailing during the winter of 2013/2014 were the coldest and most damaging extreme winter weather conditions on record.

21. When NRG was planning its gas purchases, it was doing so in the knowledge that it would not profit from the purchase and sale of the natural gas commodity but that it would exercise its responsibilities prudently. It is therefore important to appreciate the historic norm that NRG and all gas purchasers in Ontario had come to expect for spot market rates in Ontario during the month of February ("Historic Norm Prices"). The significance of the spot market rates is drawn from the calculation of penalty rates under the NRG/Union Contract, where the penalty rate is assessed as the highest spot market gas cost extent during the month when any shortfall occurs. In this case that month was February 2014 and the spot market rose from one day only to the unheard height of $78.73 per GJ.

22. This $78.73/GJ spot market gas cost contrasts with February penalty rates (based on the spot market gas cost extant in 2014) for the years 2006 to 2013 based on the greater of the daily spot cost at Dawn in the month and the Ontario Landed Reference Price ("Ref Price") for the month, penalty rates were $12.45, $9.33, $9.87, $9.32, $6.81, $5.37, $5.39, $5.57, respectively. In the same years (2006 to 2013), the total billed charges for all customers were approximately $78,000 (7 customers), $157,000 (5 customers), $513,000 (16 customers), $887,000 (25 customers), $116,000 (9 customers), $85,000 (7 customers), $58,000 (8 customers), $128,000 (8 customers), respectively. The total billed charges for 2014 $4,400,000 (11 customers).

23. From the above figures, the average amount paid per customer for penalty charges for the eight years prior to 2014 for the February checkpoint shortfall was approximately $23,800 per customer. The average penalty charge per customer in 2014 was approximately $400,000. This is a multiple of more than 21. Although this takes into account the difference in the Natural Gas market price, it still highlights the significant difference in the penalties currently being charged, compared to prior years.

24. These figures are taken from Union's Table 1 found at Exhibit B.NRG.12. Now produced and shown to me and marked as Exhibit "C" is a copy of that table.

25. When NRG considers its gas purchases programme during the winter of 2013/2014 and knowing that it would be required to deliver certain quantity of natural gas to Union as Winter Checkpoint volumes, it partly relied upon the historic prices set out above. As general manager of NRG this was a reasonable starting point. I will explain NRG's further steps during the months of January and February 2014 later in this affidavit. I am convinced that NRG acted prudently in its gas purchases during the winter of 2013/2014 as the winter conditions were so exceptionally bad and the prices so high that NRG's conduct can fairly only be described as prudent.

Part IV – Extreme and Unprecedented Winter 2013/2014 Conditions – NRG's Prudence

26. In the late fall and early winter of 2014/2015, the Board held a "2014 Natural Gas Market Review" (Board File No.: EB-2014-0289) (the "OEB Market Review"). The Board retained Navigant Consulting Inc. to prepare a report on the 2014 Natural Gas Market Review and a second report of the Natural Gas Price Review. I accept the testimony of Navigant filed on behalf of the Board for the purposes of my Affidavit. Now produced and shown to me marked as Exhibits "D" and "E" are copies of the Market and Price Reviews prepared by Navigant.

27. Union Gas also filed several reports in the OEB Market Review. In particular, Union Gas filed a report entitled "An Exceptional Winter". Now produced and shown to me marked as Exhibit "F" is a copy of that report.

28. The Industrial Gas Users Association filed a report in the OEB Market Review. Now produced to me and shown to me and marked as Exhibit "G" is a copy of that report.

29. I accept the Union Gas and Industrial Gas Users Association evidence as set out in Exhibits "F" and "G".

30. All parties accept in their testimony in the OEB Market Review that there were extreme cold weather conditions extant in the winter period of November 2013 to February 2014. These winter conditions were the subject of an article and a separate editorial written in the Financial Times on Thursday, June 26. Referring to North America as a whole, and the U.S. economy in particular, the article noted that the U.S. economy suffered serious economic damage due to, *inter alia*, the "country's worst winters on record". It was reported that the extreme winter conditions helped "push first-quarter domestic product figures down an annualized three percentage points more than estimated". The article quotes Paul Dales, Senior U.S. Economist at Capital Economics in London, England, saying: "...the larger contraction in GDP [USA] in the first quarter is not a sign that the U.S. is suffering from a fundamental slow-down, it is largely

due to extreme weather". The article further stated as follows: "The first-quarter figures confirm the previous picture of a terrible winter, as arctic conditions closed factories, shut transportation units, kept customers away from the shops and deterred homebuyers. There was also a huge run-down in inventories which knocked 1.7 percentage points off growth." In an editorial in the same newspaper and on the same day, an editorial writer, James MacKintosh, opined that "The U.S. economy shrank far more in the first-quarter than anyone imagined, dropping 2.9% on an annualized basis according to the latest revision yesterday. As this plunge took place in a single quarter, it does not meet the standard definition of a recession, which requires two quarterly successive drops."

31. Based on the evidence led by the OEB, Union, IGUA and NRG, it is my evidence that North America generally, and southern Ontario in particular, endured the coldest and most damaging extreme winter weather conditions from November 2013 to February 2014 on record. In addition, there were factors that were not known by NRG, namely the impact of Trans-Canada Pipelines ("TCPL") increased interruptible tolls during the winter of 2014 approved by the National Energy Board and their impact on natural gas prices at Dawn and the size and price pressure put on the price of natural gas by Union purchases during the winter of 2013/2014 and the implications for the change in pricing pressures arising from Enbridge fixing its usually floating winter checkpoint date to coincide with that of Union. The implications to be drawn from the price pressure increased by activities in the United States due to the extreme cold weather were also unknown to NRG. All of these factors were hi-lighted by the evidence led at the Board review of natrual gas markets in November and December 2014. The very fact that this helpful review was necessary and held at that time arose from the unique impact on pricing because of the factors identified individually and collectively by experts retained to look at the market, analyze the factors and report on price changes. While these might not have been sufficient individually to be new facts, collectively they represented a market in crisis in a way that was unexpected and unpredictable.

32. I give my evidence on behalf of NRG, mindful of the universally accepted position that the extreme cold weather was not predictable.

33. In purchasing natural gas to meet its Winter Checkpoint Quantity, NRG first tried to purchase natural gas for a reasonable price, and then could not purchase any gas as the winter checkpoint date arrived.

34. NRG sought Union's assistance to meet the natural gas needs and provide some relief from the looming concerns of penalty charges. While Union was polite, it gave NRG no meaningful assistance in purchasing natural gas to meet its Winter Checkpoint Quantity and refused (at that time) to grant NRG any relief from the penalty rate. Any suggestions for gas purchases made by Union did not lead to the ability of NRG to purchase sufficient natural gas to meet its Winter Checkpoint Quantity (see Exhibit B.NRG.17, attachments 1 and 2 in EB-2014-0154 (now attached as Exhibit "H").

35. NRG acted reasonably and in the public interest, having regard to the needs of its own customers and having regard to the emergency conditions that were extant during the winter season of November 2013 to March 2014. NRG did buy a substantial amount of gas at very high market rates and delivered that gas prior to February 28, 2014 in an attempt to meet all of its

Winter Checkpoint Quantity. NRG could not purchase sufficient gas such that it could be delivered by February 28, 2014. The price for spot gas fell from as high as $78.73 on February 28, 2014 to a low of approximately $17.00/GJ on the next trading day, namely March 3, 2014. Within the first week of March, the market prices dropped considerably and began to stabilize. On March 10, 2014 the trading value for gas at Dawn ranged from approximately $7.50 to $11.50/GJ (CAD). Pricing continued to fall and further stabilize in the weeks following. NRG acted reasonably in withholding its purchases during February 2014 with the reasonable expectation that prices would return to normal values prior to February 28, 2014. The exceptional conditions conspired against that reasonable expectation. The fact that price dropped substantially on the next trading day after February 28, 2014 indicates that NRG was acting reasonably.

36. It is my evidence that NRG did everything reasonably possible to meet its contractual obligations to provide the Winter Checkpoint Quantity and did nothing unreasonable in the circumstances in failing to meet 25,000 GJ of its outstanding 115,000 GJ obligation. NRG should therefore be entitled to a reduction in the penalty rate for February 28, 2014 to a reasonable price based on the historic norms indicated above for the price of gas or, in the alternative, Union's actual out-of-pocket costs.

37. NRG and its management team were diligent and watched market conditions and pricing daily. NRG also purchased gas monthly without exception. Although NRG was fully aware of the flow through cost recovery model, it was always acting to protect its customers by choosing to look for the lowest possible price available in February in keeping with past experience. By asking Union to grant a modest, short-term deadline extension into March, NRG was confident that even that small window of time would be enough to alleviate pricing pressures and bring the spot price down to historic levels.

38. When NRG was advised by Union that there was no assistance for NRG, they were forced to purchase gas at existing spot rates. NRG was able to purchase, in six transactions, the majority of its shortfall from Shell Energy at an average price of $26.81/GJ.

39. After Union denied any assistance to NRG, the utility contacted the Board to ask for assistance and intervention. No response was received from the Board in answer to NRG's plea for assistance.

40. On the days of February 26-28, NRG Managers spent their time focussed on purchasing gas in quantities sufficient to meet its' contractual requirements. NRG contacted secondary suppliers such as GoEnergy and Blackstone in attempts to purchase the remaining gas to satisfy the requirement. In addition, NRG invited match-making assistance from Union whereby Union supplied a potential contact for an in-franchise gas purchase. In spite of pursuing all avenues, NRG was unable to purchase ample gas required to completely meet its contractual obligations. NRG was advised that any further purchases of gas could not be delivered to the Dawn Hub after February 28.

41. In all of the above circumstances, NRG acted reasonably by looking towards a market solution, asking Union for assistance and being responsible to its customers in carrying out its

Natural Gas purchase and delivery obligations. NRG (and NRG's customers) should therefore only be charged Union's actual out-of-pocket costs for gas held, being $4.87/GJ to $7.31/GJ.

Part V - Union's QRAM Application and Penalty Rate Application – Spring 2014

(A) Union's QRAM Application

42. Union applied to the Energy Board for an order effective April 1, 2014 to change its rates and other charges for the sale, distribution and storage of natural gas ("Union's QRAM Request"). The Board rendered its Decision and Order on March 21, 2014.

43. In its decision, the Board noted that Union is a natural gas distributor (not a natural gas marketer). As such, Union is "not allowed to profit from the sale of the natural gas commodity". It noted that distributors have a responsibility to prudently manage gas purchases on behalf of their customers to ensure reliable service and cost effective supply. The Board noted its objectives with regard to the natural gas sector as follows: "(a) to facilitate competition in the sale of gas to users; (b) to protect the interest of consumers with respect to prices and the reliability and quality of gas service." The Board noted that the QRAM process was designed to adjust the price for regulated gas supply every quarter to reflect "natural gas market prices". Under the QRAM framework, "Union makes no profit on the gas commodity". The Board further noted that "… the actual cost of gas purchased by Union for its customers is passed on to Union's customers without any mark-up or added costs".

44. NRG requested intervenor status in the Union QRAM. NRG's intervention letter included a request that the Board grant NRG customers an exception to the application by Union of a surplus sale over consumer premium charge.

45. The NRG intervention effectively sought to eliminate the penalty rate charge which is described hereinafter of $78.73 per GJ being the highest spot rate for natural gas in February 2014 imposed on NRG because it failed to deliver all of its Winter Checkpoint Quantity causing a shortfall under the NRG/Union contract on February 28, 2014 of $25,496 GJ. The cost to NRG's customers was therefore $2,007,250. The Board did not grant any relief to NRG.

46. The Board therefore approved Union's QRAM application, as filed.

47. In exercising its jurisdiction in Union's QRAM application, the Board was exercising its public interest jurisdiction under the *Ontario Energy Board Act*, 1998 S.O. c.15 (the "Act").

48. The penalty charge of $78.73 per GJ was substantially above Union's actual average cost of gas purchases, being $7.12 per GJ. The delta amount of $71.61 per GJ was directed to be used for the benefit of Union's residential system consumers, thereby reducing those system consumers' natural gas costs. This delta amount of $71.61 per GJ was a windfall to Union's residential system customers. The amount of the windfall totalled $1,828,318.16.

49. The windfall amount will either be paid for by NRG's customers as a result of NRG's outstanding QRAM application or be shared with or borne exclusively by NRG shareholders. The decision of who bears the penalty charges will be decided in Phase II of NRG's QRAM proceeding (EB-2014-0053).

(B) Union's Penalty Rate Application (EB-2014-0154)

50. Under the NRG/Union contract, NRG is required to meet certain natural gas delivery obligations each year on September 30 and February 28. On February 28, 2014, NRG was contractually obliged to deliver 115,000 GJ being NRG's Winter Checkpoint Quantity. In the unique and harsh winter conditions extant in January and February 2014, NRG was only able to purchase 90,207 GJ and deliver that quantity to Union. The purchase was made in six transactions from Shell Energy at an average purchase price of $26.81 per GJ. NRG's total cost of the purchase for Winter Checkpoint Quantity was $2,455,576.

51. NRG was unable to purchase the remaining shortfall of 25,496 GJ for delivery at the Dawn hub before February 28, 2014. I was in charge of NRG's purchasing program. There was simply no gas available to be purchased and delivered at the Dawn hub or any other points on the Union system. NRG did everything reasonable to meet its transaction obligations to provide the Winter Checkpoint Quantity.

52. Union sold NRG the 25,496 GJ and charged NRG a penalty rate, being the highest spot rate for natural gas in February 2014, $78.73 per GJ. This is the very gas that NRG then delivered to its own customers. NRG has approximately 7,500 residential and small industrial customers residing and working in a predominantly rural and small town area of the province. The area served by NRG includes Elgin County and the Town of Aylmer, which is in the County.

53. In EB-2014-0154, Union, of its own initiative, sought a reduction in the penalty clause amount for failure to deliver the required winter checkpoint quantity of gas for the bundled T customers and other relevant users of Union. Union proposed a reduction to $50.50/GJ. The only standard and issue in that Hearing is what is the reasonable penalty amount to be charged in the circumstances.

54. NRG filed a written argument in EB-2014-0154 opposing Union's application in that NRG sought an order that the penalty rate be reduced to Union's average actual costs of natural gas on the basis that NRG was a utility operating under the flow-through gas recovery model. In that model, NRG has a public obligation to protect the interests of its consumers/customers to obtain the lowest cost of gas possible.

55. In addition, NRG is a customer of Union Gas. Union has a responsibility to provide services and, to the extent necessary, natural gas at the lowest cost. This is particularly true for the commodity as any gas purchased from Union by NRG is used exclusively for NRG's customers.

56. The Board rendered its decision accepting Union's position regarding the penalty rate amount. Now produced and shown to me marked as Exhibit "I" is a copy of the Reasons for the Board's Decision and the Board Order dated October 9, 2014. The Board fixed a penalty rate at the second highest cost of spot gas in February 2014, namely $50.50 per GJ. The delta between Union's average cost of gas at $7.12 per GJ and the Board ordered penalty rate of $50.50 per GJ is therefore $45.38 for a total on 25,496 GJ of $1,157,008.48.

57. As a result of the Board decision, the windfall paid from NRG customers (and/or NRG shareholders) to Union's residential customers now amounts to $1,157,008.48.

58. The Board summarized NRG's submissions in EB-2014-0154 as follows:

> NRG also agreed that a reduction to the penalty charges is warranted given the exceptional weather conditions experienced over the 2014 winter. However, NRG argued for an alternative penalty charge that would only be applicable to NRG, as it is a distributor and unlike the other customers who purchase their own gas. NRG stated that the Board should consider setting a penalty rate for NRG in the range of $4.87/GJ to $7.12/GJ. NRG stated that the penalty rate should be fixed on the basis of historic norms, Union's actual costs and facts specific to NRG (ie that NRG is a distributor and that it did everything it could to meet its contractual obligations).

59. The Board dismissed NRG's arguments in its order as follows:

> The Board does not find NRG's arguments concerning a different method to setting the penalty. Neither is the argument concerning NRG's special situation accepted. The Board finds that setting the penalty charge that is to be applied to NRG on the basis of historic norms or Union's gas costs is not appropriate and not consistent with the intent of the penalty. In addition, the Board is of the view that, in this matter, NRG's status as a distributor does not warrant any different treatment. As such, the Board finds that the same reduced penalty, as proposed by Union, which will be applied to all of the non-compliant customers shall also be applied to NRG.

60. The requirement that NRG checkpoint gas to Union on February 28 and at the end of September annually is recognized as a responsibility of NRG. For the 25,496 GJ that was not supplied by NRG on February 28, 2014 to Union pursuant to the NRG/Union Contract, Union effectively supplied the same amount of natural gas to NRG from its storage or other sources. Union Gas supplied the natural gas itself to make up for NRG's shortfall. It is my understanding from Union Gas that it did not actually purchase natural gas in the marketplace on February 28, 2014 but relied upon the gas it held in storage. Union's actual cost was not at the penalty rate but was purchased for $7.12 per GJ.

61. NRG made two initiatives regarding this decision.

Part VI – NRG's Subsequent Steps As A Result of the Penalty Rate Decision

62. NRG sought a judicial review of the Board's decision before the Divisional Court. Now produced and shown to me and marked as Exhibit "J" is a copy of the Notice of Judicial Review.

63. NRG also brought a motion to the OEB to review and vary the Board's decision in EB-2014-0154. That motion was dismissed in the Board's decision and Order dated March 13,

2015. Now produced and shown to me and marked as Exhibit "K" is a copy of the Board decision in EB-2015-0375.

Part VII - Public Interest Implications for NRG and Union Gas from the Penalty Rate Cost of Gas

64. In assessing the implications of NRG's unique position as a customer of Union Gas and a utility itself protecting the interests of Ontario ratepayers in the public interest, both Union Gas and NRG have a public obligation to ensure the lowest possible price. In that NRG has no capacity to achieve a profit and has a primary obligation to protect its ratepayers/customers to whom it is responsible, Union Gas has the same public obligation. Through rate regulation, the Ontario Energy Board has the same public obligation to all consumers in Ontario.

65. In looking at the various public obligations to protect NRG's ratepayers, Union Gas has a continuing obligation to protect NRG's ratepayers because Union Gas must look through the corporate structure of NRG and determine what is in the best interests of NRG's customers/consumers. This is not to deny the responsibilities of NRG, but it is to recognize the joint responsibilities of NRG and Union Gas in this regard.

66. No other customer of Union Gas stands in the unique position of NRG. Industrial gas customers who purchase natural gas directly in the marketplace for energy and production, are entitled to make a profit through the use of the natural gas they purchase. The industrial customers assume the commercial risk of natural gas pricing. There is no public obligation on any public utility to protect those consumers from natural gas pricing variability. In this regard, the industrial gas users are significantly different than NRG.

67. Because of the emergency conditions in Ontario, the reasonable analysis should begin with the historical norms and/or with Union's own cost of spot gas for February delivery, namely, $7.31/GJ (actual average cost of spot gas purchased by Union for February delivery). If you look at the years 2006 to 2013 the penalty rate in 7 of those years equalled the Ref price and in only 1 of those years did it exceed this price by $1.69/GJ. So based on historical data a reasonable penalty rate would be in the range from the Ref Price ($4.87/GJ) to the Ref Price plus $1.69/GJ ($6.56/GJ) and in these circumstances we would add to that the actual average cost of spot gas ($7.31/GJ) for February delivery (no storage).

68. It is on this basis and on the principle that NRG as a utility is uniquely situation from any other Union Gas customer that the penalty rate should be fixed for this one time for this utility NRG based on the cost of Union Gas, namely at a range of $4.87 to $7.31/GJ.

69. The impact on the public consumer in the Province of Ontario is the paramount public interest. NRG is a utility which supplies natural gas to 7,500 residential consumers and several industrial consumers in a predominantly rural and small town area of the province. The reasonable penalty rate per GJ should be as small as possible, related to historic norms and/or sufficient to pay Union's cost of gas. Based on the historical norms hereinafter set out in paragraphs 22, and 24, the penalty rate for NRG should be in the range $4.87/GJ to $7.31/GJ.

70. The paramount public interest of the consumer is not only a mainstay of public monopoly regulation but is recognized in the flow through cost recovery model itself. The model affects

Union and NRG in these unusual circumstances. Union should not make a profit over its costs for gas sold in emergency circumstances where the ultimate cost are paid by NRG's customers in the orginary course. Even if the costs were to be shared or fully paid by NRG itself, this would be a heavy burden on NRG shareholders. This cost would eliminate NRG's profits over the last four years. This is not in the interests of NRG's customers, shareholders or publi interest rate regulations in the Province of Ontario.

71. The normal requirements for a penalty rate to enforce good behaviour on those entities purchasing natural gas directly is unnecessary for NRG in these extreme conditions and having regard to its position as a utility which does not profit from the sale of natural gas.

72. NRG recognizes that this is a one-time event and a one-time relief from the penalty rate presently fixed by the Board. It is driven by the fact that the extreme cold weather was a wholly-unpredictable, one-time cold weather event which led to a previously unseen and unimaginable spot price for gas of $78.73/GJ.

73. Union itself recognized in EB-2014-0154 that $78.73 is not reasonable in these circumstances. The only quesstion left to be determined is the proper gas purchase rate for NRG as a public utility operating under the flow through cost recovery model in the circumstances extant in the winter of 2013/2014. Having regard to the public obligation lying upon Union and NRG to protect the consumers and my evidence, including the evidence of historical norms, I believe the fair and proper way to keep Union whole, to avoid an unfair windfall between neighbours, to avoid an unfair detriment to NRG's residential customers and to maintain the overall public interest to protect consumers in Ontario is to fix the penalty rate for NRG and its customers at Union's cost of $7.21.

Part VIII – Differences Among Union's Private Sector Customers and NRG As A Utility

74. NRG is required to purchase a daily volume of natural gas under its contractual obligations to Union. NRG's daily input are fixed well in advance of the heating season but its output (overall franchise consumption) is variable. Therefore, during the heating season, NRG is unable to control its consumed volume. Put differently, NRG cannot force its 7,500 residential customers to reduce the heating in their homes in order to reduce overall franchise consumption.

75. Private enterprise customers of Union who are also direct gas purchase entities are able to make their purchase decisions based on economics. Large facilities like Ford or Toyota can shut down production lines or decrease physical plant temperatures to diminish their overall consumption of natural gas in times of emergency and where they are required to meet winter checkpoint obligations. Hospitals and universities operate with co-generation facilities giving them the ability to switch to hydro to meet their natural gas consumption restrictions. In any event, commercial customers make profit from their activities and can raise prices to recover high input costs whenever necessary.

76. In short, NRG as a regulated utility, is trying to minimize cost of the natural gas commodity to its rate payers and pass those savings on to its rate payers. A non-utilitiy direct gas industrial consumer has several means to either avoid over-using their gas consumption limits with their contracts with Union or to recover any additional commodity costs through

higher prices. For example, industry has the ability to reduce their natural gas consumption by shutdowns, change in shift times and change in heating or cooling environments. In addition, the natural gas cost may be a small component of the overall manufacturing or production costs, and thereby have a smaller impact upon the enterprise than the much larger impact of natural gas costs on NRG and its customers.

77. Direct marketers may pool gas contracts. They can use positive banked gas volumes for underconsuming clients to cover the deficit gas positions of other clients at the time of checkpoint. This allows direct marketers to shift gas and ensure that they meet checkpoint balancing commitments and minimize the need for storage or next day gas purchases.

78. NRG does not have the flexibility of its industrial customers of Union and marketers. In addition, NRG can make no profit on gas. Asking NRG ratepayers or NRG itself to bear the brunt of a penalty cost unrelated to Union's cost creates an undue hardship to the utility and its shareholders and a windfall to Union's shareholders is not justified from a practical or regulatory prospective.

79. For all of the above reasons, NRG should be treated differently and an industrial customer when the Board fixes a penalty rate for NRG's shortfall in its winter checkpoint supply obligations for February 2014. The Board should fix the rate at Union's cost. The Board should weigh the analysis in favour of NRG's consumers as oppose to enforcing the penalty aspect of the contract. This latter point is available only in the extreme conditions found in 2013/2014.

80. NRG's gas costs are prudent in the circumstances. The NRG QRAM Phase 2 decision should recognize that fact and commit the cost to flow throgh to NRG's customers in the same way as gas costs flowed through to Union's customers in the same period.

SWORN BEFORE ME at the City of St. Thomas, in the Province of Ontario, this 25th day of March, 2015.

, a Commissioner for taking Affidavits.

Brian Lippold

Exhibit "A"

Contract ID	SA918-24
Contract Name	NRG
DUNS#	207734815

This Southern BUNDLED T GAS CONTRACT ("Contract"), made as of the 1st day of October, 2004.

This is Exhibit "A" referred to in the affidavit of Brian Lippold sworn before me, this 26th day of March 20 15

A COMMISSIONER FOR TAKING AFFIDAVITS

BETWEEN:

UNION GAS LIMITED

hereinafter called "Union"

- and -

Natural Resource Gas Limited

hereinafter called "Customer"

WHEREAS the intent of this Contract is for Union to provide Services, on a bundled basis, whereby Union receives daily quantities of Gas from Customer; and either stores or delivers Gas to Customer for the End User locations under Gas Distribution Contracts according to their respective Rate Schedule;

AND WHEREAS if applicable, Agent has represented and warranted that it has the authority and right to act as agent for the End Users listed in Schedule 3.

IN CONSIDERATION of the mutual covenants contained herein, the parties agree as follows:

1 INCORPORATIONS

The following are hereby incorporated in and form part of this Contract:

a) Contract Parameters contained in Schedule 1 as amended from time to time; and
b) The latest posted version of the Bundled T Terms and Conditions contained in Schedule 2 subject to Section 12.18 of Union's General Terms and Conditions; and
c) End Use List in Schedule 3; and
d) The latest posted version of Union's General Terms and Conditions subject to Section 12.18 of Union's General Terms and Conditions.

2 PRELIMINARY AND CONTINUING CONDITIONS

This Contract and the rights, and obligations of the parties hereunder shall be conditional upon the fulfillment and maintenance in good standing of the following conditions:

a) If required under the General Terms and Conditions financial assurances shall be supplied and maintained with Union; and
b) Customer and Union shall have executed, delivered and maintained in good standing the Gas Distribution Contract(s); and

c) If required, Agent shall have a valid Gas Marketer's License as defined by the OEB Act and Regulations.

The above conditions must be initially satisfied by Customer or Agent 25 days prior to the Day of First Receipt.

3 CONTRACT TERM

This Contract shall be effective from the date hereof. However, the Service, obligations, terms and conditions hereunder, shall commence on the Day of First Receipt. Subject to the provisions hereof, this Contract shall continue in full force and effect for each Contract Year until Notice to terminate is provided by either Union or Customer/Agent. Such Notice must be delivered at least three (3) months prior to the end of a Contract Year.

4 SERVICES PROVIDED

Union agrees to provide Service under the terms and conditions as set out in this Contract and the referenced attachments. Subject to Authorization Notice being granted by Union, Service under this Contract shall be Firm for the quantities and Receipt Points as specified in Schedule 1.

5 RATES FOR SERVICE

Customer agrees to take and pay for Services herein according to the terms and conditions of the following:

a) Rate Schedule R-1 as it may be amended from time to time by the Ontario Energy Board; and
b) this Contract and the incorporations hereto.

6 NOTICES

Notices shall be delivered pursuant to the Notice provision of the General Terms and Conditions and delivered to the addresses as referenced on Schedule 1.

7 CONTRACT SUCCESSION

This Contract replaces all previous Bundled T Contracts, subject to settlement of any Surviving Obligations.

8 ARBITRATION

All disputes arising in connection with this agreement shall be settled under the provisions of the Arbitration Act, 1991, S.O. 1991, c-17, as amended, by three arbitrators. Each party shall appoint one arbitrator and the two arbitrators so chosen shall appoint a third. The arbitration shall take place in Toronto. The decision of the arbitrators shall be final and binding, and from which there shall be no appeal.

SCHEDULE "1"
Contract Parameters And Notice Lists
Southern Bundled T

Contract ID: SA918-24
Contract Name: NRG

1. Dates.

"Day of First Receipt" means the 1st day of October, 2013.
The Contract Year shall expire at the end of September, 2014.
This Schedule 1 is effective October 01, 2013.

2. Daily Contract Quantity (DCQ)

Upstream Point(s) Of Receipt

LOCATION	Obligated DCQ GJ per Day
Western	563

Ontario Point(s) Of Receipt

LOCATION	Obligated DCQ GJ per Day
Parkway	1731

Obligated DCQ does not include fuel.

On Days when requested by Customer and Authorization Notice is given by Union, the above quantity parameters, Upstream Point(s) of Receipt, and Ontario Point(s) of Receipt shall be deemed to be amended in accordance with such Authorization Notice.

3. Maximum BGA Balances

All units referenced in the table below are Gigajoules (GJ).

BGA Balancing Period Date	Maximum Positive Variance	Maximum Negative Variance
September 30, 2014	33,492	-33,492

In this Schedule 1, if a BGA Balancing Period Date (other than Contract Anniversary) coincides with the Winter Checkpoint Date, the greater of the Maximum Negative Variance on the BGA Balancing Period Date or the checkpoint value will prevail. If a BGA Balancing Period Date (other than Contract Anniversary) coincides with the Fall Checkpoint Date, the lesser of the Maximum Positive Variance on the BGA Balancing Period Date or the checkpoint value will prevail.

"SCHEDULE 3"

End Use List

The location(s) stated hereunder shall collectively be defined as Point(s) of Consumption. The parties acknowledge that the Union account number(s) is for ease of administration and should any number be changed to a new number, this Contract is deemed to be automatically amended to include such new number.

For all Bundled T Contracts submitted and administered electronically by the Customer or its Agent using Unionline, the End Use List is provided in the Unionline Price Point Cross Reference Report ("Price Report").

If this Contract is executed by an Agent, then Customer shall mean the End Users referenced in this Schedule 3.

Union Account #	Consumer Name	Location
SA1550	NRG LIMITED	30040 WESTCHESTER BR DORCHESTER N TP, ON

law or jurisdiction
30 days - s.33-08B

uniongas
A Spectra Energy Company

4. Checkpoint Balancing Parameters

Checkpoint	Fall/Winter Checkpoint Date	Checkpoint Quantity (GJ)
Winter	Feb 28, 2014	-205,227

This Contract operates on the basis of:

☐ Customer Determined Balancing Option

Or ☑ Union Determined Balancing Option

5. Contact List for Notices

Customer contact information is found in Unionline. Where multiple names have been identified by Customer, Union is obligated to contact the first name only.

Union Gas contact information is found on Union's website.

The undersigned execute this Contract as of the above date. If an agent on behalf of Customer executes this Contract then, if requested by Union, Agent or Customer shall at any time provide a copy of such authorization to Union.

UNION GAS LIMITED

Jim Laforet
Manager, Contract Billing and Operational Support
Authorized Signatory

CUSTOMER

I have the Authority to bind the Corporation, or Adhere C/S, if applicable
NATURAL RESOURCE GAS LIMITED

please print name
ANTHONY GRAAT
PRESIDENT

The undersigned execute this Contract as of the above date. If an agent on behalf of Customer executes this Contract then, if requested by Union, Agent or Customer shall at any time provide a copy of such authorization to Union.

UNION GAS LIMITED

Jim Laforet
Manager, Contract Billing and Operational Support
Authorized Signatory

CUSTOMER

I have the Authority to bind the Corporation, or Adhere C/S, if applicable
NATURAL RESOURCE GAS LIMITED

please print name
ANTHONY GRAAT
PRESIDENT

uniongas
A Spectra Energy Company

10145

Exhibit "B"

This is Exhibit "B" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 2015

A COMMISSIONER FOR TAKING AFFIDAVITS

UNION GAS LIMITED

Answer to Interrogatory from
Natural Resource Gas Limited

Reference: NRG Evidence Filed May 21, 2014

By letter dated May 21, 2014 NRG sought intervenor status in EB-2014-0154. NRG filed evidence in support of its request to intervene and for relief. Does Union object to the contents of any of the evidence filed by NRG? Does Union accept all of the evidence filed by NRG? Please explain your answer in detail.

Response:

Union does not accept the evidence filed by NRG in its Request to Intervene submitted to the Board on May 21, 2014.

In paragraph 3, NRG submits that it has attached its contract with Union at Schedule 3 to its Intervention Request. This is incorrect. NRG's submission is missing Schedule 2 to the contract, the Southern Bundled T Terms and Conditions, which defines the Banked Gas Account ("BGA"), checkpoint obligations and linkage to the R1 rate schedule. Please see Attachment 1 for the omitted Schedule 2 to the Southern Bundled T contract.

In paragraph 5, NRG submits that Union had purchased sufficient gas supply to cover NRG's winter checkpoint quantity. This is incorrect. Union did not purchase gas to cover NRG's contractual obligations at a price of $12.31/ GJ. Union did not plan for, nor proactively purchase any gas supply to make up the default for any direct purchase customers not meeting their contractual obligation, including NRG. Union's planning assumptions when purchasing spot gas was that all direct purchase customers would meet contractual obligations at expiry and checkpoint. Union also attempted to assist NRG during January and February in providing options to meet their checkpoint obligations. These are described in Exhibit B.NRG.17.

In paragraph 8, NRG submits that it was unable to purchase the remainder of its shortfall as there was simply no gas available to be delivered at Dawn or any other points on Union's system. This is incorrect. As per the Enerdata CGPR Daily Report, there were over 170 trades at Dawn each day between February 25 and 28 with volumes recorded at approximately 1 PJ/d. Other customers paid the prevailing market prices to meet their obligation. Further, there were 16 Balancing Transactions that occurred on Union's system with a start date of February 28, 2014.

In paragraph 9 of NRG's submission, it states that it informed Union on March 2, 2014 of its intention to deliver the outstanding balance (25,496 GJ) in March but Union would not permit NRG to deliver this gas. This is incorrect. NRG's failure to meet its February 28 checkpoint resulted in a sale of gas to NRG per the R1 rate schedule which was invoiced to NRG on March

7, 2014. Union enforced the parties' contract given the extensive communication and to be consistent with the treatment of other direct purchase customers.

In paragraph 12, NRG submits that the penalty charge is unenforceable under the Contract and should be subject to arbitration. Union disagrees. As indicated in Union Counsel's letter to NRG Counsel dated April 21, 2014 (as filed in EB-2014-0053), Union's position is that the Board has the exclusive jurisdiction of the Board to fix rates as defined in the Ontario Energy Board Act ss. 19 and 36. The rate at which the Banked Gas Purchase Commodity Charge is set is part of Union's Board-approved R1 rate schedule and the determination of that amount falls within the exclusive jurisdiction of the Board.

In paragraph 13, NRG submits that the proper amount of the penalty should be $12.31/GJ. Union disagrees. As provided in Union's April QRAM filing (EB-2014-0050), Tab 1, p.6, Table 1, Union's actual spot gas purchases costs ranged from $4.94 to $12.31. As described in Exhibit B.NRG.24, these purchases were made under the assumption that all contractual obligations for both checkpoint and contract expiry would be met by those customers. The bundled transportation contract is in place to ensure that customers balance to their contractual commitments. The purpose of the cost consequence of the "highest price" is intended to discourage customers from making economic decisions on whether or not to comply with their contractual obligations.

Further, in paragraph 15, NRG submits that this penalty will be a windfall to Union's customers and is an undeserved detriment for NRG's customers. For clarification, the charge to DP customers is credited to Union North and Union South sales service customers to ensure that the cost consequences of DP customers failing to balance are not borne by these customers. As the Board indicated in the RP-2001-0029 Decision:

> "*the failure to balance can place compliant system participants at risk, and may result in additional costs….In the Board's view, the penalty must be sufficiently costly to defaulters to strongly discourage strategic non-compliance with balance obligations, and the careless or incompetent acceptance of contractual obligations which are not reasonably achievable. The Board is concerned that parties wishing to engage in the market, either directly or through agents, must be appropriately encouraged to manage their obligations responsibly. The system as a whole requires that.*" (p. 31).

SCHEDULE "2"

Southern Bundled T Terms And Conditions

1 UPSTREAM TRANSPORTATION COSTS

Where Union is receiving Gas from Customer at a Point of Receipt upstream of Union's system, Customer shall be responsible to Union for all direct and indirect upstream transportation costs including Compressor Fuel from the Point of Receipt to Union's system, whether Gas is received by Union or not, for any reason including Force Majeure. Where actual quantities and costs are not available by the date when Union performs its billing, Union's reasonable estimate will be used and the appropriate reconciliation will be done in the following Month.

2 OBLIGATIONS TO DELIVER AND RECEIVE

Subject to the provisions of this Contract, Union agrees to receive the Obligated DCQ parameters in Schedule 1 each Day. Customer accepts the obligation to deliver the Obligated DCQ parameters in Schedule 1 to Union on a Firm basis. On days when an Authorization Notice is given, the DCQ parameters are as defined in the Authorization Notice.

For all Gas to be received by Union at the Upstream Point of Receipt, Customer shall, in addition to the DCQ, supply on each Day sufficient Compressor Fuel as determined by the Transporter.

3 BANKED GAS ACCOUNT

The Banked Gas Account ("BGA") will be used to accumulate the daily differences between the total quantities of Gas received by Union (excluding fuel) from the Customer, and the total quantities of Gas distributed by Union to the End Use locations listed in Schedule 3, plus any BGA transactions permitted by Authorization Notice. Where the cumulative quantities received by Union exceed the cumulative quantities distributed by Union, the resulting BGA balance shall be positive. Where the cumulative quantities distributed by Union exceed the cumulative quantities received by Union, the resulting BGA balance shall be negative.

Customer shall plan and operate in a manner that will achieve a BGA balance of zero at the end of each Contract Year. In addition, Customer is expected to take balancing actions early in the summer to ensure that the BGA balance does not exceed the Fall Checkpoint Quantity as of the Fall Checkpoint Date. Customer is also expected to take balancing actions early in the winter to ensure that the BGA balance is not less than the Winter Checkpoint Quantity as of the Winter Checkpoint Date. The checkpoint quantities and dates are identified in Section 4 of Schedule 1.

Customer's ability to manage the BGA balance through changes in its supply arrangements shall require authorization from Union. Customer's request for a change does not require or obligate Union to accept a request which Union, acting reasonably, determines it cannot accommodate. If Union cannot accommodate such request, Customer shall not be relieved from its obligations for the Fall Checkpoint Date or the Winter Checkpoint Date, or any BGA Balancing Period Date.

Provided this Contract is in place for a subsequent Contract Year, that portion, if any, of the BGA balance not outside of the Maximum Positive Variance or the Maximum Negative Variance identified in Schedule 1 shall be carried forward into the BGA of the subsequent Contract Year.

3.01 Service under the Union Determined Balancing Option

Where Schedule 1 identifies the balancing option as "Union Determined Balancing Option", Section 3.01 of this Schedule 2 shall apply and Section 3.02 shall not apply.

Under the Union Determined Balancing Option, Union will determine and advise Customer of the incremental quantity of Gas that must be supplied by Customer for the BGA balance to be greater than or equal to the Winter Checkpoint Quantity as of the Winter Checkpoint Date, and the quantity of Gas that must be disposed of for the BGA balance to be less than or equal to the Fall Checkpoint Quantity as of the Fall Checkpoint Date. Customer is obligated to supply and to dispose of the quantities of Gas as determined by Union.

Winter Checkpoint

Periodically during the winter, Union will estimate what the BGA balance will be as of the Winter Checkpoint Date ("Winter BGA Balance") using recent third party weather forecasts and Customer's monthly consumption forecast. The BGA estimate will include estimated consumption, whether billed or unbilled, to and including the Winter Checkpoint Date. This information will be provided to Customer for information purposes only, and in no way limits or qualifies Customer's obligation to ensure that the actual BGA balance is greater than or equal to the Winter Checkpoint Quantity on the Winter Checkpoint Date. As the Winter BGA Balance is comprised of third party weather forecasts and Customer's consumption forecast, Union cannot make any representation or warranty as to the accuracy of the Winter BGA Balance.

During February, if Union determines that the estimated BGA will be less than the Winter Checkpoint Quantity then Union will advise Customer on or about the 10th Business Day of February of the additional quantity of Gas that must be delivered. Customer must, by the 15th Business Day of February, request approval for a balancing transaction to deliver the additional Gas. If Customer does not make a request by the 15th Business Day, or if Union has approved a balancing transaction and the Gas is not delivered in accordance with the approved balancing transaction, then Union will sell to Customer, and Customer will accept, that quantity of Gas at the Banked Gas Purchase commodity charge from the R1 Rate Schedule.

Fall Checkpoint

During September, Union will determine and advise Customer on or about the 10th Business Day of September of the quantity of Gas that must be disposed of in advance of the Fall Checkpoint Date ("Checkpoint Variance"). Once Union has advised Customer of the Checkpoint Variance, then Union, at any time prior to the Fall Checkpoint Date, upon three business days notification, shall have the right to refuse receipt of Gas until the BGA has been reduced by an amount equal to the Checkpoint Variance. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

If, by the Fall Checkpoint Date, a quantity of Gas greater than or equal to the Checkpoint Variance has not been disposed of, then Customer shall incur a charge equivalent to the difference between the Checkpoint Variance and the actual quantity disposed of by Customer after being notified of the Checkpoint Variance ("Union Determined Excess Quantity") multiplied by the Unauthorized Storage Space Overrun rate in Union's T1 Rate Schedule. The Unauthorized Storage Space Overrun rate will be applied to the remaining Union Determined Excess Quantity each month until the Union Determined Excess Quantity is reduced to zero.

In addition, Customer shall take immediate steps to dispose of the Union Determined Excess Quantity. On the first business day of October, or at any time afterwards, upon three business days notification, Union may refuse receipt of Gas until the BGA has been reduced by an amount equal to the Union Determined Excess Quantity. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

3.02 Service under the Customer Determined Balancing Option

Where Schedule 1 identifies the balancing option as "Customer Determined Balancing Option", Section 3.02 of this Schedule 2 shall apply and Section 3.01 shall not apply.

Under the Customer Determined Balancing Option, Customer is responsible for determining the quantity of Gas that must be supplied and executing the actions required to ensure that the actual BGA balance is greater than or equal to the Winter Checkpoint Quantity as of the Winter Checkpoint Date, and determining the quantity of Gas that must be disposed of and executing the actions required to ensure that the actual BGA balance is less than or equal to the Fall Checkpoint Quantity as of the Fall Checkpoint Date.

Winter Checkpoint

Periodically during the winter, Union will estimate what the BGA balance will be as of the Winter Checkpoint Date ("Winter BGA Balance") using recent third party weather forecasts, if applicable, and Customer's monthly consumption forecast. The BGA estimate will include estimated consumption, whether billed or unbilled, to and including the Winter Checkpoint Date. This information will be provided to Customer for information purposes only, and in no way limits or qualifies Customer's obligation to ensure that the actual BGA balance is greater than or equal to the Winter Checkpoint Quantity on the Winter Checkpoint Date. As the Winter BGA Balance is comprised of third party weather forecasts and Customer's consumption forecast, Union cannot make any representation or warranty as to the accuracy of the Winter BGA Balance.

If Customer determines that it requires a change in its supply arrangements to meet its Winter Checkpoint Quantity as of the Winter Checkpoint Date, Customer must, by the 15^{th} Business Day of February, request approval for a balancing transaction to deliver the additional Gas. If Customer does not make a request by the 15^{th} Business Day of February then Union is not obligated to accept the request if it cannot be reasonably accommodated or exposes Union to incremental costs.

If the actual BGA balance is less than the Winter Checkpoint Quantity on the Winter Checkpoint Date then Union will sell to Customer, and Customer will accept, a quantity of Gas equal to the difference between the actual BGA balance and the Winter Checkpoint Quantity, at the Banked Gas Purchase commodity charge in the R1 Rate Schedule.

Fall Checkpoint

During September, Union will determine and advise Customer on or about the 10th Business Day of September of the quantity of Gas projected to be in excess of the Fall Checkpoint in advance of the Fall Checkpoint Date ("Checkpoint Variance"). Once Union has advised Customer of the Checkpoint Variance, then Union, at any time prior to the Fall Checkpoint Date, upon three business days notification, shall have the right to refuse receipt of Gas until the BGA has been reduced by an amount equal to the Checkpoint Variance. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

If the actual BGA balance is greater than the Fall Checkpoint Quantity on the Fall Checkpoint Date, Customer shall incur a charge equivalent to the difference between the actual BGA balance and the Fall Checkpoint Quantity ("Customer Determined Excess Quantity") multiplied by the Unauthorized Storage Space Overrun rate in Union's T1 Rate Schedule. The Unauthorized Storage Space Overrun rate will be applied to the remaining Customer Determined Excess Quantity each month until the Customer Determined Excess Quantity is reduced to zero.

In addition, Customer shall take immediate steps to dispose of the Customer Determined Excess Quantity. On the first business day of October, or at any time afterwards, upon three business days notification, Union may refuse receipt of Gas until the BGA has been reduced by an amount equal to the Customer Determined Excess Quantity. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

3.03 Additional BGA Monitoring and Maintenance Obligations

In addition to meeting the Fall Checkpoint Quantity on the Fall Checkpoint Date and the Winter Checkpoint Quantity on the Winter Checkpoint Date above, Customer agrees to monitor its BGA balance on an ongoing basis, and shall maintain a BGA balance such that it does not exceed the Maximum Positive Variance or Maximum Negative Variance on the BGA Balancing Period Date(s) specified in Section 3 of Schedule 1. If Customer anticipates a BGA balance outside of any of these parameters then Customer shall promptly notify Union.

If Union forms the opinion that the BGA balance will exceed the Maximum Positive Variance at the end of a BGA Balancing Period Date as referenced in Section 3 of Schedule 1 then Union, in its discretion, shall have the right to refuse receipt of Gas.

Union's refusal to receive Gas under any circumstances described in this section does not relieve Customer of its obligation on any subsequent Day to deliver its Obligated DCQ to Union should Union require it. Union agrees to act in a reasonable and responsible manner when interpreting the relevant data for determining the forecasted BGA balances. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

3.04 Positive BGA Implications

In addition to planning and operating to balance to zero at the end of the Contract Year, Customer must take all actions required to ensure that the Maximum Positive Variance is not exceeded. On any BGA Balancing Period Date identified in Section 3 of Schedule 1, if the actual BGA balance is in excess of the Maximum Positive Variance ("Positive Variance Excess") then such excess shall incur a charge equivalent to the Unauthorized Storage Space Overrun rate in Union's T1 Rate Schedule. The Unauthorized Storage Space Overrun rate will be applied to the remaining Positive Variance Excess each month until the Positive Variance Excess is reduced to zero.

In addition, Customer shall take immediate steps to dispose of the Positive Variance Excess. On the first business day of the month following the BGA Balancing Period Date identified in Section 3 of Schedule 1, or at any time afterwards, upon three business days notification, Union may refuse receipt of Gas until the BGA has been reduced by an amount equal to the Positive Variance Excess. Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of refusing receipt of Gas.

3.05 Negative BGA Implications

In addition to planning and operating to balance to zero at the end of the Contract Year, Customer must take all actions required to ensure that the Maximum Negative Variance is not exceeded. On any BGA Balancing Period Date identified in Section 3 of Schedule 1, if the actual BGA balance is in excess of the Maximum Negative Variance then the excess shall be sold by Union and purchased by Customer at the Banked Gas Purchase charge in the R1 Rate Schedule.

3.06 Energy Conversion

Balancing of receipt by Union with distribution to Customer is calculated in energy. The distribution to Customer is converted from volume to energy using Union's standard practices.

3.07 Disposition of Gas at Contract Termination

If this Contract terminates or expires and Customer does not have a contract for Storage Services with Union then, except as authorized by Union, no positive BGA balance shall be allowed. Unless otherwise agreed to by Union, any positive BGA balance remaining in Customer's BGA as of such date of termination or expiry shall incur a charge equivalent to the Unauthorized Storage Space Overrun rate in Union's T1 Rate Schedule. Customer shall incur such charge until the balance has been reduced to zero.

Unless otherwise agreed to by Union, any negative BGA balance as of the date of termination shall be sold by Union, and purchased by Customer, at the Banked Gas Purchase commodity charge in the R1 Rate Schedule.

3.08 BGA Carryover Limitation During Late Season Injection

If the current Contract Year ends during the period September 15 to November 15, Union will provide Storage Services for a positive BGA balance on a reasonable efforts basis only. If in Union's opinion such Service is not available, Customer, when requested by Union, shall reduce deliveries to Union to ensure that the positive balance is reduced to zero or to an amount specified by Union. Such request by Union shall release Customer from its Obligation to deliver during the period specified. Any Gas in excess of the amount specified by Union shall incur a charge equivalent to the Unauthorized Storage Space Overrun rate in Union's T1 Rate Schedule.

4 CHANGES TO CONTRACT PARAMETERS (SCHEDULE 1)

4.01 General Service Class

This Section 4.01 shall only apply to Contracts that do not have any end use locations served under rates M4, M5, M6, M7 or M9. Any changes to the list of End Use locations, consumption patterns, or upstream supply may have a corresponding change to the parameters in Schedule 1 as determined by Union. If there is a change, Customer will receive a revised Schedule 1 from Union prior to the effective date of the change. If Customer does not acknowledge and agree to the revised Schedule 1 in writing at least 25 days prior to the effective date of the change then the Contract will be terminated.

4.02 Contract Rate Classes

This Section 4.02 shall only apply to Contracts with one or more end use locations served under rates M4, M5, M6, M7 or M9. The monthly consumption estimates and the monthly Gas supply are used to determine the Fall and Winter Checkpoints. If Customer has not provided Notice for termination in accordance with the Notice provisions of the Contract, then the parameters in Schedule 1 shall apply to the next Contract Year. However, during the period prior to 25 days before the beginning of the next Contract Year, Union and Customer agree to negotiate in good faith new Schedule 1 parameters reflecting Customer's expected consumption profile for the next Contract Year. If the parties cannot reach agreement, then the existing parameters shall apply.

5 CUSTOMER'S FAILURE TO DELIVER GAS

5.01 Customer's Failure To Deliver Obligated DCQ to Union

If on any Day, for any reason, including an instance of Force Majeure, Customer fails to deliver the Obligated DCQ to Union then such event shall constitute a "Failure to Deliver" and the Failure to Deliver rate in the R1 Rate Schedule shall apply to the quantity Customer fails to deliver. The upstream transportation costs (if any) (Section 1) shall also apply and be payable by Customer.

For Gas that should have been received, Union may make reasonable attempts, but is not obligated to acquire an alternate supply of Gas. For greater certainty, payment of the Failure to Deliver charge is independent of and shall not in any way influence the calculation of Union's costs and expenses associated with acquiring the said alternate supply of Gas.

In addition to any rights of interruption in the Gas Distribution Contract(s), Union may immediately suspend distribution of Gas to the Consumption Points or Union may direct Customer to immediately curtail or cease consumption of Gas at the Consumption Points.

Customer shall immediately comply with such direction. Such suspension or curtailment shall not constitute an Interruption under the Gas Distribution Contract(s).

Union shall not be liable for any damages, losses, costs or expenses incurred by Customer as a consequence of Union exercising its rights under this Section.

5.02 Notice Of Failure

Each Party shall advise the other by the most expeditious means available as soon as it becomes aware that such failure has occurred or is likely to occur. Such notice may be oral, provided it is followed by written Notice.

5.03 Customer Failure To Deliver Compressor Fuel

For Gas to be delivered by Customer to Union at an Upstream Point of Receipt, if Customer fails to deliver sufficient Compressor Fuel then, in addition to any other remedy, Union shall deem the first Gas received to be Compressor Fuel and Section 5.01 will apply.

Exhibit "C"

UNION GAS LIMITED

Answer to Interrogatory from
Natural Resource Gas Limited

Reference: History of the Application of the Penalty Rate at $78.73 per GJ

Has Union previously imposed a penalty charge as high as $78.73 per GJ on T1/T2, Rate 25 or Bundled T customers and, if so, on what circumstances and what was the total amount of each imposition of penalty charge? Has Union ever granted any relief or exception to the imposition of a penalty charge which was otherwise consistent with its rate schedules or contracts? If so, on what grounds? Can Union provide the last 10 years for check point months, the amount of the penalty/GJ as opposed to the commodity price/GJ per the QRAM in place at that time? The amount of GJ's during those years for which a penalty was applied for DP customers on checkpoint? What percentage of total DP customers and volumes were charged this penalty? Penalty related to checkpoint only.

Response:

Union has not previously imposed a charge as high as $78.73 per GJ.

Union has previously granted relief or exception to a charge. The penalty most typically waived is the late payment penalty, such as when a customer established payment arrangements with Union. Exception has also been provided when a metering or reporting issue caused the customer to have incomplete usage information and inadvertently exceeded their contract parameters. Union has also provided exception for high credit risk customers in order to avoid a bad debt situation. Further to this last example, and as noted in Exhibit B.Staff.1 part c), Union is requesting this one-time exemption based on feedback from customers most impacted by the penalty charge, including potential financial impairment or bankruptcy.

Using best available information back to 2006, Table 1 shows pricing, volumes, charges and compliance rates (volumetric and customer).

This is Exhibit "C" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 20 15

A COMMISSIONER FOR TAKING AFFIDAVITS

Table 1
Analysis of February Checkpoint Activity 2006 - 2014

Year	Ontario Landed Reference Price	February Penalty Rate $/GJ	Volume Shortfall GJ	Volumetric Compliance Rate	Total Billed Charges	No of Customers	Customer Compliance Rate
2006	$12.45	$12.45	6,266	98%	$78,024	7	99%
2007	$9.33	$9.33	16,872	99%	$157,399	5	99%
2008	$8.18	$9.87	52,006	96%	$513,299	16	98%
2009	$9.32	$9.32	95,160	96%	$886,796	25	96%
2010	$6.81	$6.81	17,087	99%	$116,277	9	99%
2011	$5.37	$5.37	15,939	99%	$85,592	7	99%
2012	$5.39	$5.39	10,811	98%	$58,228	8	99%
2013	$5.57	$5.57	23,155	99%	$128,881	8	99%
2014	$4.87	$78.73	55,339	99%	$4,356,727	11	98%

- Ontario Landed Reference Price per QRAM in effect for the month of February of each year.
- February Penalty Rate is the higher of the daily spot cost at Dawn in the month of or the month following the month in which gas is sold, but not be less than Union's approved weighted average cost of gas.
- Volume Shortfall is the amount of gas sold to customers.
- Volumetric Compliance Rate is the Volume Shortfall divided by the total volume of gas to be delivered by customers to meet their checkpoint obligations.
- Total Billed Charges is February Penalty Rate multiplied by the Volume Shortfall.
- Number of Customers is the count of customers that incurred a Volume Shortfall.
- Customer Compliance Rate is the Number of Customers divided by the total number of active contracts in February of each year.

Exhibit “D”

NAVIGANT

ENERGY

Ontario Energy Board

2014 Natural Gas Market Review

Stakeholder Conference

Emerging Trends and Outlook for the North American Natural Gas Market – Session 4 / Panel 1

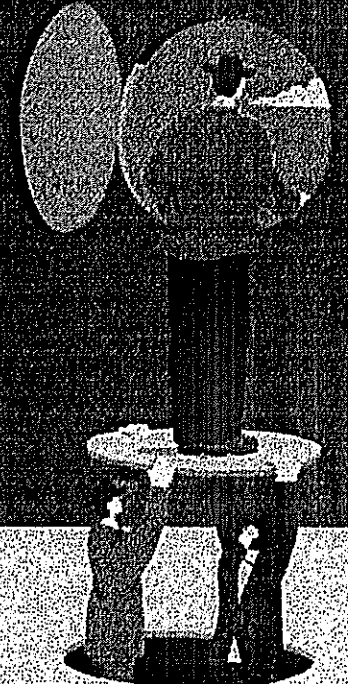
Ontario Energy Board

2300 Yonge Street, 25th Floor

Toronto, Ontario M4P 1E4

West Hearing Room / ADR Room

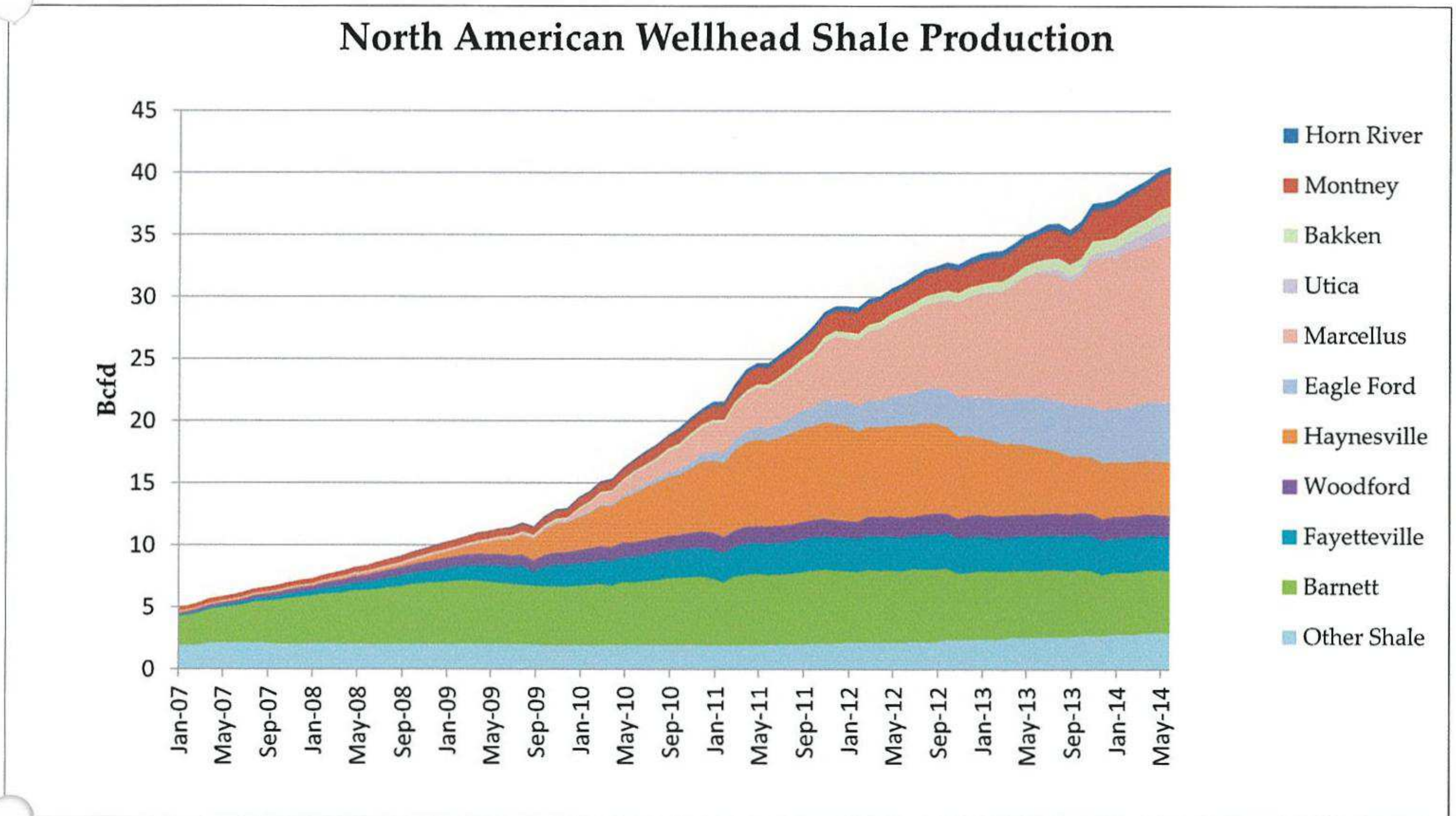
December 3-4, 2014



This is Exhibit "D" referred to in the affidavit of Brian Lippold sworn before me, this 25 day of March 2015

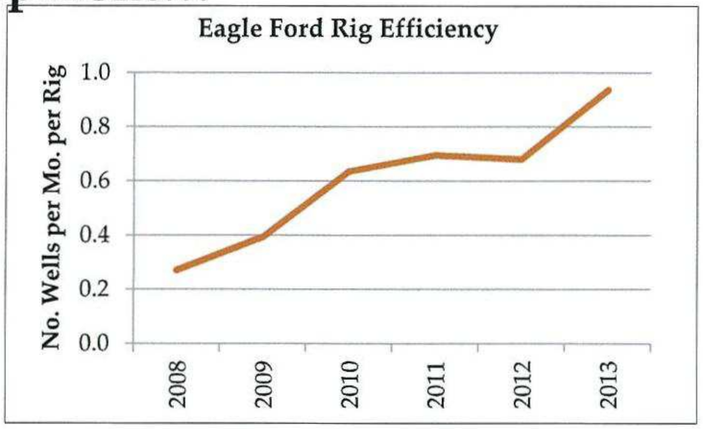
A COMMISSIONER FOR TAKING AFFIDAVITS

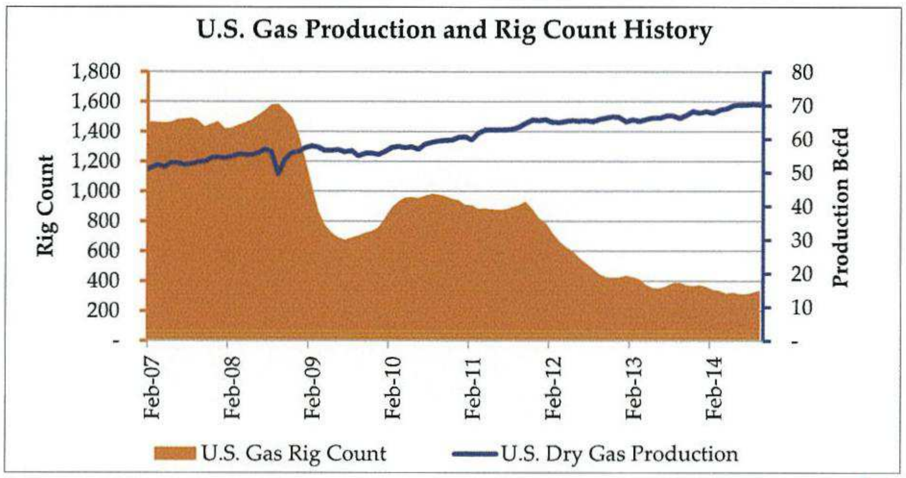
The key current trend in the natural gas market is the continuing growth in shale gas production…



NAVIGANT
ENERGY

Which has occurred in tandem with increasing efficiency in shale gas development…





NAVIGANT
ENERGY

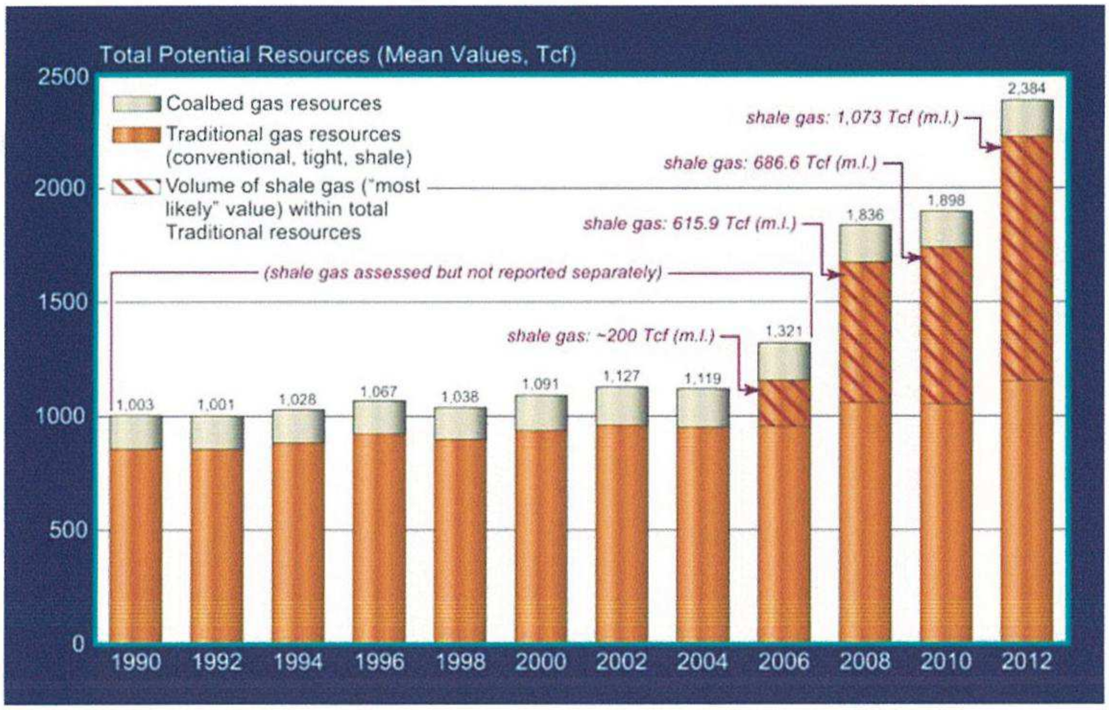
Shale Production Has Increased On Cost Improvements Primarily from Horizontal Drilling

Key Factors to Lower Unit Costs of Production Have Been:

- Proliferation of pad drilling
- Longer laterals
- More efficient 'walkable' rigs
- Advanced completion techniques
- Better fracking 'recipes'
- Better 'geo' intelligence of the resource base

As well as increasing estimates of shale gas resources.

U.S. Natural Gas Resource Estimates by the U.S. Potential Gas Committee



NAVIGANT
ENERGY

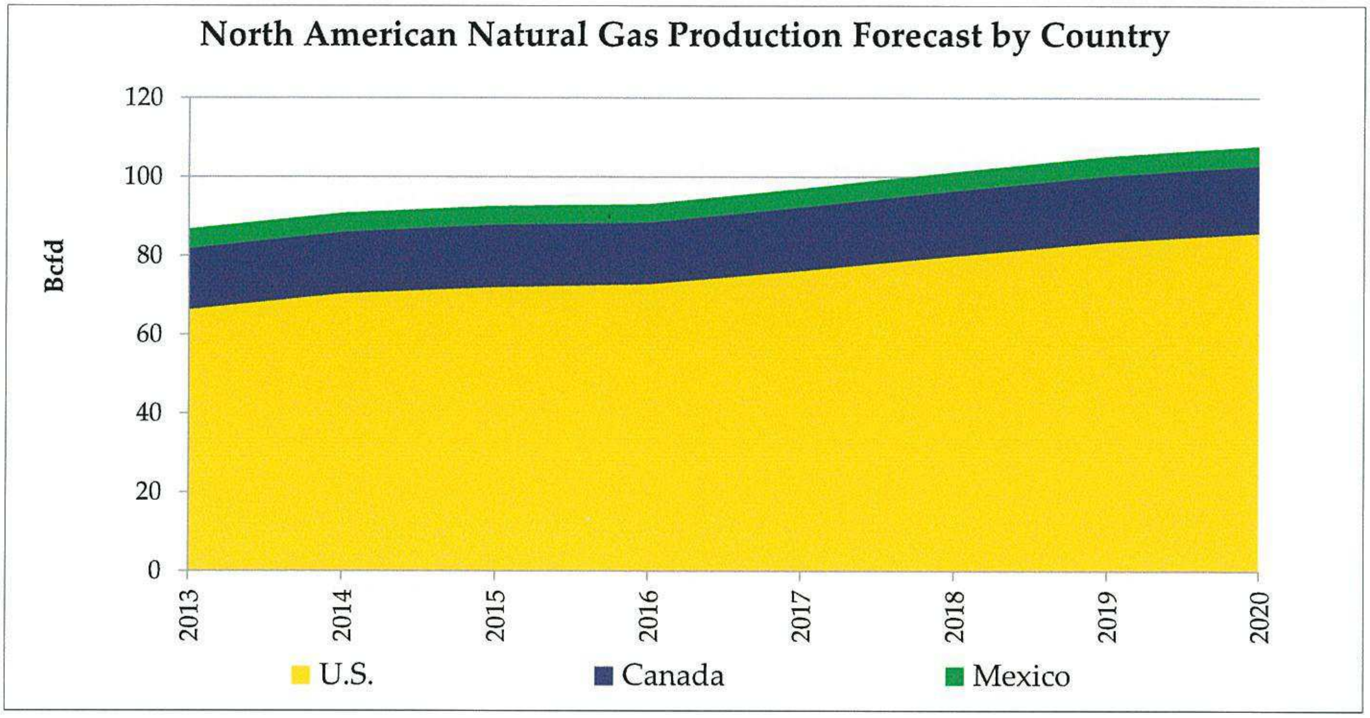
These increasing estimates of natural gas resources support an estimated North American resource life of almost 150 years. Almost 400 years in Canada.

	Natural Gas Resource				
	Conventional (Tcf)	Unconvent'l (Tcf)	Total (Tcf)	Demand (Tcf)	Resource Life (Years)
Canada	422	1,022	1,444	3.7	392
U.S.	1,458	1,231	2,689	26.1	103
Mexico	-	545	545	2.3	242
North America	1,880	2,798	4,678	32.1	**146**

Sources: U.S. E.I.A. Assessment; NEB Energy Future 2013; Navigant forecast; Potential Gas Committee

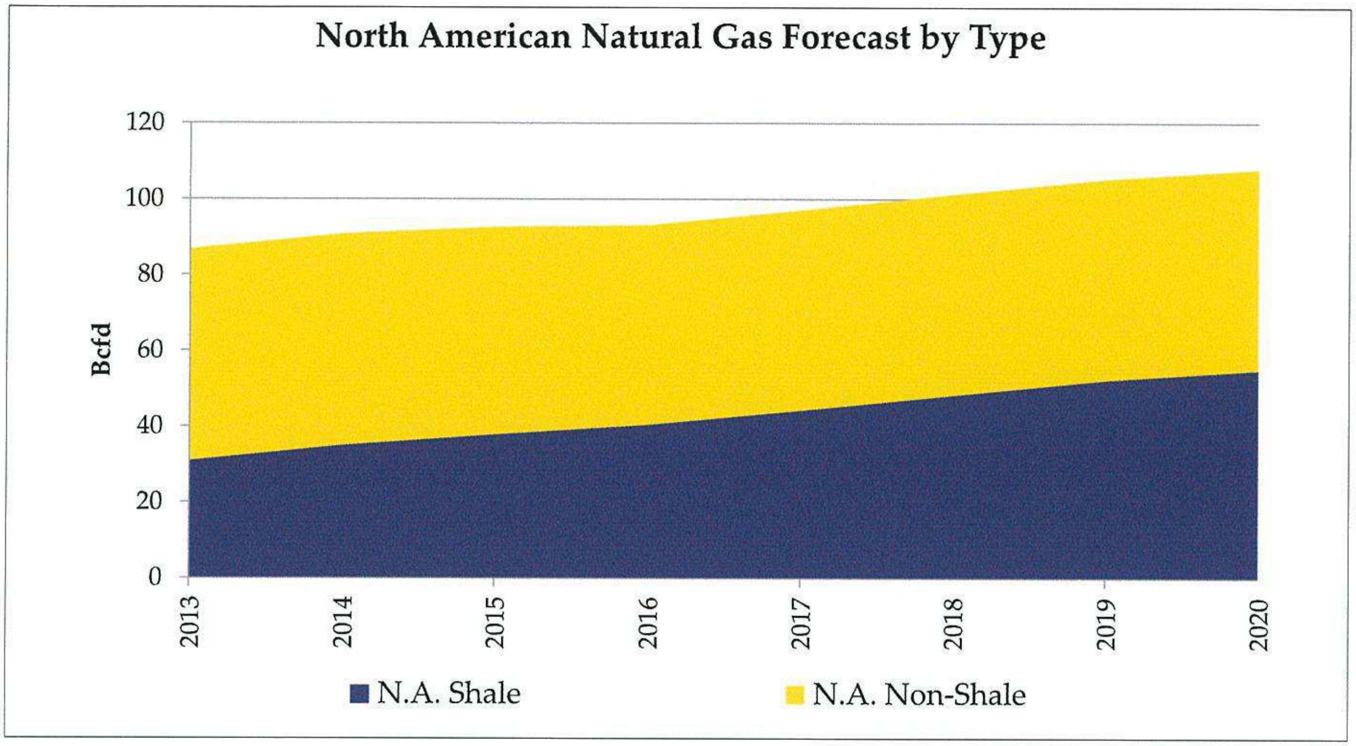
NAVIGANT
ENERGY

The ample North American gas resource base supports Navigant's outlook of strong production growth in North America.



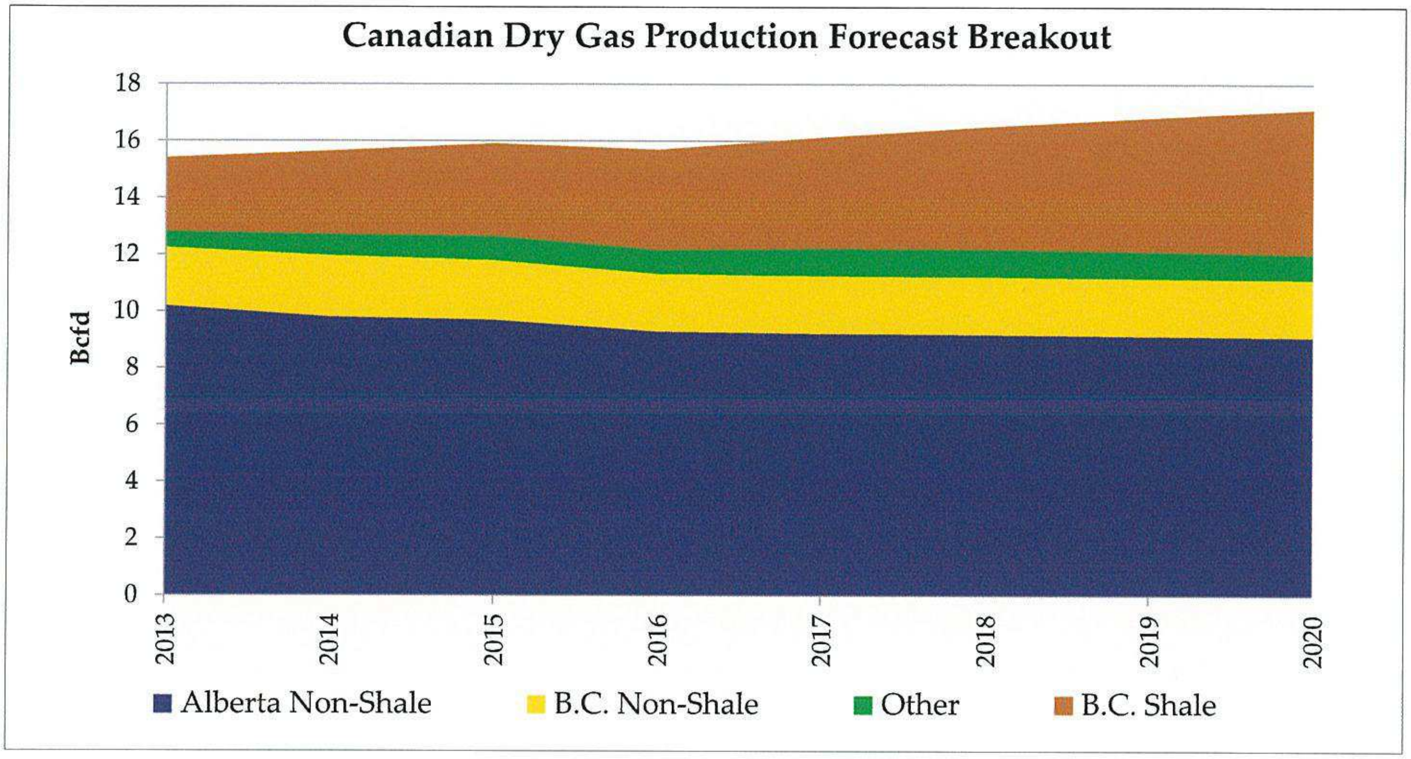
NAVIGANT
ENERGY

North American gas production growth is driven by shale gas. Ample resource + low costs to produce = increasing production



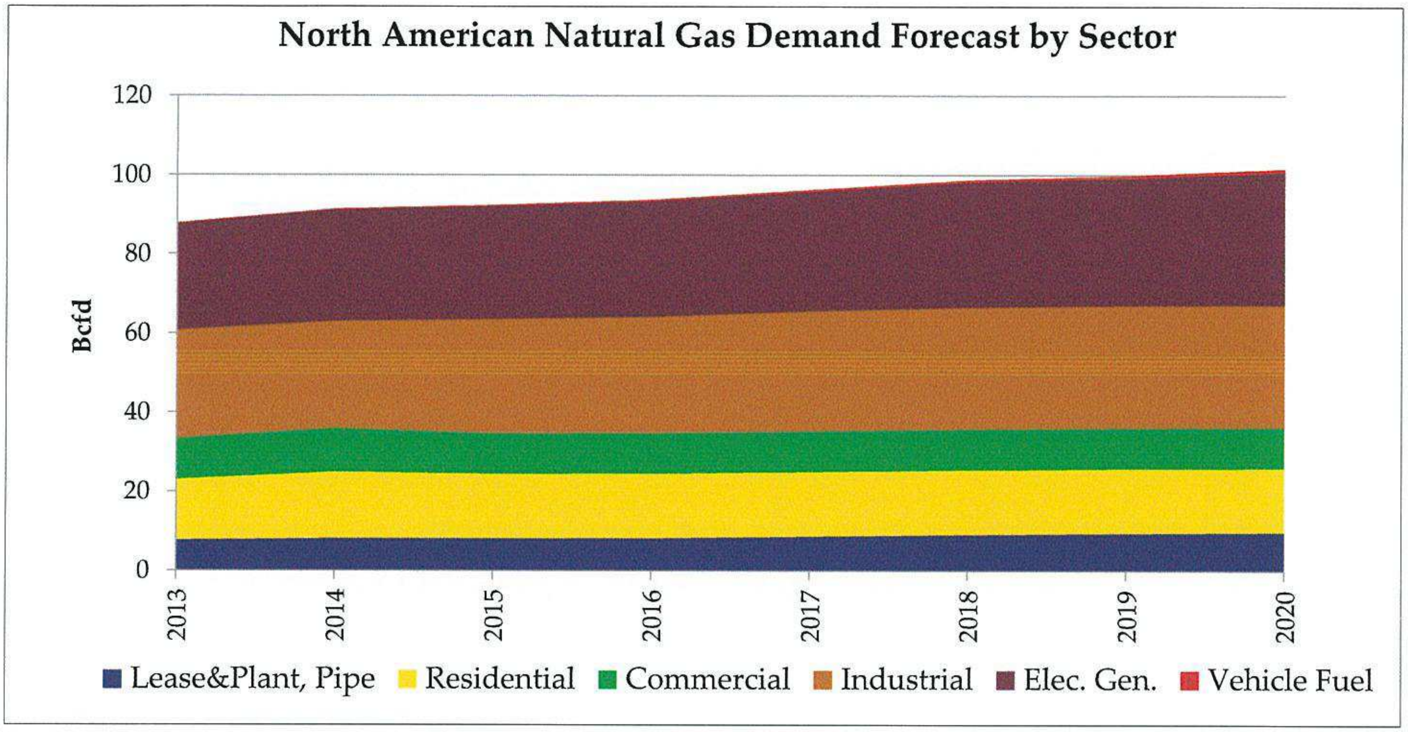
NAVIGANT
ENERGY

Canadian natural gas production will increase, with B.C. shale production outpacing non-shale declines in Alberta.



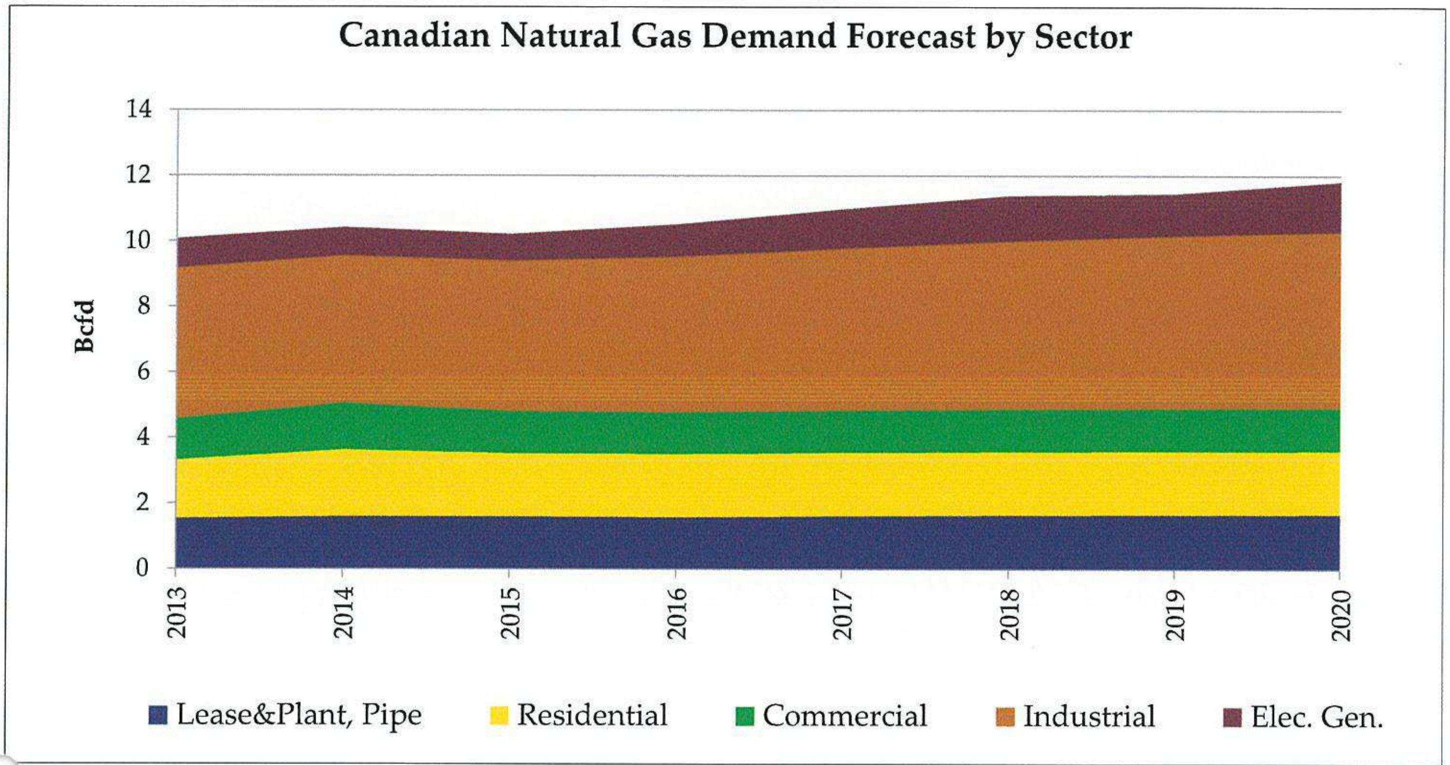
NAVIGANT
ENERGY

North American natural gas demand growth will be driven by the electric generation and industrial sectors.



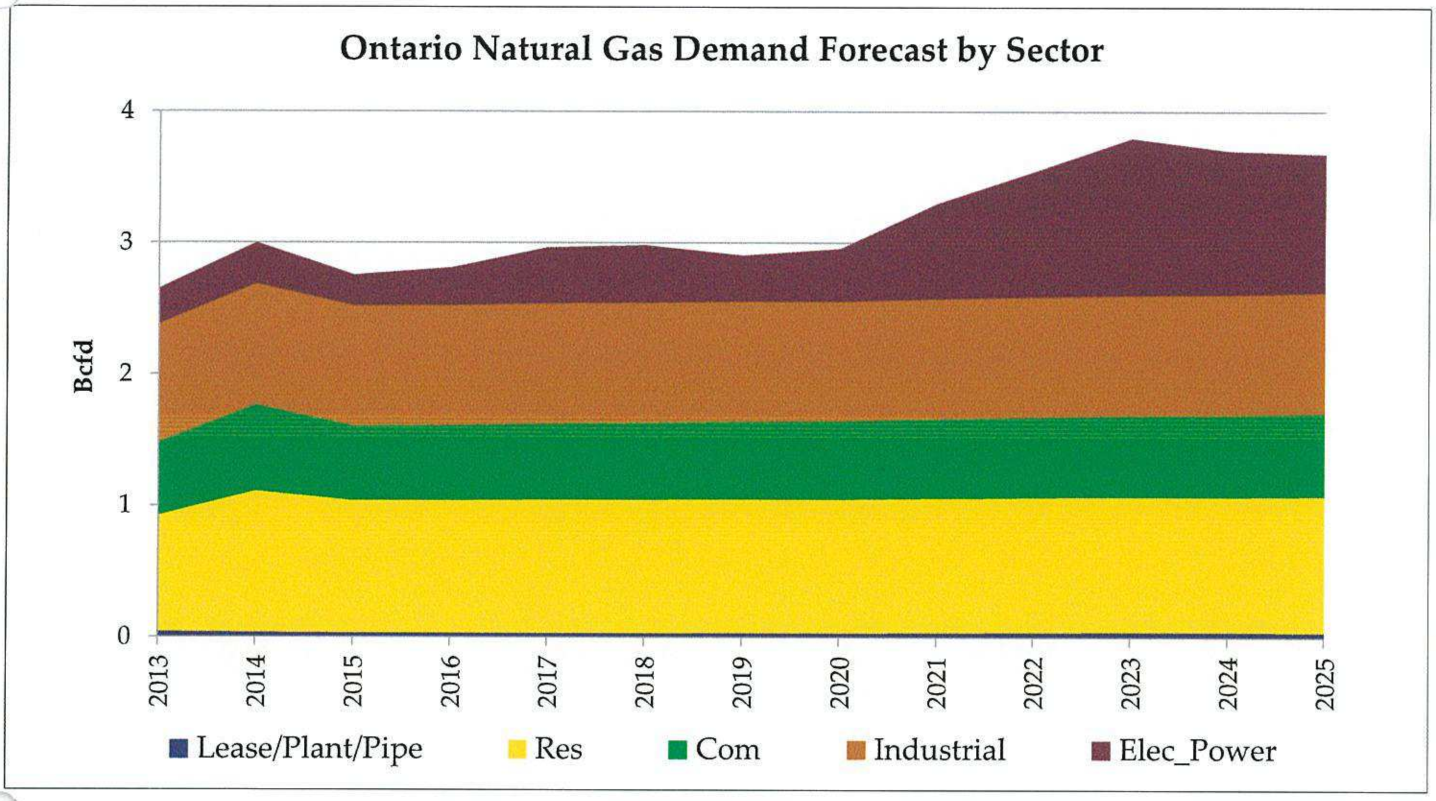
NAVIGANT
ENERGY

Canadian natural gas demand growth will be driven primarily by the industrial sector (AB oilsands)



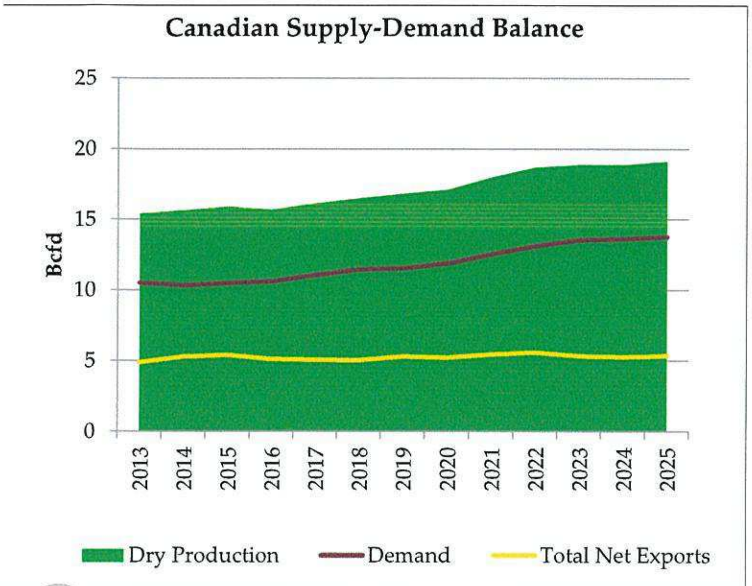
NAVIGANT
ENERGY

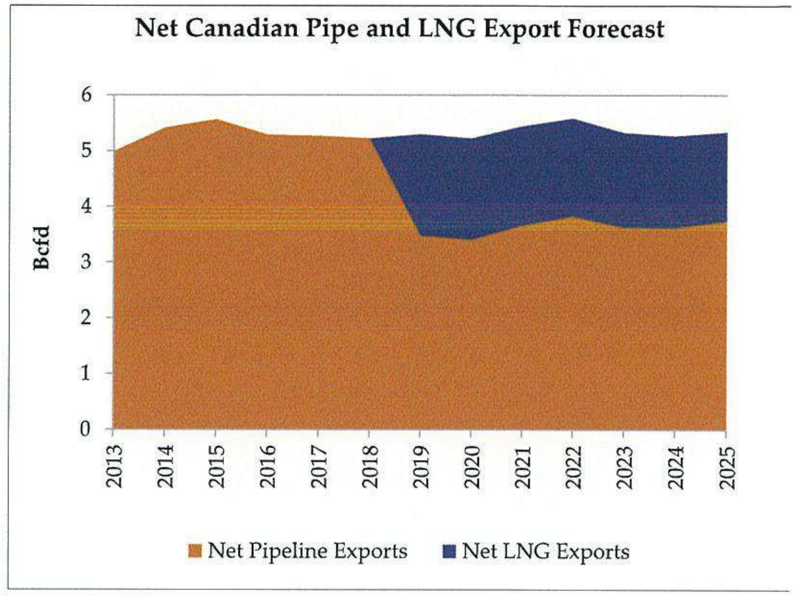
Ontario natural gas demand growth will be driven by increases in gas-fired electric generation.



NAVIGANT
ENERGY

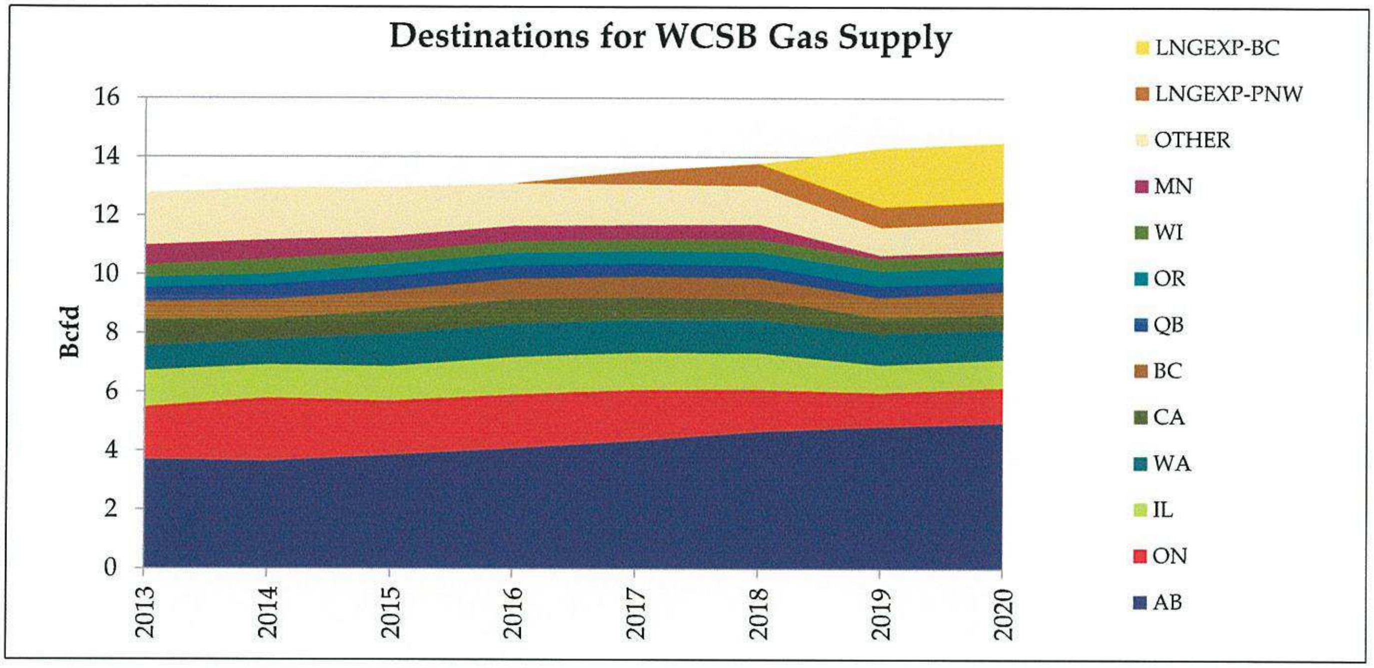
The forecast supply-demand balance for Canada reflects over 5 Bcfd of pipe or LNG exports, an average of about 30 percent of production for export – pipe and LNG export.





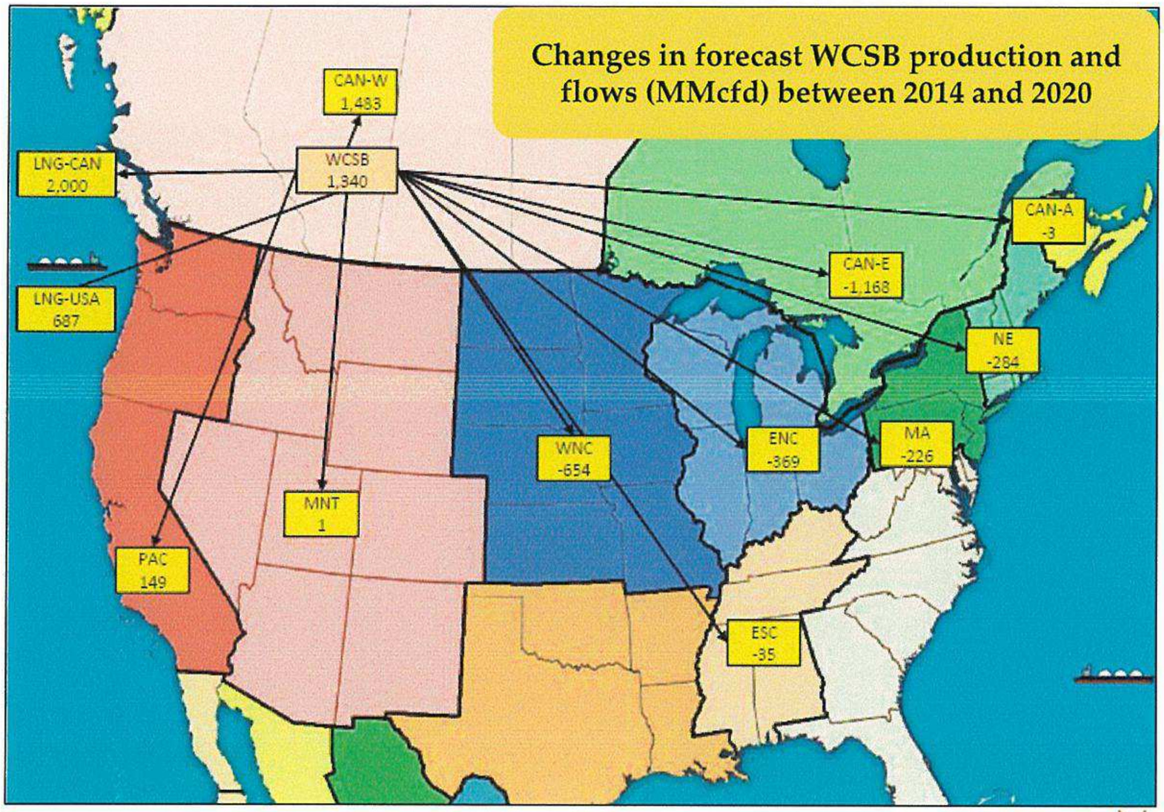
NAVIGANT
ENERGY

Navigant's outlook for WCSB supplies includes a decrease in shipments to meet Ontario demand, as well as new shipments to a new market in LNG exports from the west coast of North America.



NAVIGANT
ENERGY

As expected increases in WCSB production occur, they will be increasingly meeting western Canadian demand increases, western U.S. demand, and potential LNG exports.

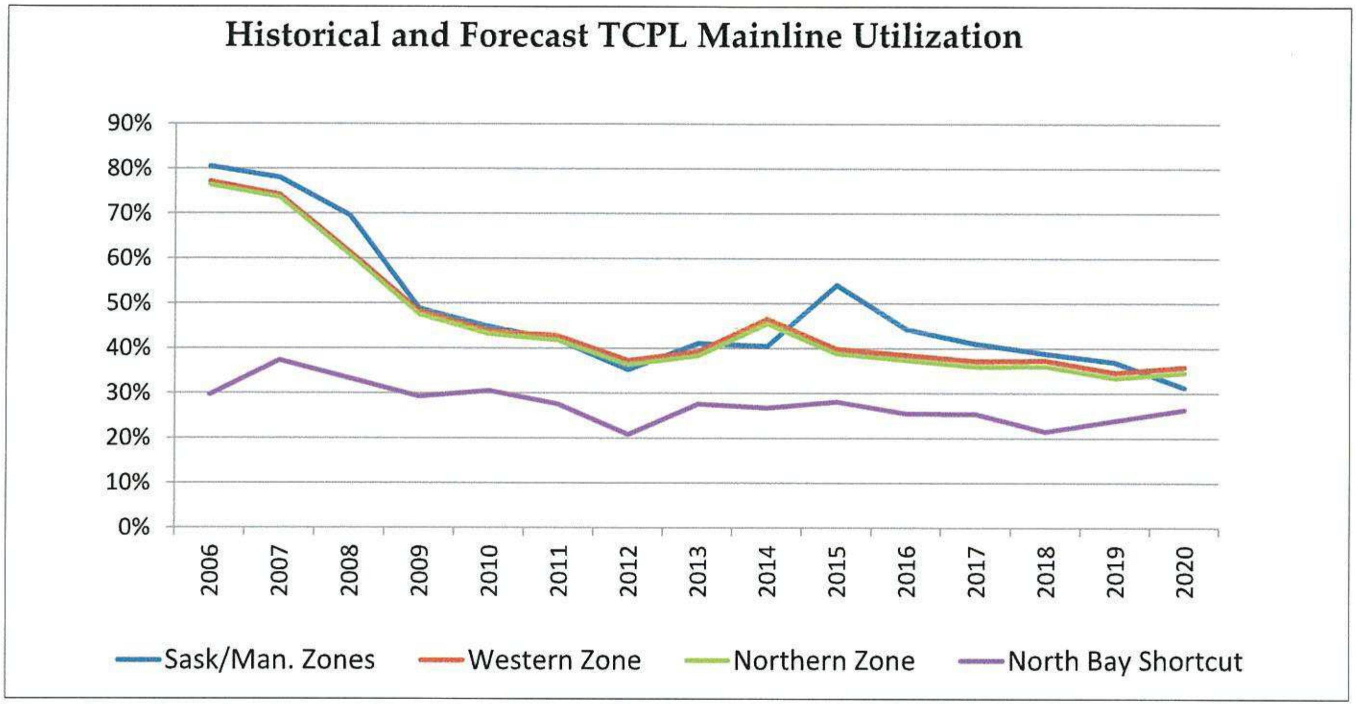


NAVIGANT
ENERGY

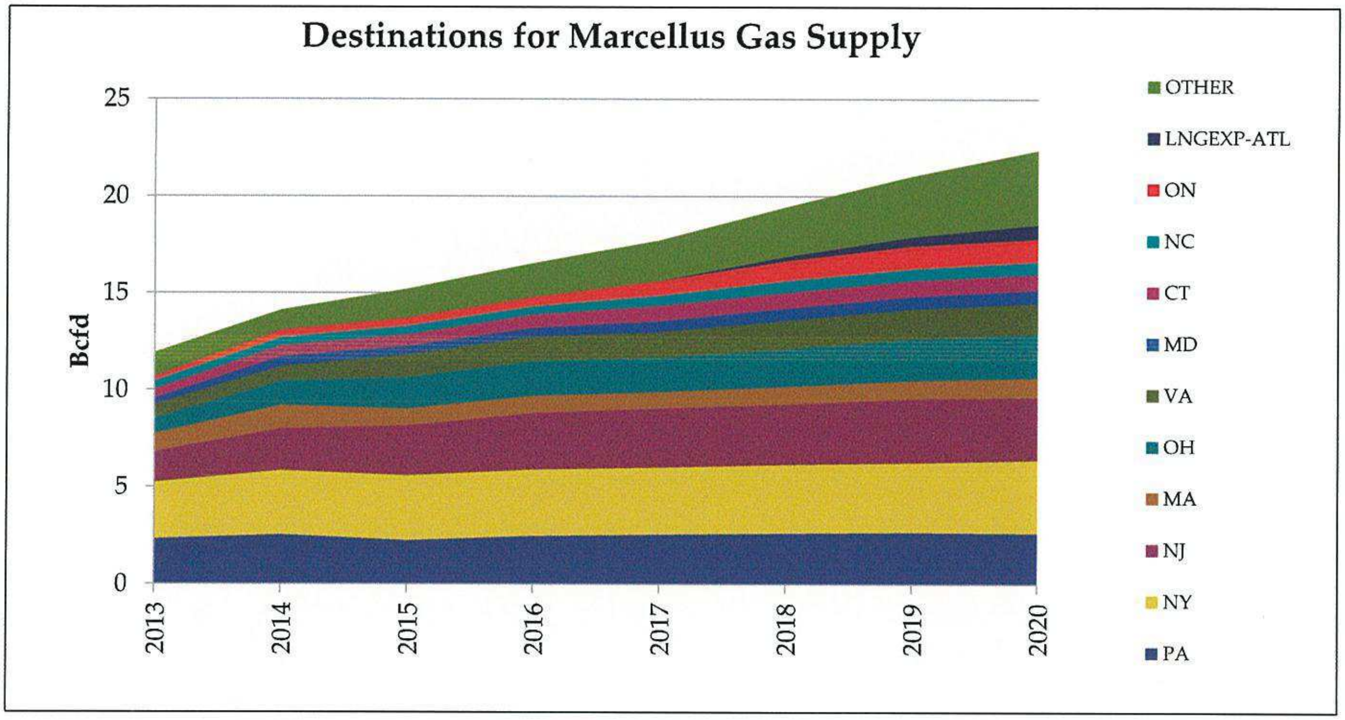
While there are many proposed LNG export projects, Navigant expects that a realistic build-out will be about 10 Bcfd from North America.

NAVIGANT
ENERGY

The decreased eastward deliveries from the WCSB are reflective of expected continued decreased flows on the TCPL Mainline – all zones

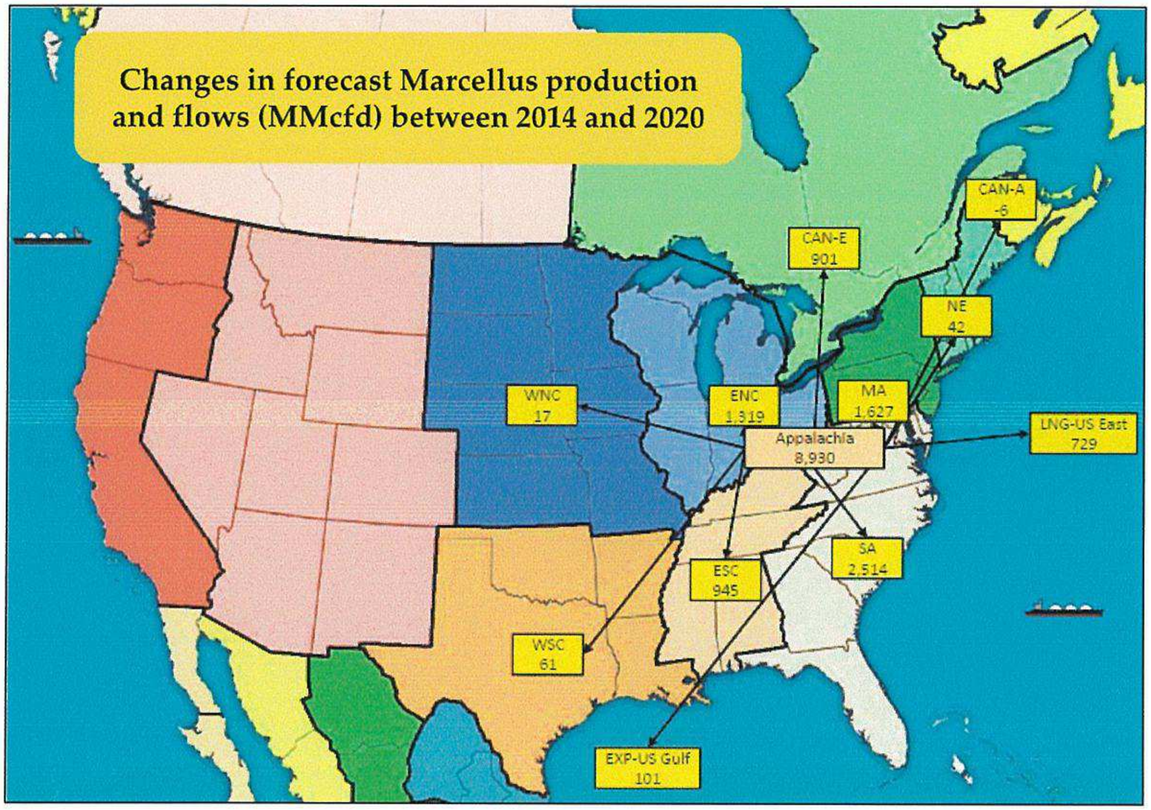


And the increasing importance of Marcellus production to the North American gas market…



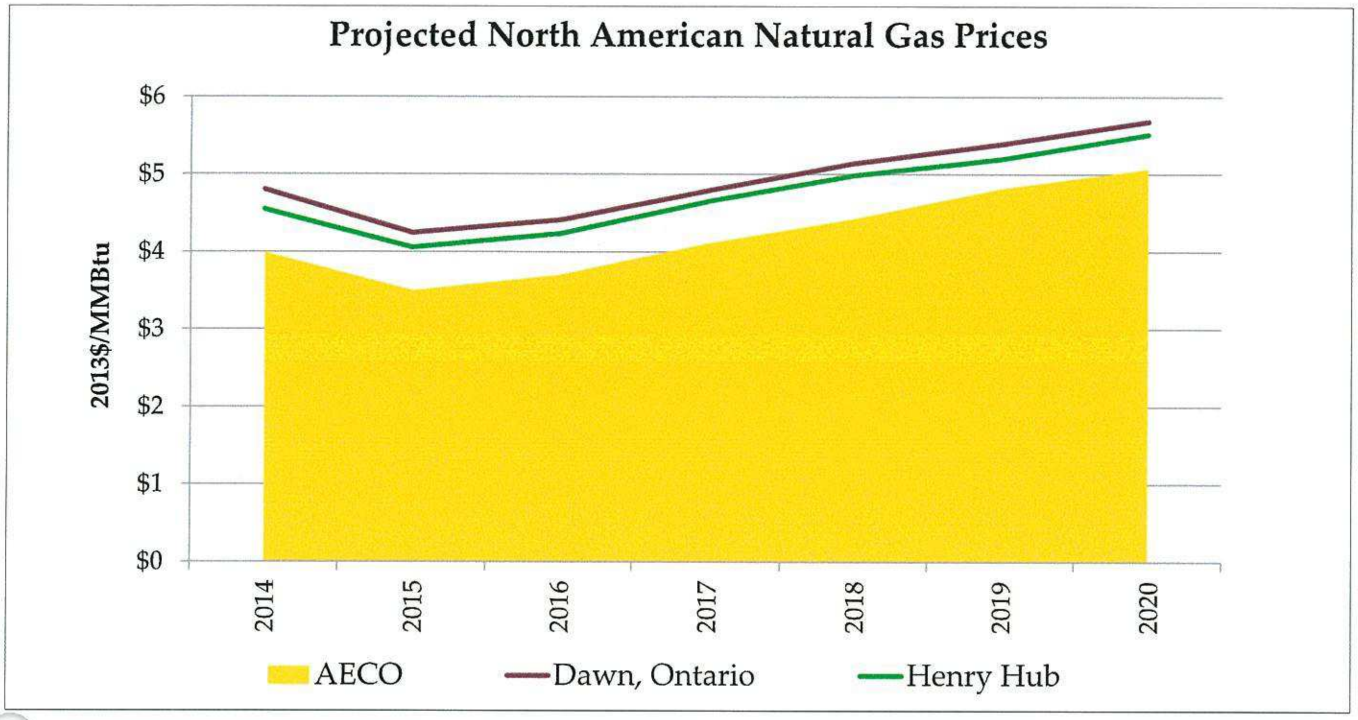
NAVIGANT
ENERGY

Where Marcellus supplies are forecast to become an important part of supplies across eastern North America by 2020 (and westward thereafter).



NAVIGANT ENERGY

North American gas prices are forecast to be reasonable and competitive over the forecast period



NAVIGANT
ENERGY

Canadian Regulatory - Infrastructure

- **TCPL Mainline Rate Restructuring (RH-003-2011)** – while the key tenets of the TCPL 'restructuring proposal' were denied by the NEB, in the decision the NEB set tolls for firm service through 2017 at lower rates but allowed TCPL discretion for IT and short-term service. In Winter 2013-14, the result was some IT and short term rates were sold at high market prices by TCPL as demand increased.
- **TCPL Mainline - Energy East Conversion** – a proposal by TCPL to convert mainline gas transport capacity to 'oil' transport service. As planned the $11.3 Billion project ($380 million in Ontario) would have a capacity of 1.1 million Barrels per day of oil transport capacity for delivery to refineries in Quebec and New Brunswick beginning in 2017. Given existing and forecast capacity on the 'mainline' and other market developments, it is Navigant's view that the project will have minimal impact on Ontario. Additional modeling to be done, will attempt to confirm this for the OEB.
- **TCPL Eastern Mainline Project** – TCPL in May 2014 filed a proposal to add up to 250 kms of new 36" pipeline and compression on the mainline as a result of the Energy East project from Markham, Ontario to South Dundas in Eastern Ontario. Project cost – C$1.5 Billion and will have a capacity of 600 MMcfd.
- **NEB Approved TCPL Tolls and Tariff Decision** (November 28/14) – as established in the Mainline Restructuring Decision, the NEB approved the settlement by Enbridge, Union and Gaz Metro and TCPL for tolls between 2015-2020.

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NAVIGANT
ENERGY

Exhibit “E”

NAVIGANT

Winter 2013/14 Natural Gas Price Review

Prepared for:

Ontario Energy Board

Ontario Energy Board

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Bay Adelaide Centre
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(416) 777-2440
www.navigant.com

November 25, 2014

This is Exhibit "E" referred to in the affidavit of Brian Lippold sworn before me, this 25 day of March 2015

A COMMISSIONER FOR TAKING AFFIDAVITS

NAVIGANT

Winter 2013/14 Natural Gas Price Review

Glossary

Checkpoint balancing	A balancing requirement on Union Gas' direct purchase customers requiring a particular minimum balance to be in a customer's Banked Gas Account as of the Winter Checkpoint Date of February 28.
Dawn, Ontario	The major gas market and storage center serving southwestern Ontario
Eastern Canada	A division used to account for storage locations in Canada, including the areas east of the Saskatchewan-Manitoba border
Eastern U.S.	A division used to account for storage locations in the U.S., including the states of the U.S. east of the Mississippi River, but including IA, MO, and NE and excluding AL and MS
Empress	The point at the Alberta-Saskatchewan border where the TCPL Mainline begins
Enbridge	Enbridge Gas Distribution, the gas distribution utility serving much of Toronto and environs
FT	Firm Transportation of natural gas under utility tariff from a receipt point to a delivery point for a specified maximum capacity for a term over one year
HDD	Heating Degree Days, a measure equal to the number of degrees that a day's average temperature is below 18 degrees Celsius
IT	Interruptible Transportation of natural gas under utility tariff providing for curtailment for capacity and/or supply reasons, at the utility's option
LDC	Local Distribution Company, a retail gas distribution utility
QRAM	The Quarterly Rate Adjustment Mechanism that allows Ontario's gas distribution utilities to recover their gas supply costs via customer rates
STFT	Short-Term Firm Transportation for a term between 7 days up to one year, with less flexible terms than FT
STS	Storage Transportation Service allows for injections and withdrawals at storage locations, held in conjunction with an FT contract
TCPL	TransCanada Pipeline, which includes the Mainline
U.S. Region-East North Central	The U.S. states MI, OH, IN, IL, WI
U.S. Region-East South Central	The U.S. states KY, TN, AL, MS
U.S. Region-Middle Atlantic	The U.S. states NY, NJ , PA
U.S. Region-Mountain	The U.S. states MT, ID, WY, CO, UT, NV, AZ, NM
U.S. Region-New England	The U.S. states ME, VT, NH, MA, CT, RI
U.S. Region-Northeast	The U.S. states in the Middle Atlantic and New England
U.S. Region-Pacific	The U.S. states WA, OR, CA

U.S. Region-South Atlantic	The U.S. states WV, MD, DE, VA, NC, SC, GA FL
UDC	Unabsorbed Demand Charges, reflecting a utility's costs for unutilized firm transport capacity
Union Gas	Union Gas, Ltd., the gas distribution utility serving northern Ontario and parts of southwest Ontario

1. Executive Summary

The Ontario Energy Board (Board) engaged Navigant Consulting to analyze the gas market events of last winter, focusing on the variables and factors that affected Ontario natural gas supply, demand and prices over the Winter 2013/14 period, and to identify potential prospective issues relative to such factors affecting prices.

Extreme winter conditions associated with last winter's polar vortex[1] events elevated natural gas demand throughout the U.S. and Ontario to record levels. As a result of dramatically elevated natural gas demand levels that occurred over an extended period of time and over a widespread geographic area, spot natural gas prices were elevated across most market points of North America for at least some period of the winter. Prices at the Dawn market hub were elevated mostly during February, with a few spikes in January and some residual price elevation in early March. These market conditions also set the stage for additional factors that further exacerbated Ontario gas prices

There were many events unfolding in real time last winter as market participants made decisions on planning and acquiring supply. The most important event was the cold weather, which was widespread, persistent, and extreme. Hindsight allows all the information to be seen at once. Following are the main conclusions about last winter's gas prices and the various events that contributed to them:

- Extreme winter conditions elevated natural gas demand throughout the U.S. and Ontario to record levels, leading to a tight gas market and setting the stage for additional factors that exacerbated the winter's price behavior.
- Strong Midwest demand impacted gas prices at Dawn and incented increased storage withdrawals to meet Ontario demand.
- Large storage withdrawals early necessitated large spot purchases later (which happened to be at high prices) as continued cold conditions led to persistent high demand.
- "Checkpoint" balancing by Union direct purchase customers, although an annual occurrence, coincided last winter with the on-going need to meet persistent high demand, exacerbating prices.
- Increased interruptible transport tolls appear to have limited the competitiveness of Empress as an economic source of supply, leading incremental gas for Ontario to be drawn from the Midwest and Northeast, further exacerbating Dawn prices
- The necessary conditions for last winter's price scenario appear to be the coincidence in both the U.S. and Canada of early, widespread and persistent high demand (resulting from the macro weather conditions).
- It is not clear whether the same weather conditions would have led to the same price impacts had supply plan requirements called for more base storage or increased firm transportation, but more storage and increased firm transportation may have helped.
- Similarly, supply plan requirements leading to more conservative use of storage withdrawals (and thus more supply procurement early in the winter) would likely have helped.

[1] "Polar vortex" refers to a type of event, one of which occurred from December 2013 through April 2014, where there is a southward shift of the North Polar Vortex, which is a cyclonic wind pattern in the upper atmosphere in the North Pole region.

Navigant also reviewed the drivers of the Quarterly Rate Adjustment Mechanism (QRAM), the provinces's mechanism to allow gas distributors to recover their actual gas costs. As the QRAM relates to actual gas supply costs, the drivers of the QRAM are essentially the factors that influence a gas distribution company's actual gas costs. Such factors that could potentially be impacted by operational, managerial and regulatory policies, procedures, directives and decisions of a gas distribution company or its regulator include the following: weather assumption design day criteria, demand forecasts, firm transportation planning criteria, storage level planning, use of peaking supplies, and procurement mechanisms for incremental supply. Choices made with respect to these factors likely involve cost and risk trade-offs dependent on an entity's risk profile and the array of potential risks.

2. Explanation of 2013/2014 Winter Price Levels and Volatility-

a. Introduction

It is important to remember that the Ontario natural gas market is part of the larger, highly-integrated and interconnected North American natural gas market, which is distinct in the world for its efficiency and transparency that allow for a highly competitive market environment. As such, the market will largely drive the particular impacts of events such as a cold winter based on supply and demand. As supply resources and the infrastructure necessary to move new supplies to demand centers continue to develop, we would expect that market responses to cold weather events would evolve, as well.

Extreme winter conditions associated with last winter's polar vortex events elevated natural gas demand throughout the U.S. and Ontario to record levels. As a result of dramatically elevated natural gas demand levels that occurred over an extended period of time and over a widespread geographic area, spot natural gas prices were elevated across most market points of North America for at least some period of the winter. Prices at the Dawn market hub were elevated mostly during February, with a few spikes in January and some residual price elevation in early March. These market conditions also set the stage for additional factors that further exacerbated Ontario gas prices, as explained in Section 2.e.

The key price effect in Ontario was the sustained and increasing price trend that occurred in February. Due to the higher actual prices paid than were forecast, and larger than forecast purchased gas supplies by Ontario's major gas Local Distribution Companies (LDCs), Union Gas and Enbridge, substantial dollars were reflected in the LDC's Quarterly Rate Adjustment Mechanism (QRAM) filings for Q2 of 2014. The QRAM is a mechanism to allow for cost recovery of actual gas supply costs through the combination of a forecast-based rate and a true-up component to account for past variances between actual costs and recovered costs at then-existing forecast-based rates.

- Union's filings indicate a total of C$134 million in costs above existing rates during the November-March period last winter, due to C$76 million in higher prices on Union's planned purchases plus $58 million in higher prices on spot purchases to meet increased demand.[2]

- Enbridge's filings indicate a total of C$643 million in costs above existing rates during the November-March period last winter, due to higher prices on planned purchases and incremental spot purchases.[3]

b. Weather

Ontario

Last winter's weather was characterized by extreme, persistent, and widespread cold. Union Gas reported that its franchise area was the coldest since its records began in 1969, with weather that was 15.5%, 16.5% and 18.4% colder than normal in November, December and January, respectively.[4] FIGURE 1 shows heating degree day (HDD)[5] data for three large cities covering the range of Ontario's more populous areas that were colder than any of the prior 10 years, as follows:

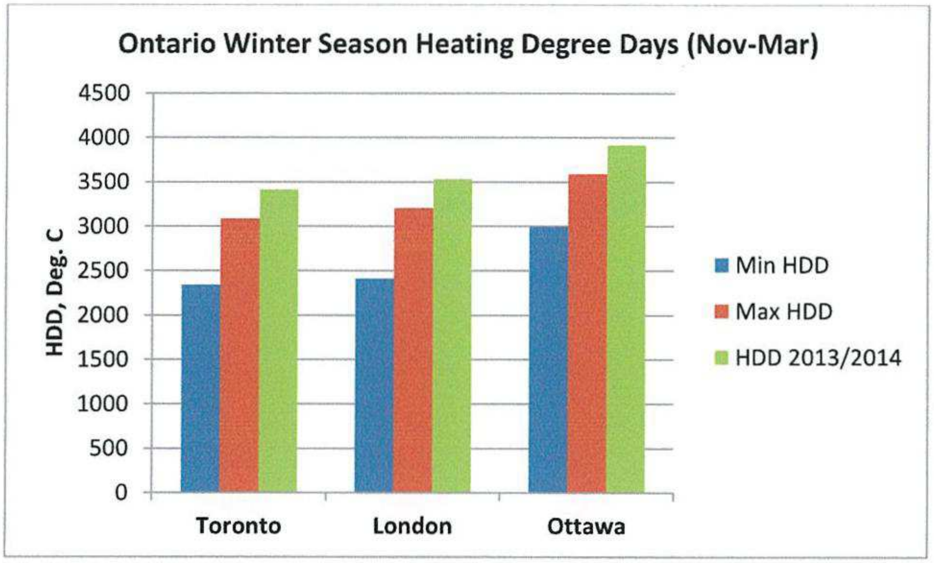
- Toronto: 11% colder than 2010/11 (coldest there in prior 10 years),
- London: 10% colder than 2010/11 (coldest there in prior 10 years), and
- Ottawa: 9% colder than 2010/11 (coldest there in prior 10 years).

[2] See Union Gas Limited, April 1, 2014 QRAM Application (EB-2014-0050), Pre-Filed Evidence of Chris Shorts, Director, Gas Supply and Mary Evers, Manager, Gas Supply, (Tab 1, p.1), April 6, 2014.

[3] See Enbridge Gas Distribution Inc., Q2 2014 QRAM Application (EB-2014-0039), Gas Acquisition Costs Component of the Purchased Gas Variance Account, Ex. Q2-3, Tab 1, Schedule 2, p. 1 of 7), col. 6, items 8-12.

[4] Union QRAM filing, Tab 1, p. 15.

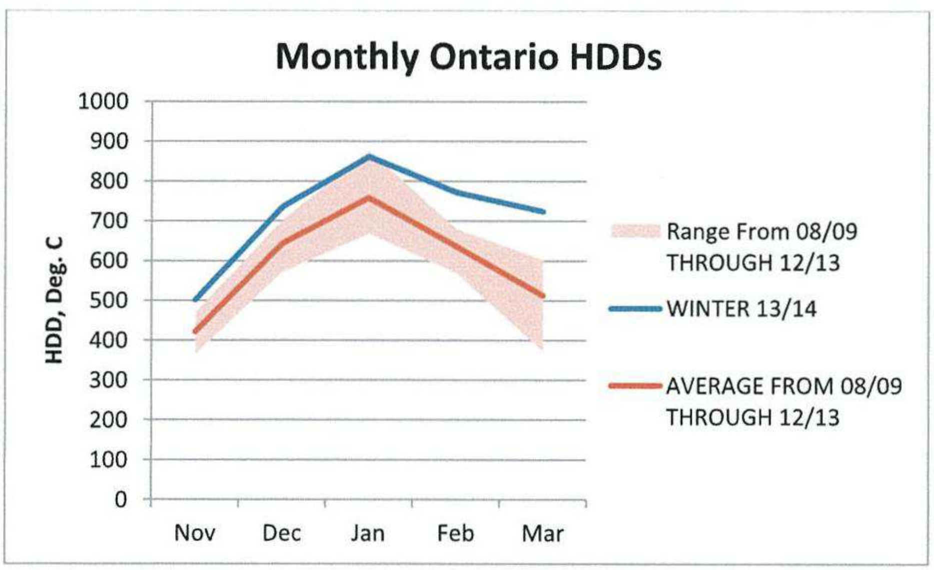
[5] Heating Degree Days is defined as the number of degrees by which a day's mean temperature was below 65 degrees Fahrenheit, or below 18.3 degrees Celsius. HDD's for a period of time is the sum of the HDD value for each day in the time period.



Source: Navigant/Aegent/Environment Canada

FIGURE 1: ONTARIO WINTER SEASON HEATING DEGREE DAYS

Confirming that last winter was persistently colder than normal in Ontario, FIGURE 2 shows that HDDs exceeded the prior 5-year maximum for virtually all of winter, with pronounced cold in February and early March. HDDs were 21.0% above average for the winter, starting the season at 19.2% above average during November and ending at 41.4% above average during March.



Source: Navigant/Aegent/Environment Canada

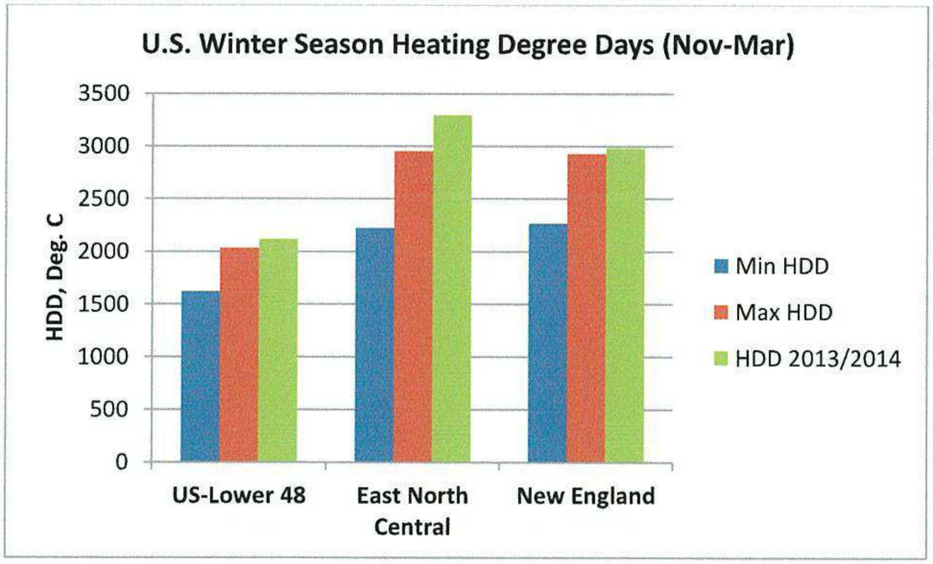
FIGURE 2: ONTARIO MONTHLY HEATING DEGREE DAYS

U.S.

In the U.S., the American Gas Association reported that last winter was the second coldest in 29 years across the U.S. as a whole, and that includes the fact that it was warmer than normal in the Pacific (composed of WA, OR and CA) and Mountain (composed of MT, ID, WY, CO, UT, NV, AZ and NM) regions that make up about one-third of the country.[6] The East North Central census region (ENC, composed of MI, OH, IN, IL, and WI) was the coldest in the 29 years reported. The East South Central (composed of KY, TN, AL and MS) and the South Atlantic (composed of WV, MD, DE, VA, NC, SC, GA and FL) regions were their second coldest, and New England (composed of ME, VT, NH, MA, CT and RI) and the Middle Atlantic (composed of NY, NJ and PA) were their third coldest in the 29 years.[7]

FIGURE 3 shows HDD data for three regions in comparison to the range for the prior 10 years, as follows:

- Lower 48: 4% colder than 2010/11 (coldest there in prior 10 years),
- East North Central: 12% colder than 2010/11 (coldest there in prior 10 years), and
- New England: 2% colder than 2004/05 (coldest there in prior 10 years).

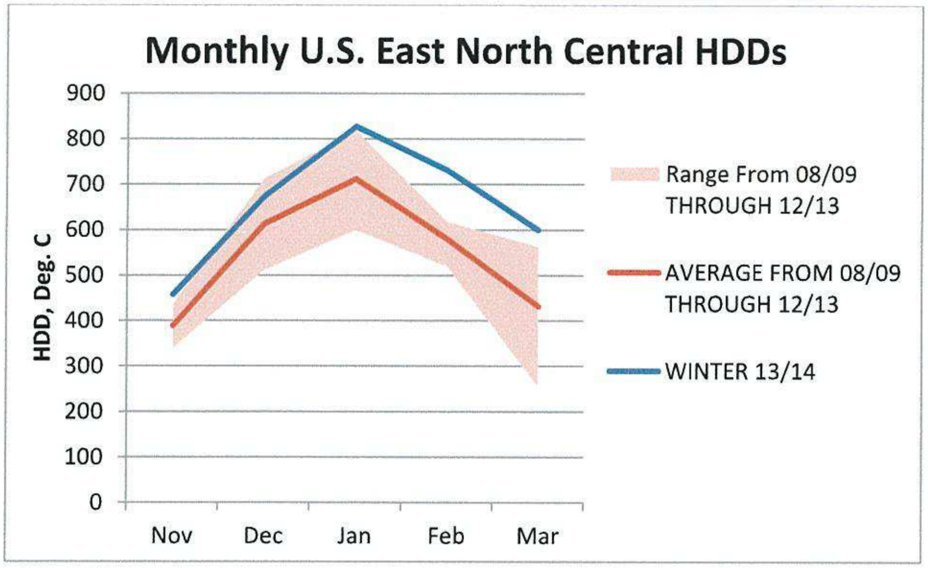


Source: Navigant/U.S. National Oceanic and Atmospheric Administration

FIGURE 3: U.S. WINTER SEASON HEATING DEGREE DAYS

As can be seen from FIGURE 4, the winter was persistently colder than normal in the U.S. In the East North Central region, where the more significant effects of the polar vortex were first felt, HDDs were 20.8% above average for the winter, starting the season at 17.8% above average during November and ending at 39.1% above average during March.

[6] "Promise Delivered: Planning, Preparation and Performance during the 2013-14 Winter Heating Season", American Gas Association, September 2014, Making the Statistical Case, p.9.
[7] Id.



Source: Navigant/U.S. National Oceanic and Atmospheric Administration

FIGURE 4: U.S. EAST NORTH CENTRAL MONTHLY HDDS

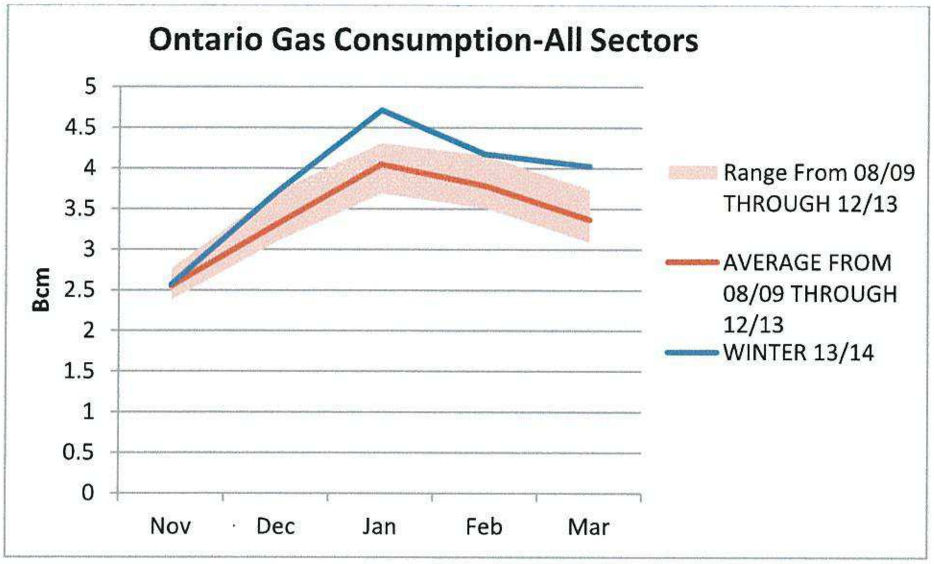
c. Demand

Ontario

In concert with the far-colder-than-normal weather data, natural gas demand was similarly noteworthy. Demand for the sum of residential, commercial and industrial customers and the electric generation sector, as well as for each sector individually, was above the 5-year average for each winter month, and particularly so as the winter progressed.

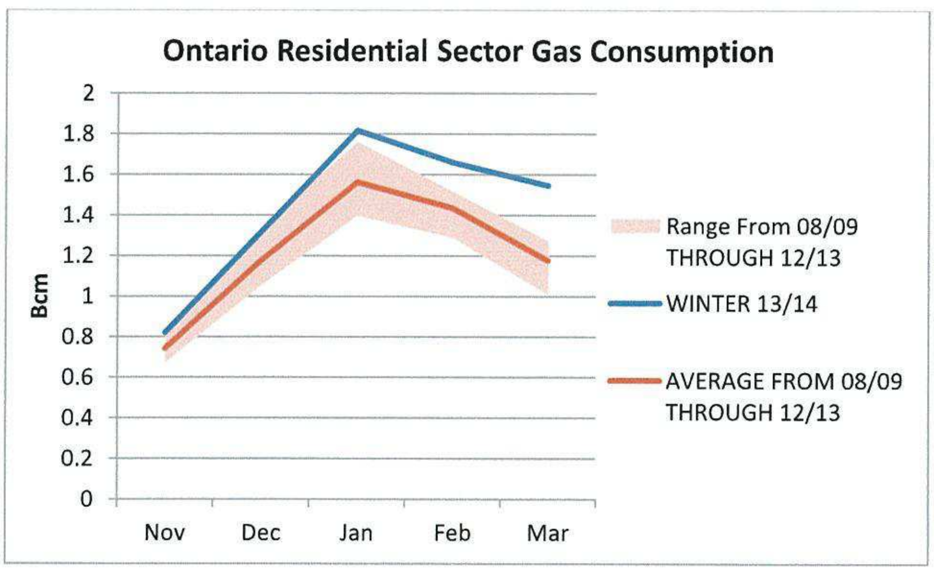
Total gas consumption was 12.5% higher than the season average for the prior five years, ranging from 0.9% greater in November to 19.3% greater in March. The residential sector was 17.6% higher than the season average, while the commercial sector was 19.4% higher and the industrial sector was 7.8% higher. The electric generation sector was 4% lower than the season average.[8] Demand trends can be seen in FIGURE 5 through FIGURE 9, and highlight the late winter season increases in residential and commercial sector consumption (versus historical averages) that correspond to the colder than average weather as shown in FIGURE 2, above.

[8] Gas consumption for electric generation was estimated from IESO data for gas-fired generation (in MWh), using an estimated heat rate of 8.0 MMBtu per MWh. At that heat rate, the 2013 gas-fired electric generation of 17.3 TWh would require 139 million MMBtu, or approximately 3.93 Bcm of natural gas. With the residential/commercial/industrial gas consumption for 2013 totaling 26.56 Bcm, the natural gas consumption for electric generation represented about 13% of total Ontario gas consumption for the year. While this share is expected to grow in the future, it is currently as low as it is because the 17.3 TWh of gas-fired generation represents only 11% of total Ontario electric generation (despite gas-fired capacity being 29% of total installed electric generation equipment in Ontario).



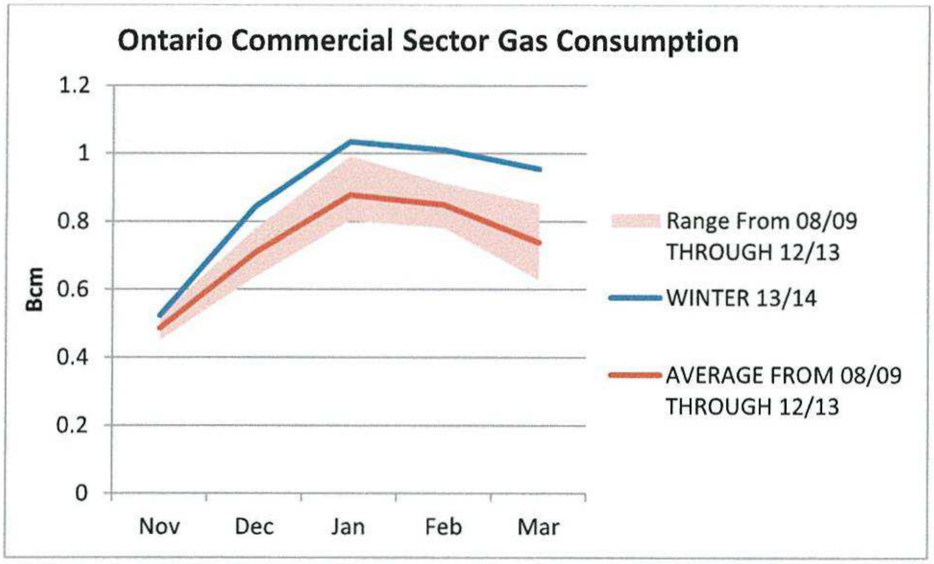
Source: Navigant/Statistics Canada

FIGURE 5: ONTARIO TOTAL GAS DEMAND



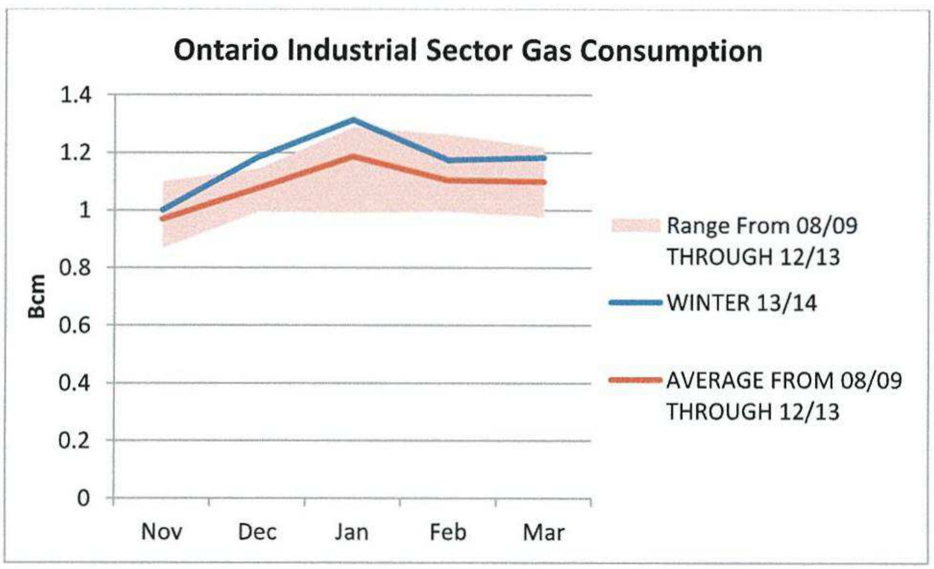
Source: Navigant/Statistics Canada

FIGURE 6: ONTARIO RESIDENTIAL GAS DEMAND



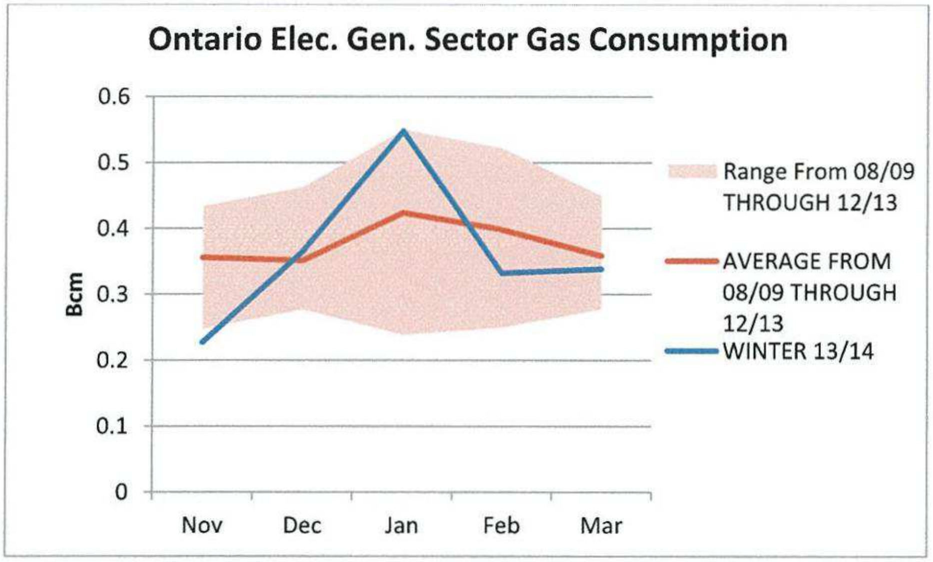
Source: Navigant/Statistics Canada

FIGURE 7: ONTARIO COMMERCIAL GAS DEMAND



Source: Navigant/Statistics Canada

FIGURE 8: ONTARIO INDUSTRIAL GAS DEMAND



Source: Navigant/Ontario Independent Electric System Operator

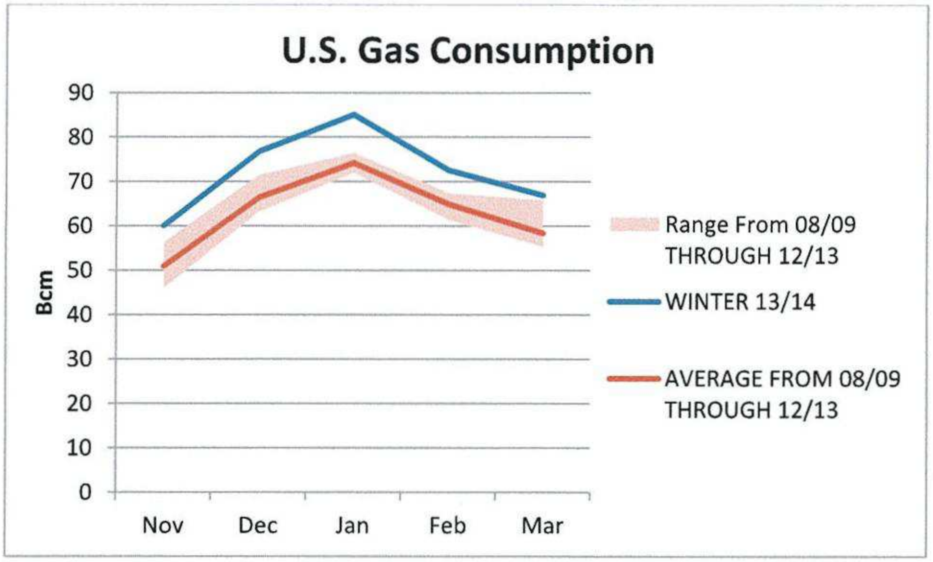
FIGURE 9: ONTARIO ELECTRIC GENERATION GAS DEMAND

Monthly total gas demands last winter exceeded the maximum monthly demands, over the prior five years from January through March, and was only 0.2% below the December maximum. The residential sector exceeded four of the five winter month maximums, and exceeded the monthly maximums for the season by an average of 6.5%. The commercial sector also exceeded four of the five winter month maximums, and exceeded the monthly maximums for the season by an average of 7.0%. Monthly industrial demands slightly exceeded prior maximums for December and January, but overall trailed the maximums for the season by about 2.7%. While industrial demand was still above average in February and March, unlike the residential and commercial sectors it did exhibit a decrease versus its trend above prior maximums, indicating some possible responsiveness to the increasing level of prices, as opposed to the more temperature-sensitive residential and commercial sectors. In addition, interruptible customers, who may lose service in extreme conditions, are generally drawn from the industrial sector.

A specific additional factor that influenced the market through its impacts on demand was the requirement of Union Gas direct purchase customers to meet a "checkpoint" balancing requirement at the end of February. This tariff-based requirement had the effect of increasing the demand in the spot market by a significant amount in a short period of time. The checkpoint balancing requirement will be discussed more in Section 2.e.

U.S.

Monthly demands were higher than the averages of the prior 5 years every month in the US, with the total gas consumption for the winter season being 14.8% higher than average. As can be seen in FIGURE 10, monthly demands each month last winter even exceeded the maximum monthly demands over the prior five years in every month, by an average of 6.9% above the prior monthly maximums.

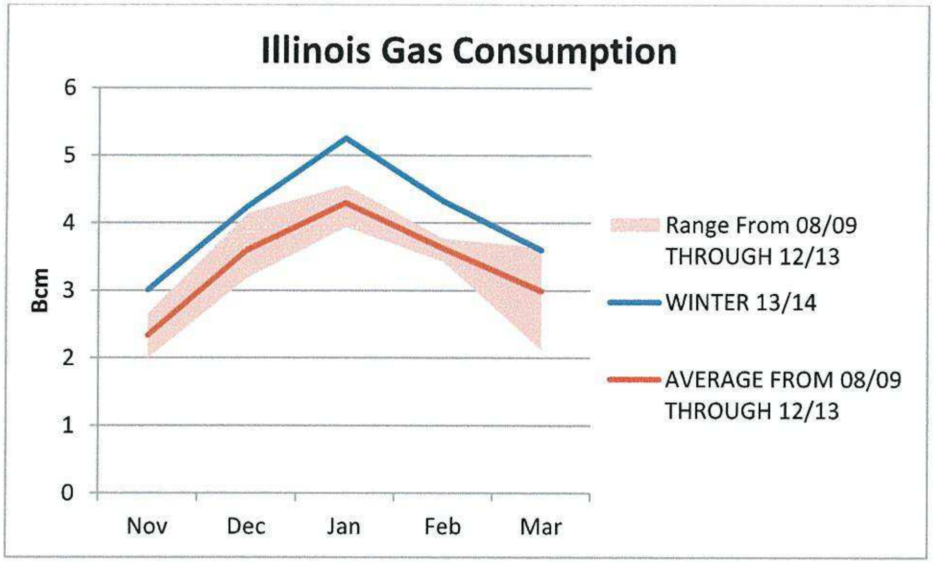


Source: Navigant/U.S. Energy Information Administration

FIGURE 10: U.S. GAS DEMAND

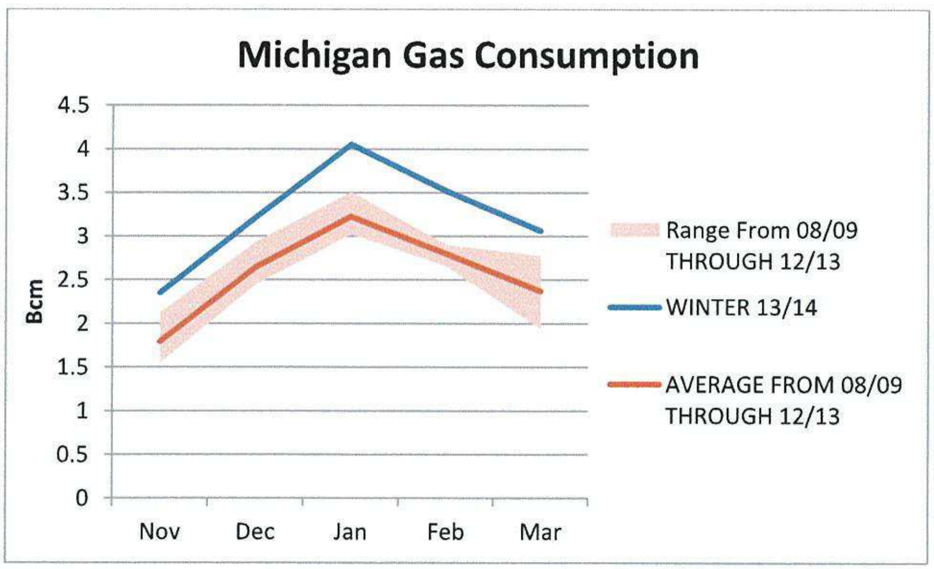
To complete the picture of U.S. demand with a focus on markets close to Ontario, we look briefly at Illinois (home to the Chicago market hub) and Michigan (directly tied in to Ontario infrastructure at Sarnia and Windsor). Illinois and Michigan had particularly strong demands, as shown in FIGURE 11 and FIGURE 12. Illinois monthly demands exceeded the averages of the prior 5 years every month, with the seasonal total gas consumptions being 21.3% above average and the highest percent increase being 29% above average in November. Michigan monthly demands exceeded the averages of the 5 prior years every month, with the seasonal total gas consumptions being 26.2% above average and the highest percent increase being 31.1% above average in November.

Illinois monthly demands exceeded the maximum monthly demands in four out of five months over the prior five years, by an average of 8.9% above the prior monthly maximums. For Michigan, the monthly demands exceeded the prior 5-year monthly maximums every month of the season, by an average of 13.3%.



Source: Navigant/U.S. Energy Information Administration

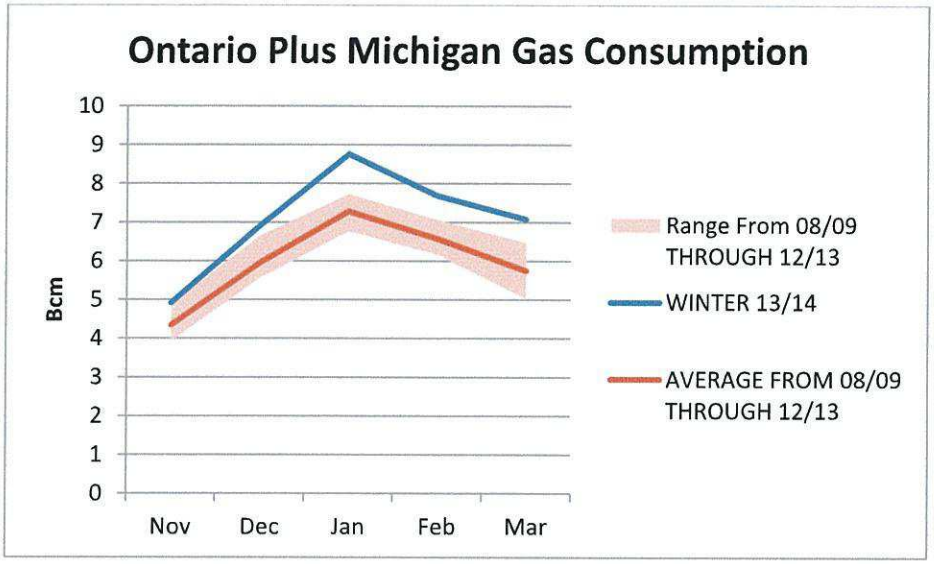
FIGURE 11: ILLINOIS GAS DEMAND



Source: Navigant/U.S. Energy Information Administration

FIGURE 12: MICHIGAN GAS DEMAND

Looking at combined Michigan and Ontario demand raises the Ontario seasonal demand percentages from 12.5% above average to 18.4% above average (for the combined demands), and maximum monthly demands from 2.0% above prior 5-year maximums to 7.2% above prior 5-year maximums, as can be seen in FIGURE 13. Looking at the combined loads for the interconnected Michigan and Ontario markets shows how the high early season demand in Michigan could have strengthened perceived demand in Ontario at that time

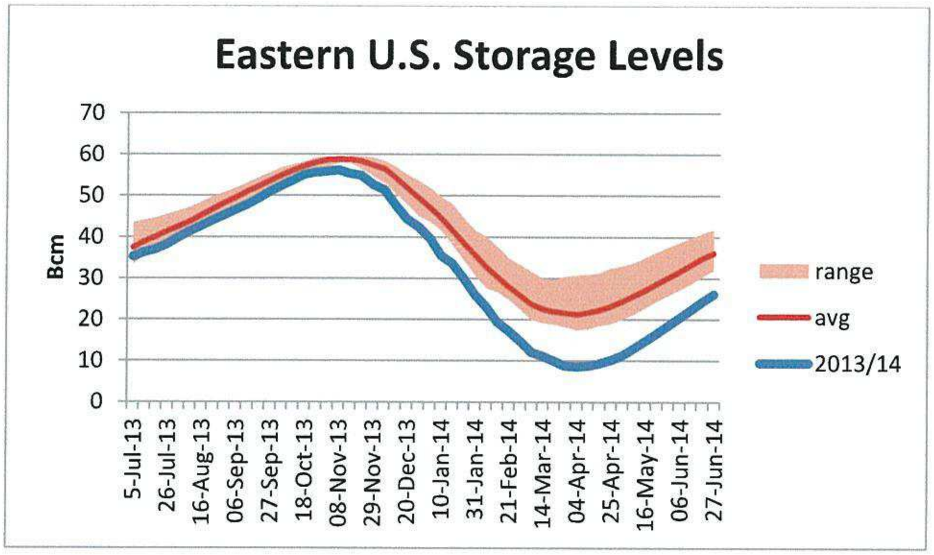


Source: Navigant/U.S. Energy Information Administration/Statistics Canada

FIGURE 13: ONTARIO PLUS MICHIGAN GAS DEMAND

d. Supply

As early winter season impacts were felt in the U.S. before Canada, we will briefly summarize the Eastern U.S. storage conditions. As shown in FIGURE 14, storage levels were already below the bottom of the prior 5-year range in October after an injection season (i.e. additions into storage) that appears to have been a bit behind average and to have started to flag a bit early. At the start of November, inventories were at 95% of average levels for the time, perhaps as a reaction to several recent warmer winters. By the end of December, much-higher-than normal gas demands had already dropped Eastern U.S. storage levels to 14% below normal levels for the time, at 73% of the average November 1 inventory level (i.e. 42.5 Bcm) versus 84% of the average level (i.e. 49.5 Bcm). The continuing and increasingly cold weather kept up the much-higher-than-normal gas demands into January and then through the rest of the winter, leading to Eastern U.S. storage levels at the end of January being 28% below average levels for the time, at 44% versus 61% of the average November 1 inventory level. These figures are summarized in TABLE 1.



Source: Navigant/U.S. Energy Information Administration

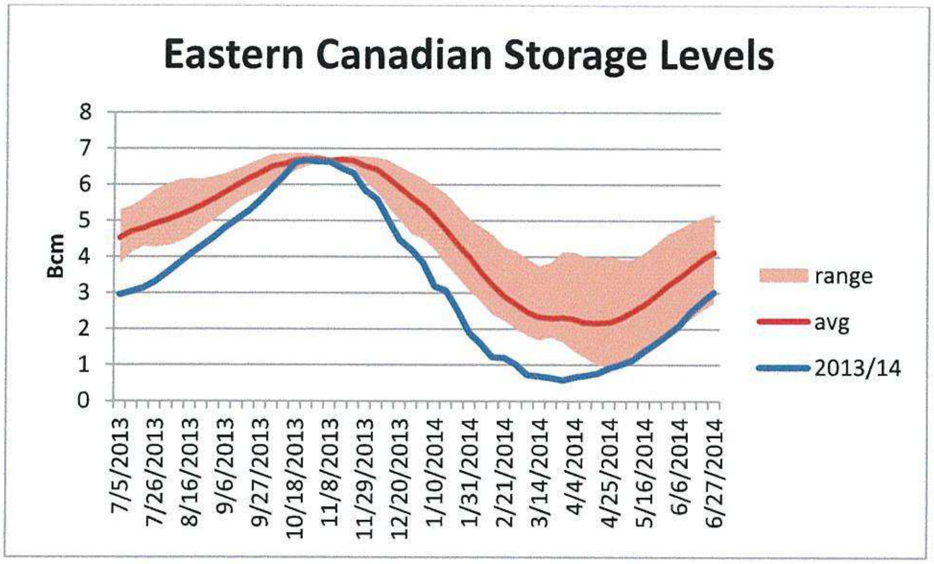
FIGURE 14: EASTERN U.S. GAS STORAGE LEVELS

TABLE 1: SUMMARY OF MONTHLY U.S. GAS STORAGE ACTIVITY AND METRICS

Date	Average Storage Level (Bcm)	2013/14 Storage Level (Bcm)	Average Withdrawal for Month (Bcm)	2013/14 Withdrawal for Month (Bcm)	2013/14 withdrawals as percent of normal withdrawals	Avg. Year Percent of Avg. Nov. 1	2013/14 Percent of Avg. Nov 1
11/1/2013	58.6	55.9				100%	95%
11/29/2013	57.4	52.7	1.2	3.2	265%	98%	90%
12/27/2013	49.5	42.5	8.0	10.2	128%	84%	73%
1/31/2014	35.6	26.1	13.9	16.5	118%	61%	44%
2/28/2014	25.8	14.9	9.7	11.2	115%	44%	25%
3/28/2014	21.5	8.8	4.3	6.1	141%	37%	15%

Source: Navigant/U.S. Energy Information Administration

Eastern Canadian storage inventories quickly dropped even farther below average during the winter, as shown in FIGURE 15. By the end of December, much-higher-than normal gas demands had already dropped Eastern Canadian storage levels to 26% below average levels for the time, at 63% of the average November 1 inventory level (i.e. 4.2 Bcm) versus 84% of the average level (i.e. 5.6 Bcm), as presented in TABLE 2.



Source: Navigant/Enerdata

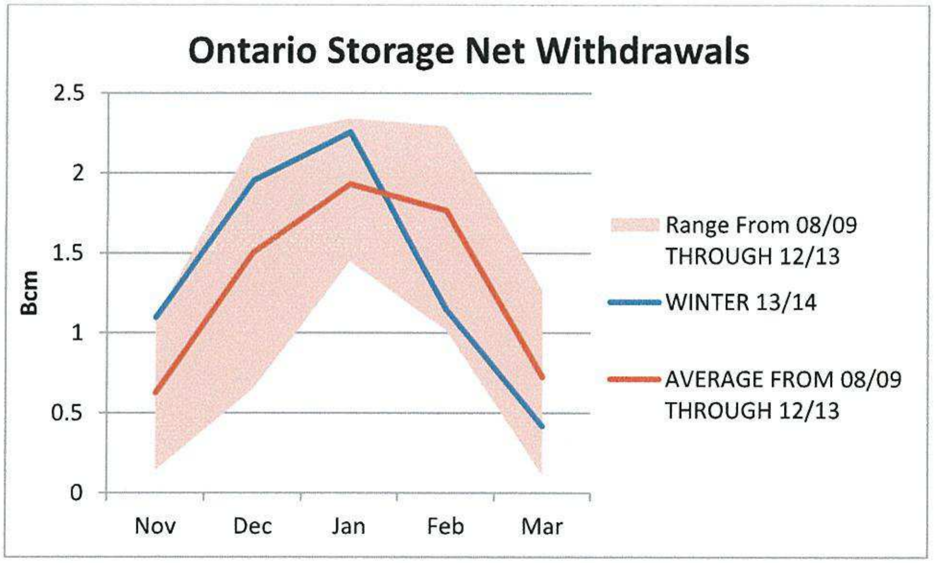
FIGURE 15: EASTERN CANADIAN GAS STORAGE LEVELS

TABLE 2: SUMMARY OF EASTERN CANADIAN MONTHLY GAS STORAGE ACTIVITY AND METRICS

Date	Average Storage Level (Bcm)	2013/14 Storage Level (Bcm)	Average Withdrawal for Month (Bcm)	2013/14 Withdrawal for Month (Bcm)	2013/14 withdrawals as percent of normal withdrawals	Avg. Year Percent of Avg. Nov. 1	2013/14 Percent of Avg. Nov 1
11/1/2013	6.7	6.6				100%	99%
11/29/2013	6.5	5.8	0.2	0.8	427%	97%	87%
12/27/2013	5.6	4.2	0.9	1.6	188%	84%	63%
1/31/2014	4.0	1.9	1.7	2.3	139%	59%	28%
2/28/2014	2.7	1.0	1.3	0.9	68%	40%	15%
3/28/2014	2.3	0.6	0.4	0.4	115%	34%	9%

Source: Navigant/Enerdata

Net storage withdrawals in Eastern Canada in November through January were well above normal, exceeding the average withdrawals, for those months (totaling 2.7 Bcm) by 2.0 Bcm, or 74%. After three months of heavy decreases in storage inventories, levels were less than half of average for the time (at 28% versus 59% of average inventories at the start of November), and were not sufficient for storage to effectively meet continued high demands in February. Due to the low storage inventories, February net withdrawals were less than 70% of normal for the month (as shown in FIGURE 16), despite the fact that Ontario gas demand in February was 13.5% above normal.

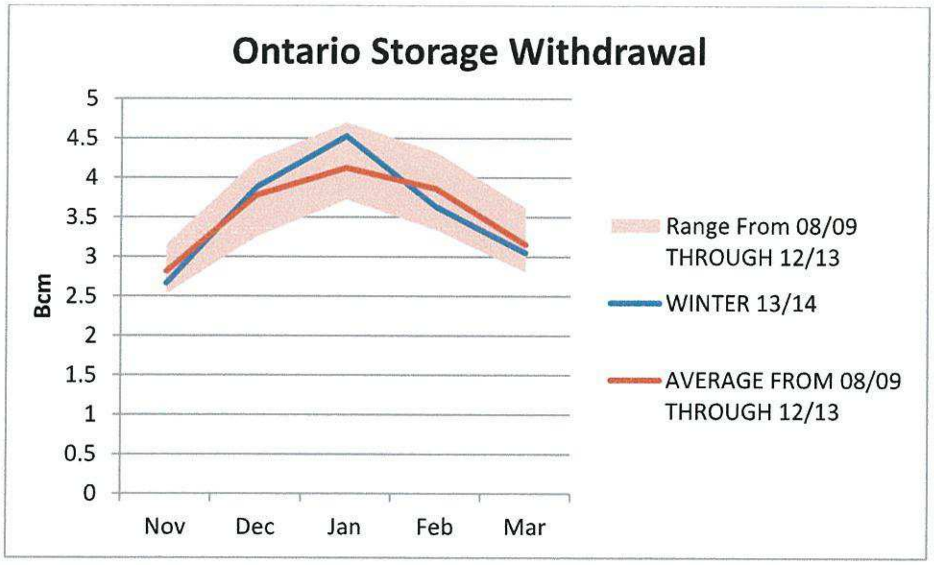


Source: Navigant/Statistics Canada

FIGURE 16: ONTARIO STORAGE WITHDRAWALS (NET)

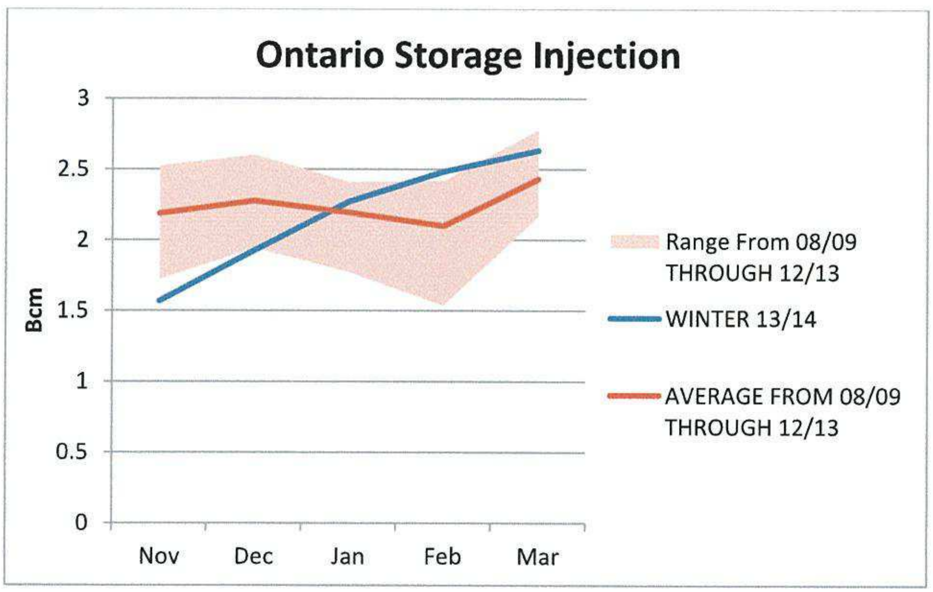
Looking at withdrawals from storage and injections into storage separately, data shows that the November and December withdrawals were about average (shown in FIGURE 17), but that injections were below average (shown in FIGURE 18), resulting in large net withdrawals. These successive large net withdrawals, combined with a large withdrawal in January, led to the steep and continued drop in overall storage inventories as the cold winter conditions persisted.[9]

[9] Note that the storage inventories shown in FIGURE 15 and TABLE 2 reflect total physical inventory levels, which should be heavily driven by LDC actions, but not entirely driven to the extent that LDC contractual rights to storage are less than overall storage rights.



Source: Navigant/Statistics Canada

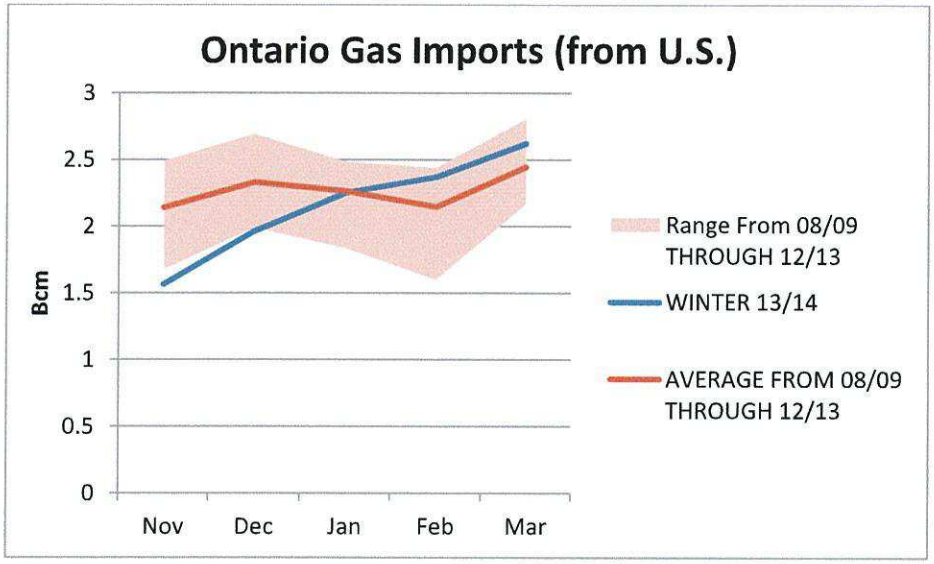
FIGURE 17: ONTARIO STORAGE WITHDRAWALS



Source: Navigant/Statistics Canada

FIGURE 18: ONTARIO STORAGE INJECTIONS

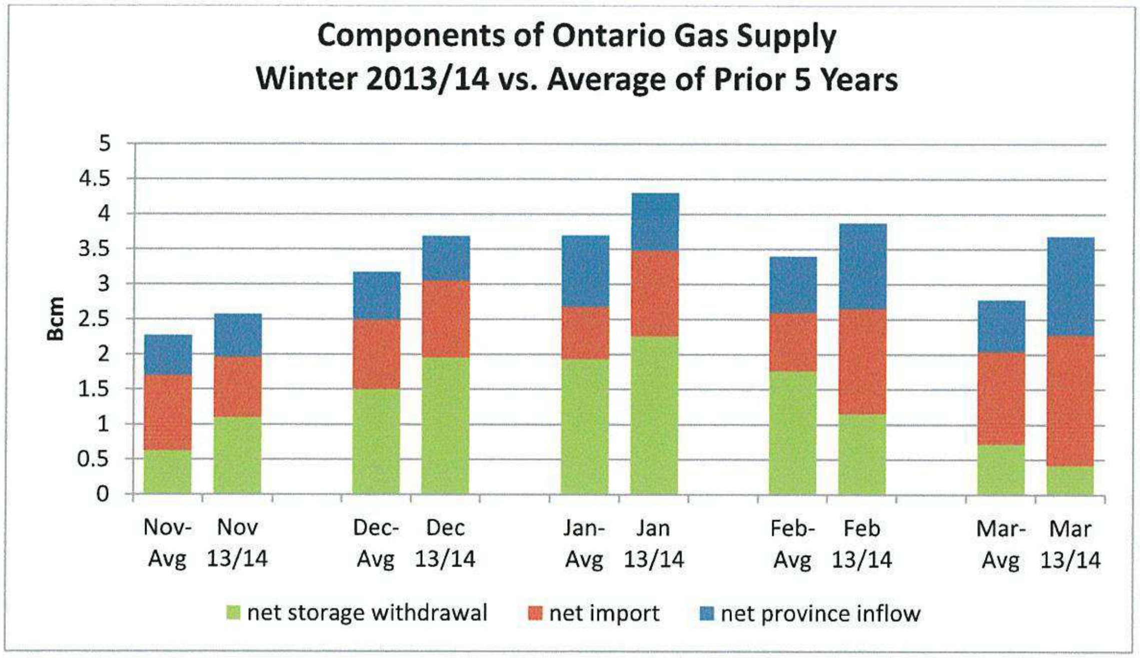
Consistent with net Eastern Canadian storage withdrawals being large early in the winter (as the main source of supply to meet demands) is FIGURE 19 showing imports of gas into Ontario from the U.S. being well below normal in November and December, and only returning to average levels in January.



Source: Navigant/Statistics Canada

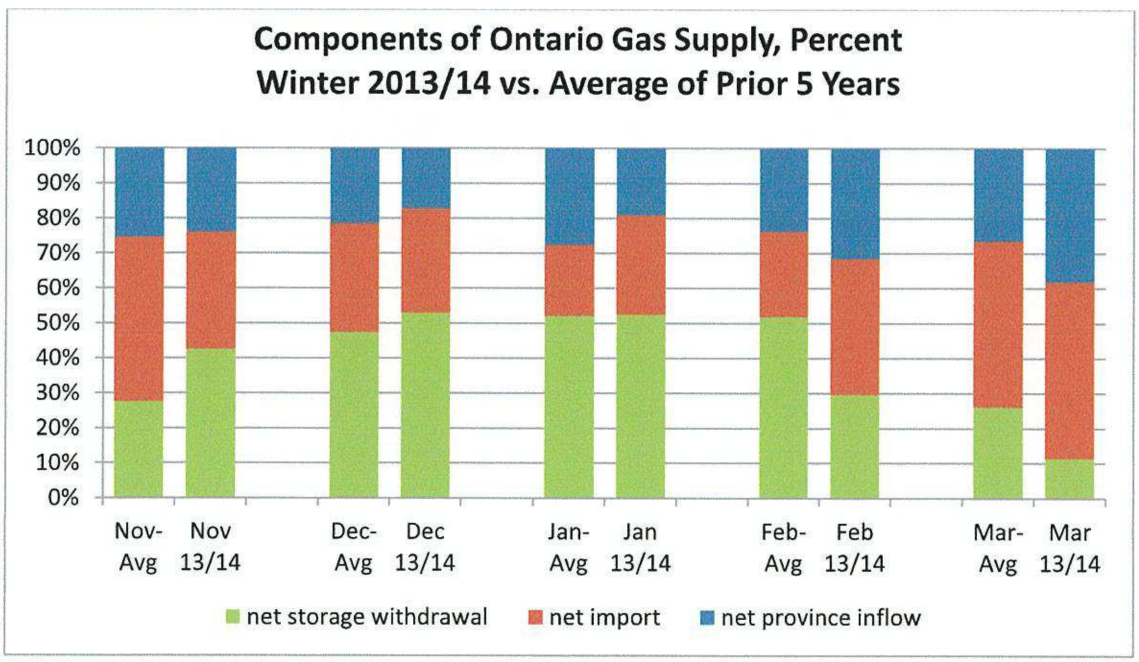
FIGURE 19: ONTARIO IMPORTS (FROM U.S.)

In order to meet a large demand in February, without sufficient gas in local storage, LDCs had to meet their gas demand requirements through additional procurement. As indicated to us by Enbridge, with storage down and their long-haul transportation (from the U.S. or Canada) already filled, they had to buy at Dawn. The data indicates that gas imports into Ontario from the U.S. continued to increase beyond average levels at this time, as can be seen in FIGURE 19, above. FIGURE 20 summarizes the components of gas supply for Ontario last winter versus the average of the prior five years. As can be seen, the total volume of purchases, composed of net imports from the U.S. plus the inflow from Alberta net of outflow to Quebec, but not including storage withdrawals, in February was significantly greater than average, at about 2.7Bcmversus 1.6Bcm. FIGURE 21 shows the components of gas supply for Ontario on a percentage basis.



Source: Navigant/Statistics Canada

FIGURE 20: COMPONENTS OF ONTARIO GAS SUPPLY

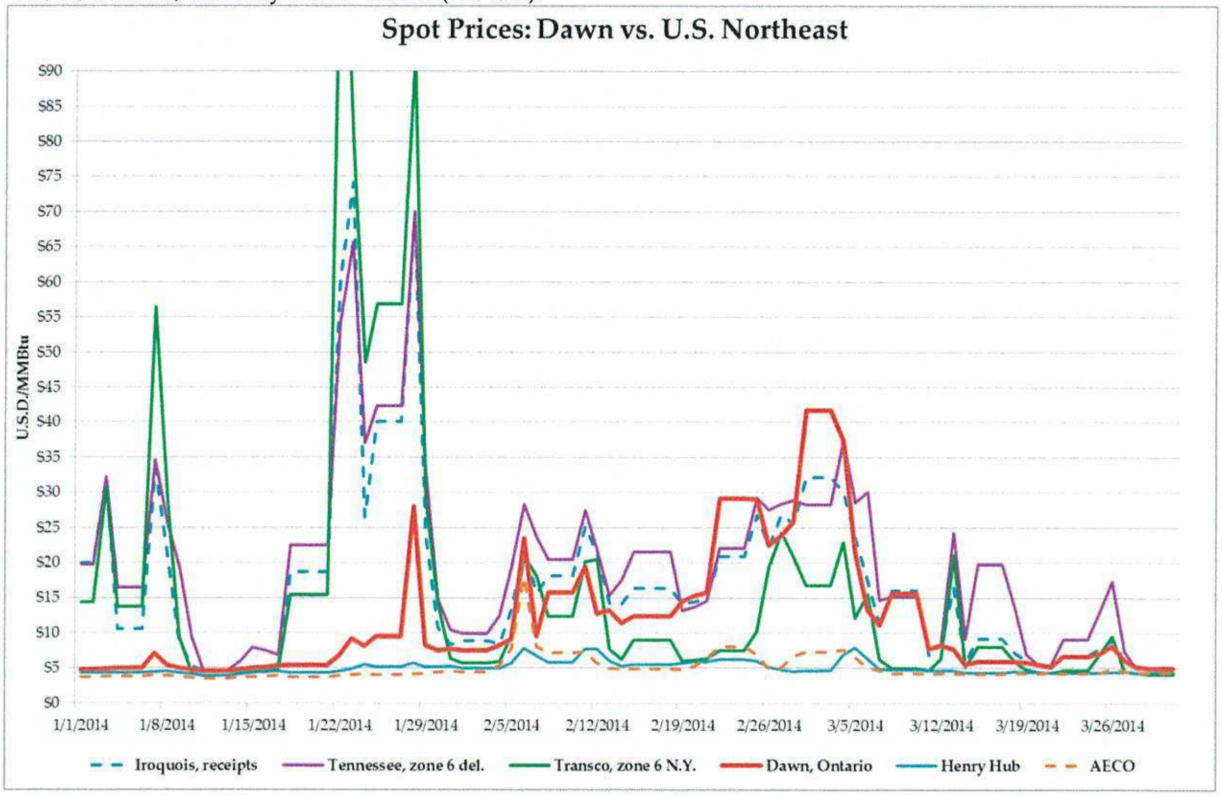


Source: Navigant/Statistics Canada

FIGURE 21: COMPONENTS OF ONTARIO GAS SUPPLY-PERCENT

e. Price Behavior

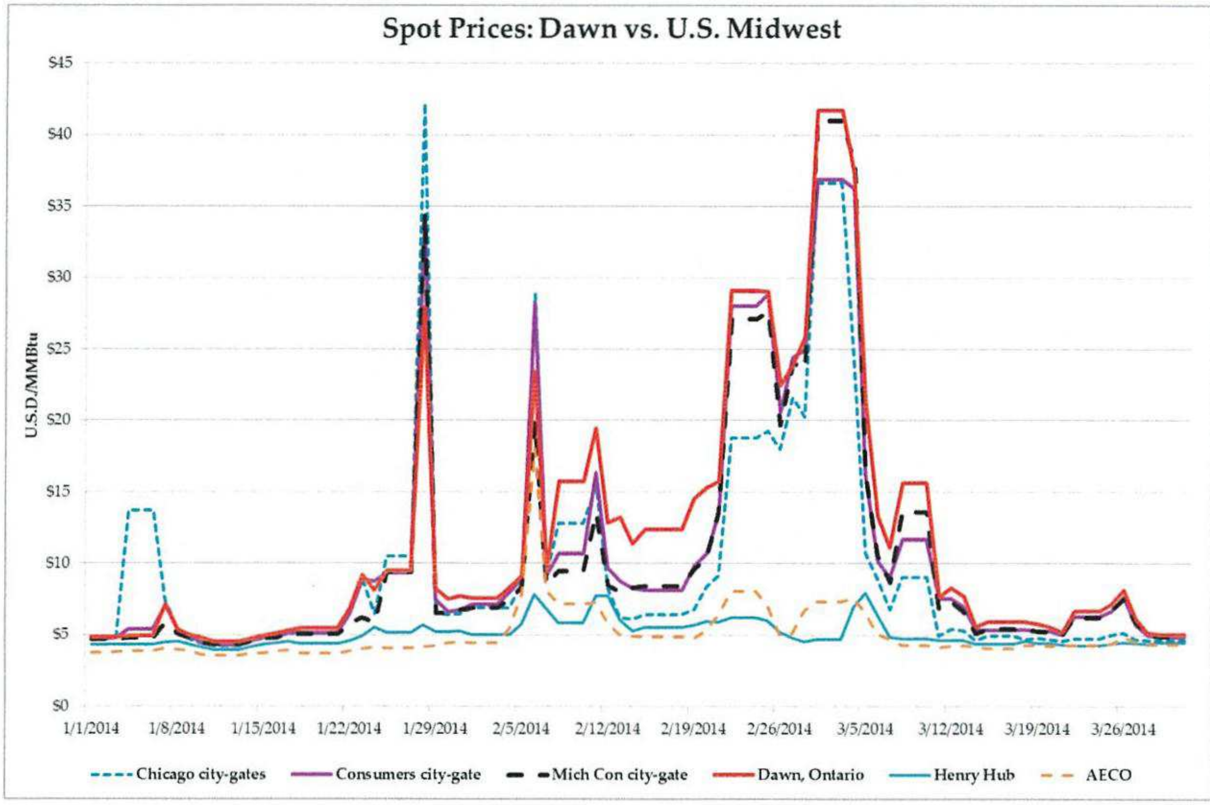
Spot prices were elevated across most market points of North America for at least some period of the winter. The Northeast, as usual, experienced the largest price spikes in the U.S.. As indicated in FIGURE 22, prices in New York reached over US$120/MMBtu in late January, while the Dawn price spike at about that time (the first of the winter, on January 28) was to just under US$30/MMBtu. Regarding volatile market behavior indicative of peak day type events, it is a relatively normal occurrence in the Northeast (although usually with prices not going much above US$40/MMBtu), and much less normal at Dawn. In the prior 16 years going back through 1998, there were eight events where Northeast gas prices reached US$20/MMBtu, but only one at Dawn (in 2003).



Source: Navigant/Platts

FIGURE 22: SPOT PRICES: DAWN VS. U.S. NORTHEAST

The particular January 28 price spike at Dawn can be put into context by looking at the relationships between Dawn prices and prices in the U.S. Midwest. FIGURE 23 shows the same Dawn price series, but compared to citygate prices at Chicago and in Michigan. What can be seen is that on the same day there were also price spikes at the U.S. Midwest citygates, but reaching higher, to above US$30 and US$40 per MMBtu, which was counter to the historical relationship to Dawn. There was a similar, but more modest, Chicago price spike event in early January, from the 4th to 6th. These events may relate to anecdotal information from Union Gas that competition for Dawn gas from the Chicago market could have had a role in driving early season Ontario demand to be met in large part from storage rather than from purchases. The fact that the spikes were larger in the U.S. Midwest than at Dawn would seem to indicate that the dynamic originated in the U.S., with some attenuated affect in Ontario.



Source: Navigant/Platts

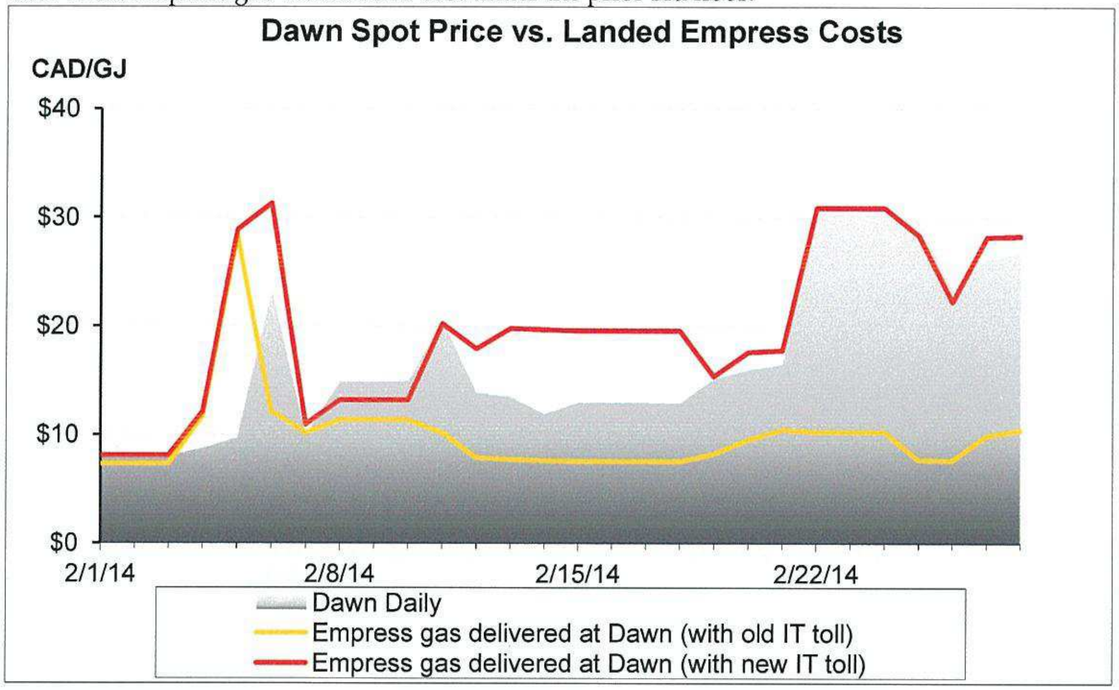
FIGURE 23: SPOT PRICES: DAWN VS. U.S. MIDWEST

Perhaps the most interesting developments with regard to Dawn prices occurred in February, which saw a relatively steady increase in price level over the course of the month from under US$8/MMBtu to over US$40/MMBtu on March 1. Factors that contributed to these price levels include those already outlined, such as the persistence of widespread cold weather creating record gas demands, and large cumulative storage withdrawals during November through January leading to lower gas inventories in storage and thus to greater spot purchases in February, as well as several additional items.

The first additional factor relates to the rates set by TransCanada PipeLine (TCPL) to move gas from Empress to Dawn on TCPL. Winter 2013/14 was the first in which TCPL had the ability to set interruptible (IT) and short-term firm transportation (STFT) tolls at their discretion, pursuant to the NEB's decision in TransCanada's application to restructure its Mainline ratemaking.[10] The NEB decision included changes to the IT/STFT rate structure as a way for TCPL to improve cost recovery on its Mainline by incentivizing the purchase of long term firm transportation (FT) versus IT/STFT. By

[10] RH-003-2011, Application for Business and Services Restructuring Proposal and 2012 & 2013 Mainline Final Tolls.

increasing the minimum IT/STFT bid toll, TCPL effectively increased the cost of incremental gas from Alberta in Ontario. As shown in FIGURE 24, with respect to February, the landed price of Empress gas at Dawn, based on the new higher IT tolls with a bid floor that averaged C$11.97/GJ, was at or above the actual Dawn prices on all but five days in the month. On the other hand, assuming the prior level of IT toll bid floor of C$2.08/GJ, the landed price of Empress gas at Dawn would have been below the actual Dawn prices on all but three days in the month. The higher IT tolls meant that spot Empress gas was uneconomic in the Dawn market, with other supplies on the margin, as prices were ultimately higher than what Empress gas would have cost under the prior bid floor.

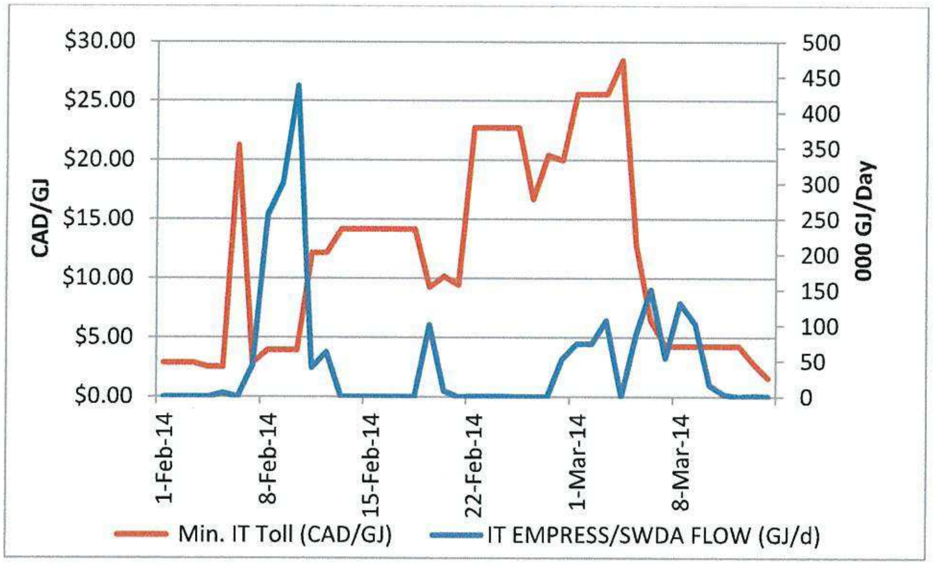


Source: Aegent/CGPR/TCPL

FIGURE 24: SPOT PRICES: DAWN VS. LANDED EMPRESS @ TCPL IT MIN BID

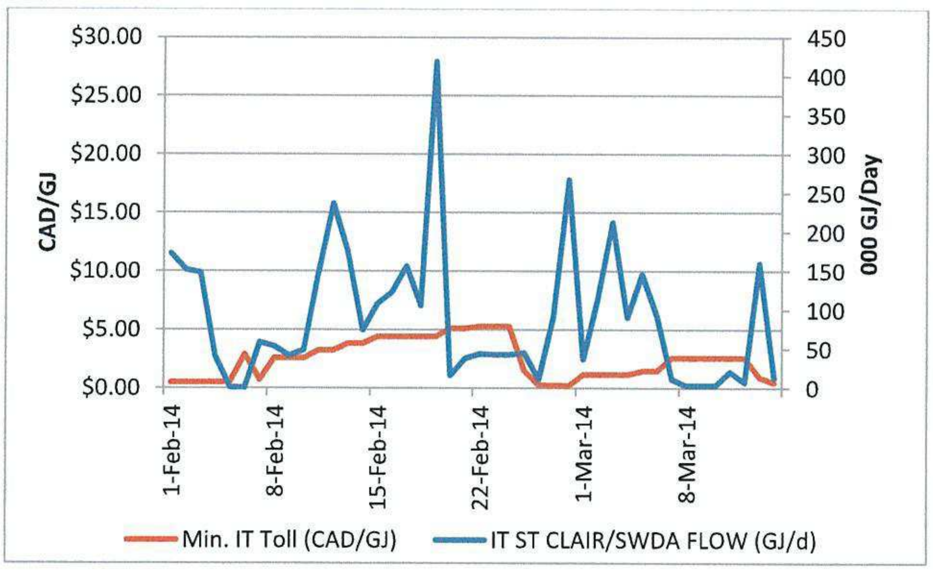
FIGURE 25 illustrates the impact of the IT tolls by highlighting that IT flows from Empress to Dawn occurred on a limited number of days during the period from February 1 through March 15, with 21 days having flows of zero or less than 1,000 GJ. The minimum bid set for the IT toll from Empress averaged C$11.65/GJ during this period, and only 2.1 PJ flowed. For comparison,

FIGURE 26 shows that IT flows from St. Clair to Dawn over the same period were 3.8 PJ, with flows over 1,000 GJ occurring on all but two days. The average IT bid toll on the St. Clair to Dawn path was only C$2.44/GJ. The resulting economic limitations (due to transport costs) on sourcing incremental gas supply from Empress meant that more expensive gas would need to be obtained, effectively raising prices at Dawn.



Source: Aegent/TCPL

FIGURE 25: FLOWS (IT) FROM EMPRESS VS. MIN. IT TOLL



Source: Aegent/TCPL

FIGURE 26: FLOWS (IT) FROM ST. CLAIR VS. MIN. IT TOLL

The second additional factor impacting prices relates to the "checkpoint" balancing requirement on Union Gas' direct purchase customers. Under Schedule 2 to Union's Southern Bundled T service, a Banked Gas Account is required, reflecting the cumulative balance between a customer's receipt of

Union-distributed gas and the customer's deliveries of gas to Union. A positive balance means the customer has delivered more gas to Union than has been distributed to the customer by Union. A customer's contract will contain a Winter Checkpoint Quantity (and an analogous Fall Checkpoint Quantity) that represents the minimum balance that must be in its Banked Gas Account as of the Winter Checkpoint Date (February 28). The amount of additional gas that a customer may need to deliver to Union by February 28 will vary according to its existing Bank Gas Account balance.

While Schedule 2 to Union's Bundled T service says that a customer is "expected to take balancing actions early in the winter to ensure that the BGA balance is not less than the Winter Checkpoint Quantity as of the Winter Checkpoint Date", we understand from Union that many customers will have built up significant shortfalls in their Banked Gas Accounts relative to their checkpoint quantities. The result of these customers delaying their balancing obligations all the way until the February 28 checkpoint date was to have large volumes of demand entering the market in a concentrated time period. Such demand bubbles can be expected to contribute to price volatility and, in an extremely tight market, we would expect the effect would be even more pronounced. Last winter, the market was indeed already tight, and the checkpoint balancing demand likely raised prices even higher at the end of February.

f. Conclusions—What Happened and Why

As outlined in the previous sections, there were many events unfolding in real time last winter. The most important event was the cold weather, which was widespread, persistent, and extreme. Hindsight allows all the information to be seen at once. In reality, the future is never known, although it is constantly forecasted and evaluated. It is presumed that an LDC's supply planning parameters (such as the LDC's assumed design day demand or its storage deliverability target) have been set to allow the LDC to reliably and efficiently meet expected demand. As noted by the Board, gas supply plans are "based on the amount of gas that would be expected to be needed to address the normal range of demand."[11] As unexpected events occur, such as last winter's cold, then the system is challenged. While planning necessarily involves trade-offs between the cost of mitigating risks and the potential cost impacts of the risks themselves, the nature of risk makes it highly unlikely that all risk can be mitigated at reasonable costs.

It should be remembered that while there were significant price impacts, both LDCs followed their supply plans, and neither curtailed any firm service. Following are the main conclusions about last winter's gas prices:

- Extreme winter conditions elevated natural gas demand throughout the U.S. and Ontario to record levels, leading to a tight gas market and setting the stage for additional factors that exacerbated the winter's price behavior.
- Strong Midwest demand impacted gas prices at Dawn and incented increased storage withdrawals to meet Ontario demand.
- Large storage withdrawals early necessitated large spot purchases later (which happened to be at high prices) as continued cold conditions led to persistent high demand.

[11] See Decision and Order of May 22, 2014 in EB-2014-0039, Enbridge's Q2 2014 QRAM application, p. 6.

- "Checkpoint" balancing by Union direct purchase customers, although an annual occurrence, coincided last winter with the on-going need to meet persistent high demand, exacerbating prices.
- Increased interruptible transport tolls appear to have limited the competitiveness of Empress as an economic source of supply, leading incremental gas for Ontario to be drawn from the Midwest and Northeast, further exacerbating Dawn prices
- The necessary conditions for last winter's price scenario appear to be the coincidence in both the U.S. and Canada of early, widespread and persistent high demand (resulting from the macro weather conditions).
- It is not clear whether the same weather conditions would have led to the same price impacts had supply plan requirements called for more base storage or increased firm transportation, but more storage and increased firm transportation may have helped.
- Similarly, supply plan requirements leading to more conservative use of storage withdrawals (and thus more supply procurement early in the winter) would likely have helped.

3. QRAM Discussion

a. Overview

The Quarterly Rate Adjustment Mechanism (QRAM) is a cost recovery mechanism to allow gas distributors to recover their actual gas costs since those costs can (and will) differ from whatever was assumed in order to set the distributor's rates. The purpose of the QRAM is to allow for the collection of actual costs by gas distributors in a way that provides a balance between price stability and market price sensitivity. The QRAM operates based on a 12-month price forecast that is updated quarterly, plus a true-up account (Purchase Gas Variance Account) to track the variances between actual costs and recovered costs at the existing forecast-based rates. The forecast price is computed each quarter based on a "21-day strip" that "represents the simple average of future market prices, as reported by various media and other services, over a 21-day period for a basket of pricing periods, pricing points, and pricing indices that reflects [a company's] gas purchase arrangements, both actual and anticipated, during the 12 months subsequent to the 21-day period."[12] The true-up rate rider is computed each quarter to provide for recovery of Purchase Gas Variance Account balances, plus any historical variance in collections of the PGVA rider. Cost recovery is achieved by collection of the forecast component (i.e. base rates) and the true-up component (i.e. Purchase Gas Variance Account rider), assessed against a customer's monthly gas volume.

b. Drivers

As the QRAM is a mechanism to allow for cost recovery of actual gas supply costs (through the forecast-based rates and the true-up based rate riders), the factors influencing the QRAM are essentially the factors that influence an LDC's actual gas costs. Conceptually, the various factors could be grouped into two broad categories: 1) those that are more independent, and may not generally be within an LDC's (or its regulator's) specific realm of control (although they may manage their responses to these factors), and 2) those that could potentially be more directly impacted by the operational, managerial and regulatory policies, procedures, directives and decisions of the LDC or its regulator.

[12] See Appendix A to Enbridge Q2 2014 QRAM Application (EB-2014-0039), Ex. Q2-1, Tab 2, Schedule 1, Appendix A, pp. 1-2.

- The more independent factors would include the following types of events that can impact the gas market and thus an entity like an LDC:

    1. weather
    2. outages
    3. gas supply development
    4. interstate pipeline development
    5. gas demand growth
    6. economic or business cycles
    7. world events

- Other factors that could potentially be more directly influenced by an LDC or its regulator are well-represented by an LDC's supply planning parameters, as outlined below.

c. Supply Planning Parameters

As the potentially controllable drivers of an LDC's costs and its QRAM, its supply planning parameters should be of interest from policy and commercial perspectives.

i. weather assumptions

Weather assumptions (i.e. how far away from normal weather could a season reasonably be, and what is "normal") are important because they help drive the range of potential weather outcomes that would need to be planned for.

- Union: proposed switch (for 2013) to 20-year declining trend from 55/45 blend of 30-year average and 20-year declining trend; Union reports this is the same as current Enbridge method

ii. design day criteria

Design day criteria help determine what the peak day demand assumption will be. A colder design day will require additional supply planning measures, which could range from additional storage or transportation (high fixed costs) to additional peaking resources (high variable costs).

- Union North: coldest observed day in each of six delivery areas
- Union South: 44 HDD DegC
- Enbridge: 1-in-5 forecast with log-normal (settled after an earlier request to increase from 1-in-5 to 1-in-10 with log-normal), which comes to 41 HDD DegC.

iii. demand forecast

Assumptions such as no migration between utility gas sales service and direct purchase (DP) service customers could lead to the need for increased incremental supply with possible market impacts. The demand forecasting itself is likely less controversial.

- Union: no migration during year between DP and sales service customers
- Union: actual winter 13/14 migration was 25,000 DP customers returning to sales service, leading to 1.8 PJ of incremental supply needed, (Union Gas Q2 2014 QRAM, Tab 1, p.8).

iv. firm transportation planning criteria

The decision to purchase annual firm transportation is important because it creates a fixed cost obligation that could prove stranded, but could also result in a much mitigated result in the case of high demand.

- Union South: firm transport capacity set at average daily quantity, used at 100% load factor
- Union North: firm transport capacity set at design day, which leaves 10.4 PJ of unused capacity on lower demand days, i.e. Unabsorbed Demand Charges (2013 Test Year)
- Union: Short-term firm and interruptible transport are not within the supply plan
- Union: holds contracts for diversified supply
- Enbridge: has displaced STFT with FT
- Enbridge: forecasts C$17.2M in UDC for 2014 (EB-2012-0459, Ex. D1, Tab 2, Sch. 1, p.6)
- Enbridge: notes that even with additional UDC, total costs could be less depending on the relative rates of different transport service options, and thus recoverability rules on UDC could impede decisions that would lower costs (see EB-2012-0459, Ex. D1, Tab 2, Sch. 1, p. 14).

v. storage level planning

Storage operating regimes are another large cost-risk trade-off, whose importance is evidenced by this last winter. Storage withdrawal rights are a related parameter.

- Union: full on Nov 1, empty by March 31 (w/ "normal" weather)
- Union: able to meet design day until February 28 ("maximum deliverability")
- Enbridge: able to meet design day until January 31 ("multi-peak")
- Union: 15.0 PJ of TCPL STS withdrawals
- Union: uses Aggregate Excess Storage Method based on normal year to determine base storage requirement

vi. use of peaking supplies

Contracted peaking supplies allow demand not met by specifically planned volumes to be met by contractual purchase option rights

- Union: none forecasted for 2013/14
- EGD plans same level for 2013 as 2014, but will meet with more TCPL FT since planning for STFT is too uncertain with regulatory changes

vii. procurement mechanisms for incremental supply (spot vs. forward market purchases)

Regimes that allow or can accommodate month-ahead purchases are likely to benefit from lower and less volatile prices that those limited to incremental purchasing in the daily or intra-month spot markets

- Union: month-ahead Dawn supply per Gas Procurement Policy and Procedures, see Union QRAM Tab 1, pp. 16-18
- Enbridge: "exposure to daily/intra-month market pricing is driven by plan requirement to manage purchases to meet projected demand and storage deliverability targets" (QRAM, Ex. I, Tab 2, Schedule 1, pg. 3)

viii. Other forecast assumptions

The supply planning process needs to incorporate assumptions on certain variables.

- Assumed transportation tolls are those in effect at the time of forecast.
- Commodity price forecast used is the same as in QRAM process.

d. Commentary

i. Cost and risk trade-offs of relevant gas supply planning parameters

A recurring theme regarding supply planning is the idea that certain risk mitigation measures may have high fixed costs, but low average costs in the event that a risk actually develops. Products with demand charges, such as firm transportation, fall into this category, and would be the preferred option when a risk actually develops. If the risk does not develop, then these products would likely end up costing more than an alternative product with low fixed costs but high average costs in the event that a risk actually develops. Using hindsight to evaluate the "winning" strategy may be interesting, but shouldn't guide future decision making. Having a clear understanding of an entity's risk profile, and the considerations driving that risk profile, is critical to structuring an appropriate risk strategy. Examples of cost-risk trade-offs abound in the supply planning function[13], and include such things as the following:

- Colder design day would increase storage deliverability targets and levels of firm transport, which would cost more but mitigate risks in the event of a colder winter
- Less planned use of peaking services would increase storage deliverability targets and levels of firm transport, which would cost more but mitigate risks in the event of a colder winter
- Higher storage deliverability requirement may cost more, but it also reduces exposure to market pricing

[13] See, e.g., the Board's Decision and Interim Order in EB-2014-0039 (Enbridge Q2 2014 QRAM application), where the Board "acknowledge[d] the differences in the gas purchase options available to Union and those available to Enbridge." The Board noted that differences in Union's and Enbridge's gas supply plans included storage inventory and heating degree day levels, use of peaking service contracts, and balancing requirements for direct purchase customers.

ii. Likely persistence of identified price drivers

Regarding the weather, it should be remembered that predictions are inherently risky and cannot be made with anything approaching certainty. That being said, it would seem that it would not be improbable for Ontario to have another winter with early, persistent or extreme cold. The likelihood of having a winter with all three attributes would be lower, and the likelihood of having a winter with early, persistent and extreme cold, and that is also occurring over a widespread geographic region, lower still. It would be speculative to suggest anything further. It is not apparent what other phenomenon could result in such large, widespread, and persistent gas demand increases.

If the Board seeks to affect commercial decisions (e.g. storage management, transportation tolling, customer balancing) by market participants acting within the terms of their supply plans, the Board could potentially make changes to the gas supply plans or planning parameters.

iii. New or emerging factors that could influence QRAM drivers and prices

There are several on-going trends in North America that we see as key factors in the evolution of market dynamics. The two primary, interrelated trends are the further development of shale gas resources, and the associated expansion of the gas pipeline network to help bring shale gas supplies to markets. Since Ontario, and in particular the Dawn Hub, is a significant market that is well-located with respect to the key shale region in the U.S. Appalachian Basin, the likelihood of Ontario benefitting from a strengthening of supply seems good.

Other potential factors are likely less relevant, but nevertheless could include such trends as changing weather or weather patterns, perhaps as connected to climate change (e.g. impacts hydroelectric availability on electric generation gas demand).

iv. Areas for the Board's consideration

We understand the Board is already involved in many of the factors noted in this review by virtue of its role in reviewing and approving the LDC supply plans. An analysis of the cost and risk trade-offs associated with different decisions regarding these factors could be an area of interest for the Board, bearing in mind that the nature of risk makes it highly unlikely that all risk can be mitigated at reasonable costs.

An additional potential area for consideration is maintaining an on-going awareness of the evolution of supply and demand at Dawn in the near to medium term. As we understand the LDCs to be planning on procuring more gas at Dawn, while on the supply side there are analogous industry moves to increase access at Dawn to developing supplies, we would expect the Dawn supply-demand balance to be an important topic with respect to regulated gas supply for Ontario.

Exhibit “F”

uniongas
A Spectra Energy Company

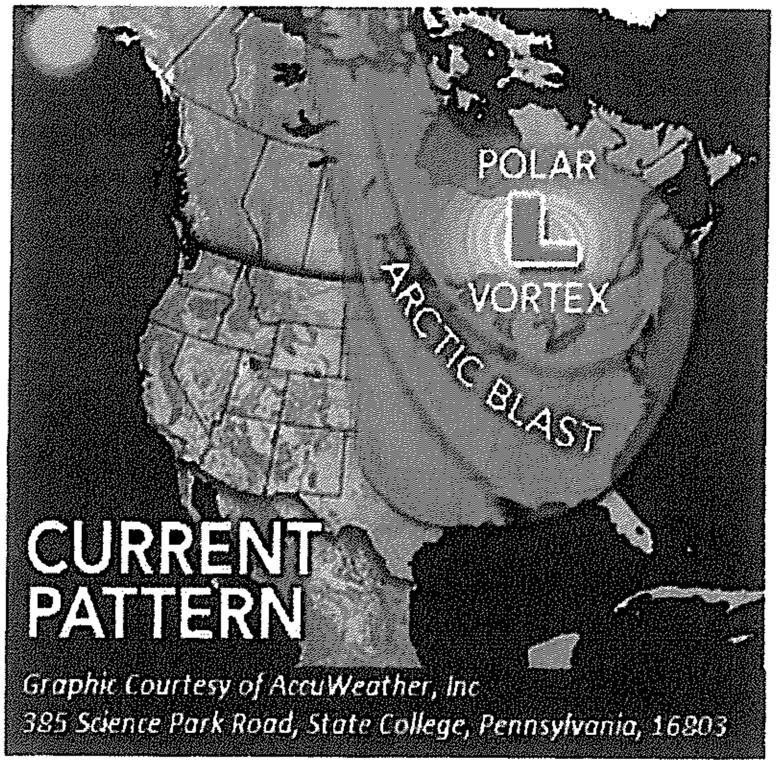
An Exceptional Winter
Serving the Needs of Ontario's Natural Gas Customers

Winter 2013-14

This is Exhibit "F" referred to in the affidavit of Brian Lippold sworn before me, this 25 day of March 2015

A COMMISSIONER FOR TAKING AFFIDAVITS

An Exceptional Winter

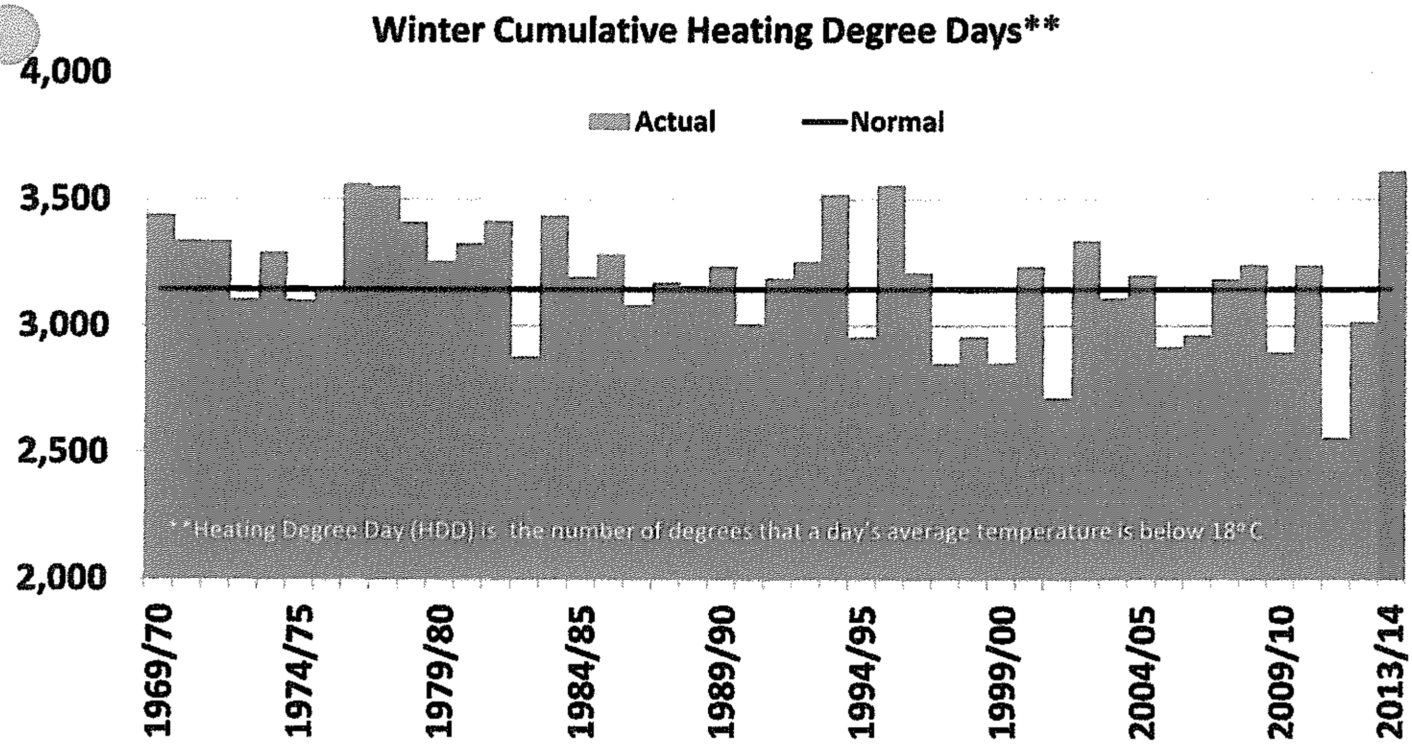


1. **Coldest on record:**
   - Moved from west to east and settled in the eastern half of North America
   - Drove incremental demand
2. **Gas supply contracted to Ontario:**
   - Some gas found lucrative markets upstream of Dawn (i.e. Chicago) reducing supply delivered to Ontario
3. **Incremental Ontario/Quebec demand served by:**
   - Dawn storage withdrawals
   - TransCanada Interruptible and Short Term Firm Services from Alberta on Mainline
4. **Prices:**
   - Remained relatively stable for customers buying for future month delivery
   - Were subject to volatility for customers buying on a daily basis

Sustained record cold weather impacted natural gas demand, flows and pricing across North America

Coldest Winter on Record*

Union Franchise Area



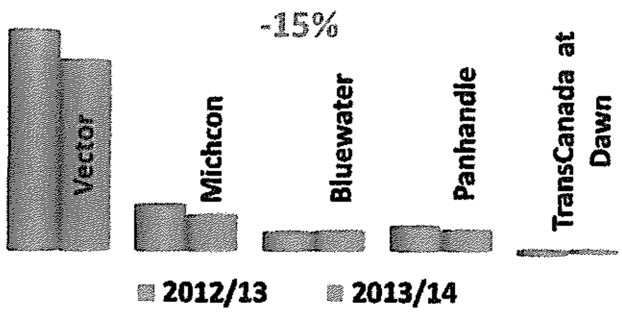
** Union Gas temperatures back to 1969*

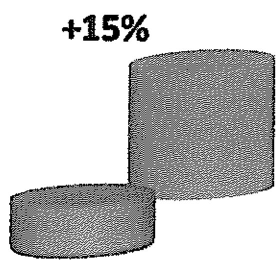
Sustained cold not experienced in at least 45 years

uniongas

Serving Ontario Demand this Winter

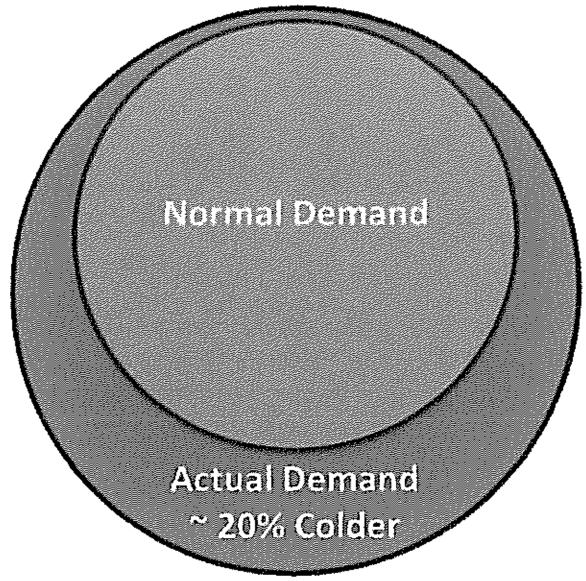
Pipeline Flows into Dawn Decreased





Dawn Storage Made Up the Difference

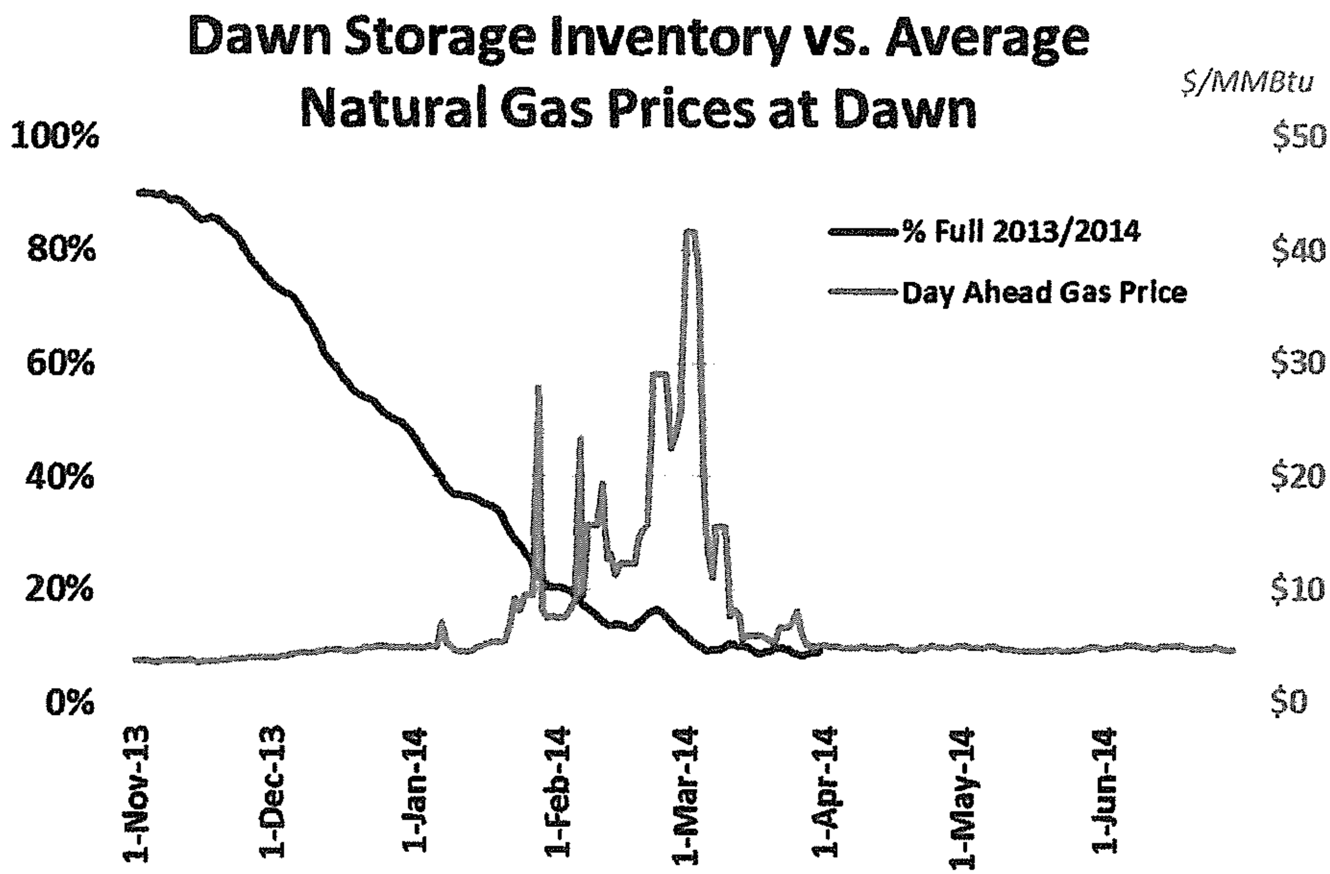
Ontario Gas Demand



Dawn storage was Ontario's workhorse this winter

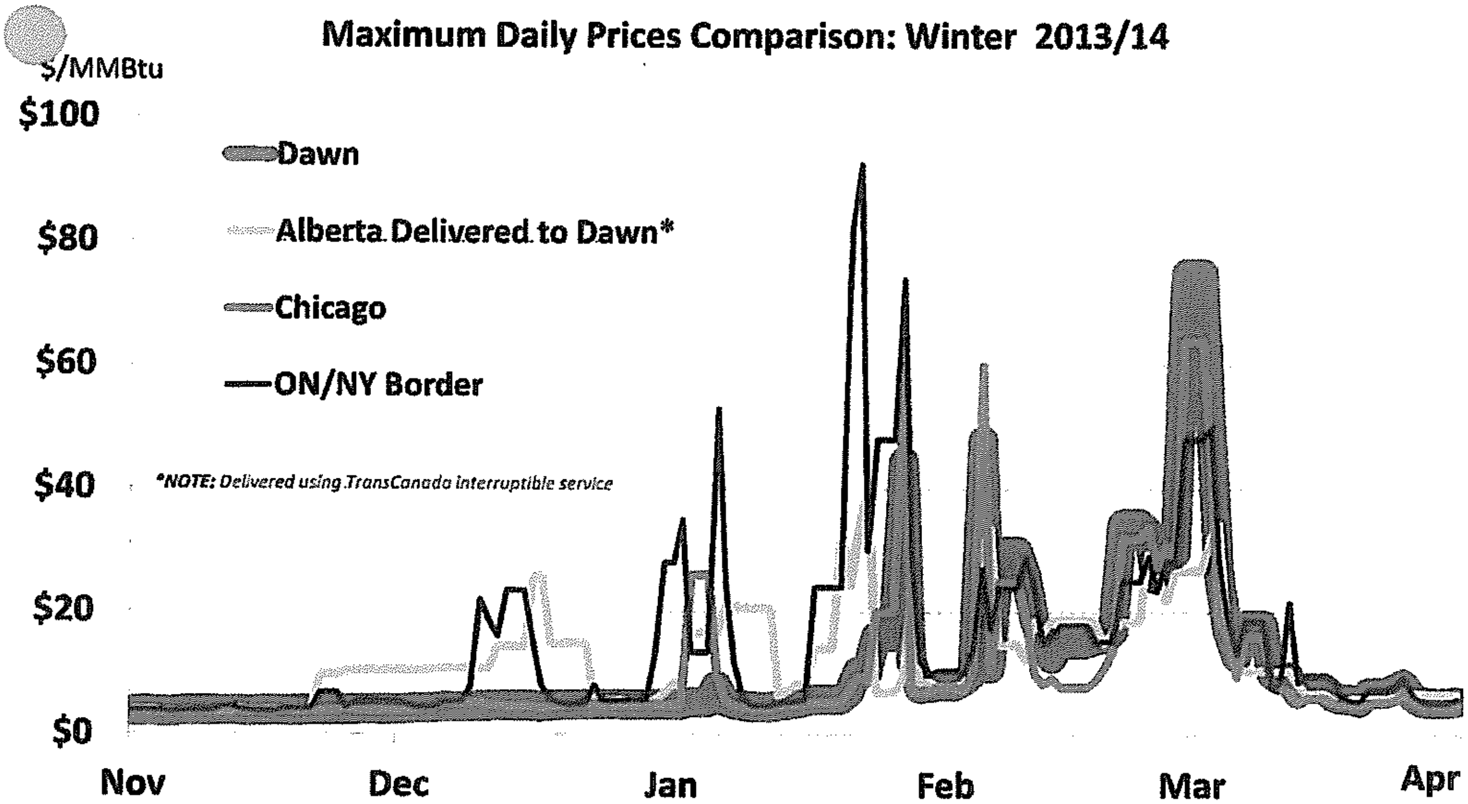
Dawn Storage Availability Offset Price Spikes

unionGas



uniongas

Maximum Daily Prices Winter 2013/2014



Dawn traded lower than Chicago and ON/NY border during the coldest days

Additional Gas Purchased for Customers Supplied by Union

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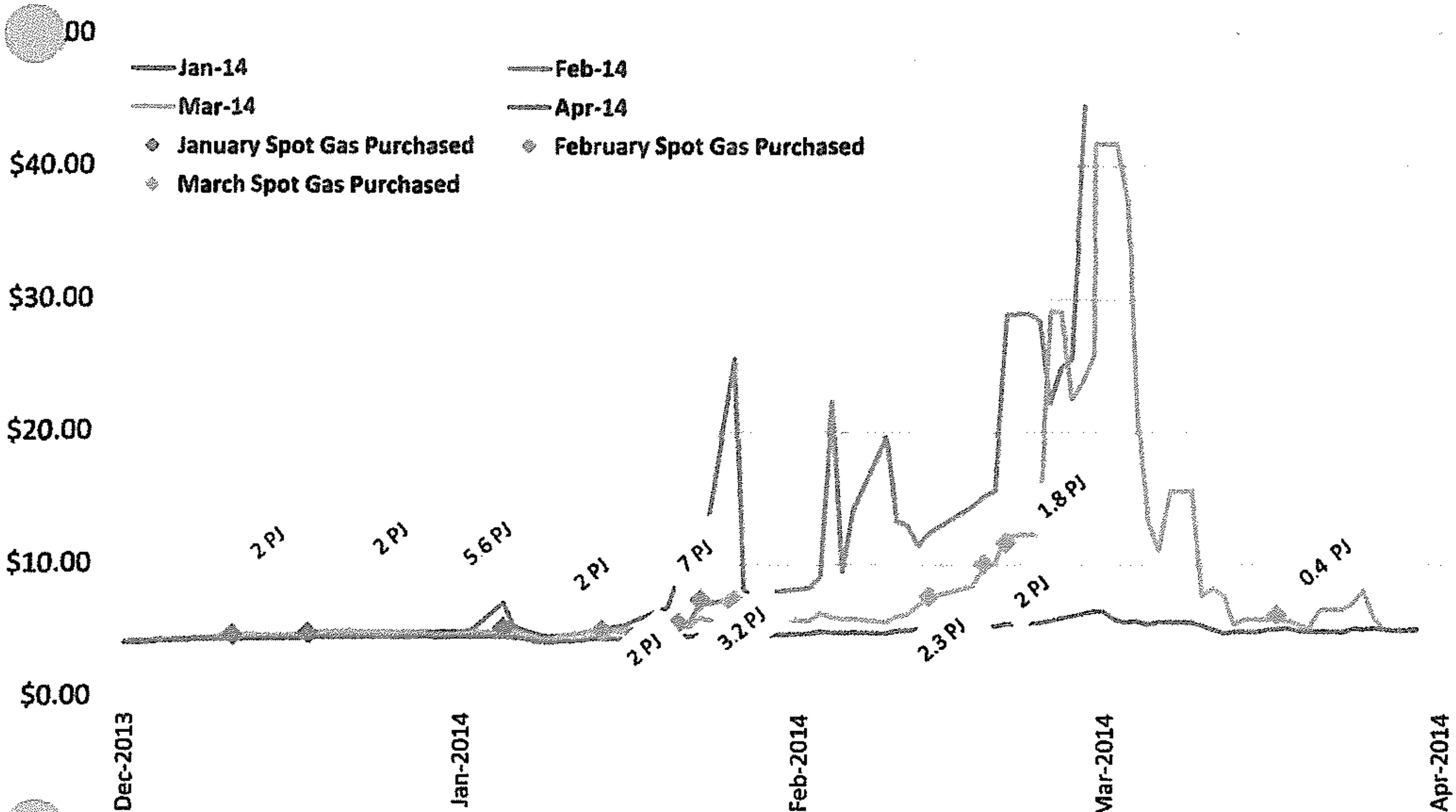

Union Gas managed the price impact to customers by frequently monitoring markets and prices, adjusting purchasing strategy to account for forecast weather impacts and continuing to not rely on the day market

The Cost of Winter – Regulatory Outcomes

- **April QRAM**
  - Prices increased due to:
    - Forward NYMEX 12 month strip (Apr '14 to Mar '15) impact on Reference Price
      - »April 1 ($4.87/GJ to $6.17/GJ)
    - Increased costs of planned January through March purchases (higher than forecast in Jan QRAM)
    - Unplanned spot gas required to meet incremental weather driven demand
      - Union purchased over 30 PJ of spot gas at an average price of approx. $7.12/GJ
- **October QRAM**
  - Prices retreated as storage refilled back to normal levels
    - Reference price decreased from $6.17/GJ to $5.44/GJ (price retreated approx. 60% of April increase)

The Cost of Winter – Regulatory Outcomes cont'd

uniongas
A Spectra Energy Company

- **2013 Deferral Hearing**
  - Costs to balance south bundled direct purchase customers
    - Board ruled that these customers should pay $1.954 million for additional gas Union bought to balance their needs for the period beyond when the Feb 28 checkpoint requirement was calculated
  - Costs of Managing the system including the price variance related to Unaccounted for Gas (UFG)
    - Board ruled all customers who rely on their compressor fuel (bundled Direct Purchase and System supply) from Union should pay a portion of the $4.7 million price variance incurred
- **Winter Penalty Proceeding**
  - The Board approved Union's application, for a one-time exemption from approved tariffs with respect to the penalty charges applied to direct purchase customers who did not meet their contractual obligations during the months of February and March, 2014
  - A reduction in the charge from approx. $78/GJ to approx. $50/GJ

True Impact to Union Sales Service Customers of Winter 2013/14

uniongas

Estimate based on April QRAM

- **Residential annual bill increase for Union Gas system gas customers:**

Annual average use of 82 GJ (equal to 2,200 m3 of natural gas)

Total estimated increase April 2014 – March 2015:	$200
– Due to increased price of planned purchases (Jan-Mar):	**$ 50**
– Due to incremental gas purchases (Jan-Mar):	**$ 40**
– Due to the forward gas price (Apr 2014 to Mar 2015):	$110

- **Revised due to price change based on October QRAM**

Total estimated increase April 2014 – March 2015:	$126
– Due to increased price of planned purchases (Jan-Mar):	**$ 50**
– Due to incremental gas purchases (Jan-Mar):	**$ 40**
– Due to the forward gas price (Apr 2014 to Mar 2015):	$ 36

QRAM Process

- Concerns were raised about QRAM process after last winter
- OEB Initiated a process to review (July QRAM delayed)
  - Many submissions were filed
  - Most concerns centered on communication protocol and early warning of significant changes
  - OEB amended process to communicate early when a significant change in rates is foreseen
- QRAM Process as currently structured is an efficient and effective mechanism
  - Provides customers with market pricing signals, while at the same time, reducing rate volatility
  - Does not require any further changes

Summary Observations

From Coldest Winter on Record

unionGas

Customers received the gas needed this winter as Union's integrated system worked very well

2. Less gas delivered to Ontario, combined with the coldest winter on record meant that Dawn storage was critical in meeting incremental winter needs

3. Dawn storage limited gas price volatility until end of January

4. Union's frequent monitoring and proactive purchasing strategies were critical in managing the cost impact to sales service customers

5. The vast majority of Union's Direct Purchase customers complied with their contractual requirements and ultimately paid the appropriate cost over the winter

Increased access to new supply basins (Marcellus/Utica) is critical to help reduce future price volatility in Ontario

Exhibit "G"

Ontario Energy Board Natural Gas Market Review

Shahrzad Rahbar, PhD
President

December 2014

IGUA | ACIG
www.igua.ca

This is Exhibit "G" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 20 15

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Industrial Gas Users Association

- Members from mining, metals, petrochemicals, pulp & paper and manufacturing sectors
  - Over 24,000 jobs in Canada, 750,000 jobs worldwide
  - Members are in cyclic commodity business
  - Energy costs factor in international competitiveness
- Consumption exceeds 100 PJ per year
- Varied use of gas, varied load profile
  - feedstock, process heat, power generation, space and water heating
  - Main fuel, auxiliary fuel, back-up fuel
- Different gas service combinations
  - From system gas to own transportation and storage
- Heavy reliance on the secondary market
  - Simple, flexible

Our Gas Market Reality

• • •

Last winter, this winter

Going Into Last Winter

- New NEB Tolls for the Mainline
  (source: NEB RH-003-2011 Decision March 2013, Adobe pp20,33-34)
  - $1.42/GJ from Empress to Dawn for firm service (FT)
    firm: annual contract & annual tolls, guaranteed capacity
  - TCPL had asked for $2.52/GJ
  - TCPL full control over the cost of discretionary services
    discretionary: no obligation, pay to use only if excess capacity available
- TCPL priced discretionary services 300% - 500% of firm tolls
  (source: TransCanada Quarterly Surveillance Report for Q4 of 2013)
- Secondary market responded
  - Industrials faced a premium for (secondary market) services
  - Dawn storage did not fill-up

The Cold Winter of 2013-14

- Polar Vortex, prolonged frigid conditions (warmer than design day)
- By February TCPL discretionary services were priced at 1200% of firm
  (source: TCPL Quarterly Surveillance Report for Q1 2014, Adobe p 15)

Gas Prices at Dawn

(source: Union Gas Website, Presentation by Chris Shorts, Natural Gas Market Update and Evolving Supply Dynamics, p 12)

- Winter Strip (Buying in Oct for delivery Nov – Mar) $4
- Month Ahead (Buying monthly for delivery the next month) $4 - $14
- Daily Spot (Buying daily)
  - Nov 2013 range $3 - $4
  - Dec 2013 range $3 - $5
  - Jan 2014 range $4 - $**47**
  - Feb 2014 range $8 - $**79**

Detrimental Impact on Industrials

(IGUA survey)

- Billion dollar order of magnitude hit on markets
  (source: compilation of figures from utility QRAM applications and closing of the books)
- Major energy budget overrun for IGUA members (source: IGUA survey)
  - Gas budget overruns up to 300%, typically in the range 5%-15%
  - Electricity budget impact up to 480%, typically in the range 15%-30%
- High curtailments
  - 20+ days in Ontario (50+ days in Québec)
- Impact severity varied with location, load profile & service type
  - Secondary market, direct contracted capacity, through the LDC
- Polar Vortex can not be blamed for everything
  - New toll regime, low storage, competition from US power market

Outlook for the 2014-2015 Winter

- Normal BAU projections for demand, infrastructure and supply
- Dawn storage is full
- Discretionary services priced lower than last year (95%-300% of FT)

However

- Higher cost & fewer services offered in the secondary market
  - Member could not secure winter supply for Enbridge EDA from the secondary market and was asked to buy daily
  - Member in Union SWDA (almost on top of Dawn) paid a 20% premium
- The forward price of winter supply at Iroquois is twice the forward price of supply at Dawn
  - Basis differential is nine times the transportation cost, suggesting constraint
- Buffalo got 5 ft of snow in November…

Evolution of Natural Gas Markets

Supply, Infrastructure, Demand

Supply – Dramatic Change

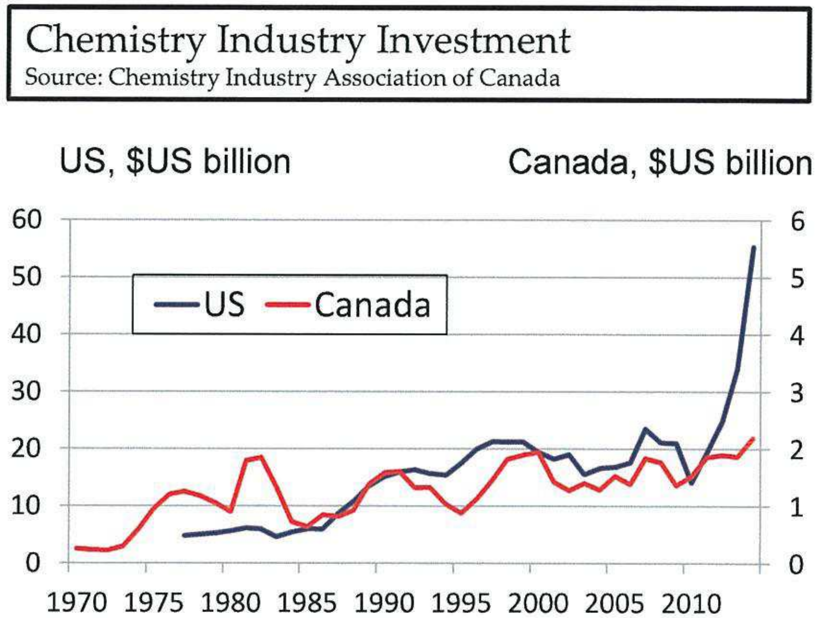
- Within 5 years North America has gone from 'short' to 'surplus'
- ON is close to Marcellus and Utica (larger than WCSB)
- Dawn storage is a major asset for Ontario

Opportunity for ON … investment, jobs, quality of life

- Reduce the landed cost of gas & electricity
- Enhance competitiveness of ON industry
- Attract new investment and grow the economy
- Develop the ring of fire

Demand

- Stagnant res/com
- Steady growth in power generation
- Emerging transportation
- Industrial
  - Stagnant in ON
  - <u>Manufacturing revival in the US</u>



Data estimated for 2013, projected for 2014

Infrastructure must Adjust

- We recognize that changing the architecture of the gas infrastructure is non-trivial & entails cost
- Emerging flow configurations will shape trade & investment patterns for several decades
  - Energy enables economic development
  - Industrials need access to reliable and competitively priced energy to survive, compete & grow
  - Timing is important
  - Market redesign should reflect the price sensitivity of market demand
- Managing the transition is important
  - Properly considered but…reasonably expeditious
  - Coordinated (bigger picture) view
  - Costly lost opportunity otherwise

ON Infrastructure Needs

- US pipeline construction to connect new supply **to** Dawn
- Enhanced physical and financial liquidity at Dawn
- Removal of pipeline bottlenecks **from** Dawn to markets
- Redefined role and tolls for the Mainline
  - Continues to be very important for security & diversity of supply
- Manage the cost of stranded Mainline assets
- Efficient and smooth transition process

Infrastructure Adjustment

Piecemeal, Inefficient and Expensive

Industrial Market Expectations

- Turn proximity to Marcellus into competitive advantage
- Long term
  - Reduced landed cost of gas in Ontario
  - Expanded physical and financial liquidity at Dawn
  - Right-sized pipeline system
- Short term
  - Avoid price shock and service deterioration
  - Road map for infrastructure transition
  - Smooth transition process

Transitioning the markets should not be detrimental to markets

Transition Update

- Bottlenecks – NEB decision?
- Stranded Asset Issue – Energy East application was filed late October
  - Will go to hearing in late 2015… currently fiercely opposed
  - NEB process limits broad public engagement
  - ON and QC governments have stepped in to engage & represent the public
- Domestic gas market interests are pitted against oil export interests unnecessarily
- Insufficient attention to:
  - The status of pipelines connecting new supply to Dawn
  - The need for enhanced financial liquidity at Dawn
- The economic revival witnessed in Michigan, Ohio and Pennsylvania is sadly lacking in QC and ON

Costly & Painful Process

- Fierce fighting among the pipeline majors
- Many different hearings in multiple jurisdictions deal with aspects of the transition (NEB, OEB & the Régie)
- Regulatory system is strained under the magnitude, scope and pace of change
- Media tug-of-war, stepped up lobbying
- Secondary markets offer less service at higher cost
- Lumpy industrial investment is going to the US

Harmful to competitiveness … Missed economic opportunity

Timely Gas Market Review

Last winter, long term, Information gap

Recovering from Last Winter

- Restore confidence in the market
  - Investigate the events and ensure all parties followed the 'rules'
  - Examine the adequacy of the 'rules'
- Safeguard against last winter becoming the new norm; **Identify** and **monitor** key influencers
  - Gas storage and pipeline capacity
  - The interdependence between gas and electricity markets
  - Interplay between domestic and export markets
  - Secondary market dynamics
  - More volatile weather patterns
- Facilitate better information in the market place
  - Annual natural gas deliverability report, periodic updates
- Replicate FERC's gas market monitoring role in Canada (NEB?)

Mid to Long-Term Objectives

Consider both extra-jurisdictional developments and broader/longer term transition to new market configuration

- Streamline the infrastructure transition process
  - Consideration for how any specific application fits in the global transition process
- Facilitate supply diversity
  - Ensure timely removal of pipeline bottlenecks **from** Dawn to markets
  - Ensure that ON gas markets are served after repurposing of stranded Mainline assets
  - Develop a perspective of the evolving role of the Mainline and a suitable toll regime
- Ensure the transition is not detrimental to markets
  - Avoids price shocks
  - Foster a vibrant secondary market

Regulators, applicants and intervenors share responsibility for facilitating consideration of the bigger picture

IGUA and Energy East

- Enthusiastic about the concept of the project
  - Leverages Canadian energy resources to strengthen the industrial base in Canada
  - Brings new life to the petrochemical industry
  - Repurposes underutilized gas assets
- Support the transfer of underutilized assets from Empress to North Bay
- Issues with the transfer of the utilized North Bay Short cut
- We should find a way to build the Energy East pipeline without harming gas markets

Thank You

Exhibit “H”

This is Exhibit "H" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 2015

A COMMISSIONER FOR TAKING AFFIDAVITS

UNION GAS LIMITED

Answer to Interrogatory from
Natural Resource Gas Limited

Reference: NRG / Union Contract and Requests of Union for Assistance

In February, 2014 NRG sought assistance from Union regarding its obligations to provide natural gas for balancing purposes. In its rate and services conditions, Union speaks of an In-Franchise Transfer contract. An In-Franchise Transfer contract moves gas from an in-franchise contract that is "long" (over delivered) to an in-franchise contract that is "short" (over consumed). Union permits IFTs between customers in any delivery area according to its rates and services conditions. Union suggested a customer to speak with that might be long or have gas for purchase, but that contact did not return NRG's call. Union otherwise said it had no assistance to offer NRG. Are the above facts as stated correct? Was any other assistance available, but refused by Union? Was Union able to supply the natural gas itself from the amount it had already purchased or contracted to purchase? If so, why did Union refuse to assist NRG? In this regard, is there a difference between assistance rendered to a utility as opposed to any assistance rendered to a strictly commercial customer? Please explain.

Response:

Union did not refuse to assist NRG. During January and February 2014 Union frequently communicated with NRG to notify it of its balancing obligations, responded to NRG's emails and telephone calls, provided a written response on February 24th to their NRG's letter dated February 21st (Please see Attachment 1 and Attachment 2) and participated in a conference call with NRG representatives on February 26th. This was done to assist NRG in understanding and meeting its contractual obligations and included the discussion of gas supply options. Union provided options to NRG to meet its checkpoint obligations, including:

(i) purchase the gas in the market itself per its normal practice;
(ii) purchase from an in-franchise contract that is "long" (In-Franchise Transfer - IFT); or,
(iii) purchase gas through Union via its Discretionary Gas Supply Service.

As communicated to NRG, Union could supply the natural gas as part of the Discretionary Gas Supply Service ("DGSS"), which is a supplementary gas supply service of last resort for Union South Direct Purchase customers. Union South Direct Purchase contract customers, who are unable to access market supplies from other sources, can purchase supplementary gas directly from Union through the DGSS to meet their unplanned, excess consumption. Gas purchased through this service will reflect market pricing, as well as an administration fee. The administration fee that Union charges for this service is the same as that approved for sales service gas sales. NRG did not request this service from Union.

The advice provided by Union is the same offered to other customers and is the extent of the assistance from Union that is available with regard to acquiring gas to meet their balancing obligations. Further, it is the same assistance that is provided to direct purchase customers, regardless of whether they are a utility, retail energy marketer or commercial customer.

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

Via Email

February 21, 2014

Mr. Patrick Boyer
Union Gas Limited

Bundled-T Gas Contract between NRG and Union

We are writing to request that Union waive any rights it may have to require NRG to purchase natural gas before February 28, 2014 in order to meet NRG's Winter Checkpoint Quantity of -115,000 GJ. In the absence of any such waiver, NRG will have to consider bringing an emergency application to the Board to obtain such relief. We would be pleased to discuss an alternative future point for balancing this contract year.

The reasons for this request are straightforward:

- Natural gas prices at Dawn today are in the neighbourhood of $38 per GJ, which is an anomaly.
- You have notified us that although the Winter Checkpoint Quantity date is February 28, Union needs the transaction completed by Monday, February 24, 2014.
- The relief being requested by us provides no benefit to NRG or its shareholder, since natural gas commodity is a pure pass through at the market price. However, the contractual relief being requested would be of significant financial benefit to residential and small business customers in NRG's service area. We estimate buying gas today would cost a typical residential customer of NRG about $300 extra over the next 12 months (as compared to purchasing at a more typical price).
- As a utility, NRG understands the need for balancing its physical system. But NRG does not believe that the balancing gas to be provided by NRG is needed for any system security or reliability reasons of Union. So there is no real benefit to Union to enforce the Winter Checkpoint requirement. And there is, as noted above, an exorbitant cost to NRG's customers. Indeed, the cost borne by NRG's customers would be of no benefit to anyone, other than the selling gas producer.

Yours truly,

B Lippold

Brian Lippold,
General Manager

Copy: D. Simpson (Union Gas)
M. Aldred (OEB)
R. King (Osler)

uniongas
A Spectra Energy Company

February 24, 2014

Natural Resource Gas Limited
39 Beech St. E.
P.O. Box 307
Aylmer, ON
N5H 2S1

Attn: Brian Lippold, General Manager

Re: Request to waive NRG's Winter Checkpoint Obligation

Dear Mr. Lippold;

Union Gas Limited ("Union") has received your letter dated February 21, 2014, requesting that Union waive Natural Resource Gas Limited's ("NRG") Winter Checkpoint Obligation.

For the reasons below, Union cannot waive NRG's Winter Checkpoint Obligation. As per the terms of the Southern Bundled Transportation Contract, **NRG is required to submit a balancing transaction for 115,523GJ by 4:30 p.m. ET on Monday, February 24, 2014, with delivery of gas to its Banked Gas Account ("BGA") by Friday February 28, 2014.** This balancing transaction reflects the amount of gas that NRG has consumed above the forecasted level of consumption anticipated in your contract. If not immediately corrected, this imbalance will result in a shortfall on Union's distribution system that cannot be tolerated.

The reasons Union cannot waive NRG's Winter Checkpoint Obligation are:

- NRG has elected to provide its own gas supply to meet consumption needs and entered into a Southern Bundled Transportation Contract with Union. The contract sets the terms and conditions of this service, including the Winter Checkpoint Obligation. The Winter Checkpoint Obligation is to ensure that Bundled Direct Purchase customers are fully accountable for any consumption in excess of the forecasted consumption contained in their contract, up to and including February 28, 2014. While Union provides services to enable the direct purchase market, it remains NRG's responsibility to ensure its BGA balance is not in excess of the contracted Winter Checkpoint. If the weather is different than expected for February of any year, and/or the consumption in the contract is higher than forecasted in March, Union will purchase gas to eliminate those variances and bill that cost to customers as well.

- The Winter Checkpoint Obligation, which has been in place since 2004 (OEB RP-2003-0063), is integral to the security of supply and reliability of Union's system. Ensuring that sufficient gas supply is available at the end of February is a critical control point for Union's system. Contrary to NRG's position, any customer's failure to meet their obligation impairs Union's system and exposes the utility and its customers to a supply shortfall. This creates an operational risk and generates incremental costs to address the customer's failure to deliver the required gas.

- The Winter Checkpoint Obligation is well defined in the Southern Bundled Transportation Contract. Another requirement is for the customer to pro-actively manage their BGA during the contract year. NRG's failure to manage its BGA when increased consumption began occurring in November 2013 is not a justifiable reason to waive the Winter Checkpoint Obligation in the last week of February 2014. NRG has had the flexibility all winter to purchase and deliver incremental gas to reflect the colder than normal weather this winter. Union, for example, has been purchasing incremental gas to reflect the increased consumption for system customers starting in December and continuing each month since. As well, other direct purchase customers with the same contract as NRG have been delivering gas to meet their Winter Checkpoint Obligation.

- NRG's reference to the spot gas prices at Dawn and assertion of a negative impact on its customers is not relevant to the Winter Checkpoint Obligation. Certainly a colder than normal winter has impacted gas prices and consumers across Ontario, including Union's own customers. However, as Union's other Southern Bundled Transportation contract holders are meeting their obligations, providing an exception to NRG would be neither equitable nor appropriate. Furthermore, providing an exception for NRG would support the very behaviour that the Winter Checkpoint Obligation is designed to dissuade.

Please note that if this obligation is not met, NRG is contractually required to purchase the balancing gas from Union at the highest daily spot gas price recorded at Dawn in either February or March 2014. With the highest spot price to date in February at $50.50/GJ, should NRG default on its Winter Checkpoint Obligation, Union would be required to supply the balancing gas and invoice NRG $5,833,911 for same. Given the $50.50/GJ already recorded, and the possibility for higher prices to occur during the rest of February or in March, NRG is strongly encouraged to make its own supply arrangements as soon as possible.

Should you have any further questions, please contact your account manager, Patrick Boyer.

Sincerely,

Jim Laforet, Manager Contract Billing & Operational Support

Copy:
Dave Simpson, Union Gas
Patrick Boyer, Union Gas
Mark Kitchen, Union Gas
Mary Anne Aldred, Ontario Energy Board
Richard King, Osler, Hoskin & Harcourt LLP

Via Email

Exhibit “I”

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2014-0154

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations.

Before: Ken Quesnelle
Presiding Member and Vice Chair

Marika Hare
Member

This is Exhibit "I" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 20 15.

A COMMISSIONER FOR TAKING AFFIDAVITS

DECISION AND ORDER
October 9, 2014

Introduction

Union Gas Limited ("Union") filed an application dated April 3, 2014 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B, for an order of the Board approving a one-time exemption from its approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations during the months of February and March, 2014.

The major procedural steps of this proceeding are provided in Appendix "A".

Background

In its application, Union requested that, on a one-time basis, the penalty charges applied for Rate T1 / T2 Supplementary Inventory and Rate 25 Unauthorized Overrun Gas Commodity in February and March, 2014 be reduced. In addition, Union requested that the penalty charge applied to bundled T-Service customers that did not meet their contractual balancing obligations in February 2014 be reduced in the same manner.

To date, customers that were not in compliance with their contractual obligations in February and March, 2014 were applied penalty charges based on the highest daily spot cost of gas at Dawn in the month of or the month following the month in which the gas was sold, all of which is in accordance with Board approved rate schedules.

Union's proposal, as set out in its application, would reduce the noted penalty charges to the second-highest spot cost of gas at Dawn in the month which the gas was sold.

The effect of Union's proposal is to reduce the penalty charges for customers that did not meet their contractual obligations in February 2014 from $78.73 / GJ to $50.50 / GJ. For customers that did not meet their contractual obligations in March 2014, Union's proposal would reduce the penalty charges from $78.73 / GJ to $52.04 / GJ.[1]

Position of Parties

In its argument-in-chief, Union stated that it is proposing to reduce the penalty charges in recognition of the exceptional weather conditions experienced during the winter of 2014. Union noted that the five-month winter period from November 2013 to March 2014 was the coldest in Union's records (which date back to the 1969 / 1970 winter) for its southern service area.[2]

Union submitted that it applied for the one-time exemption from the Board-approved rate schedule based on feedback from customers most affected by the penalty charge. Union noted that, specifically, the impact is significant for four customers that were facing a charge in excess of $800,000. Union stated that for these four customers, the impact could result in impairment of their financial viability.[3]

Board staff, AMCO, APPrO, BOMA, CME, NRG, OGVG, and TCE all submitted that the penalty charges should be reduced in the context of the exceptional weather conditions experienced during the 2014 winter.

[1] Union Application, EB-2014-0154, April 3, 2014.
[2] Union Argument-in-Chief, EB-2014-0154, September 2, 2014 at p. 2.
[3] Ibid at p. 3.

Board staff, BOMA and OGVG agreed with Union's proposed reduction to the penalty charge. Board staff argued that the reduced penalty charges, as proposed by Union, continue to encourage compliance with the contractual obligations applicable to Union's direct purchase customers in the context of the exceptional weather conditions experienced over the 2014 winter.[4] As such, Board staff submitted that "the reduction to the penalty charges, as proposed by Union, adequately balances the competing issues of the intent of the penalty charges and providing financial relief to customers that are significantly harmed by the application of those charges."[5]

AMCO stated that while Union's proposed reduction of the penalty charge is a positive effort, it requires a further review to ensure that the penalty will not impose extended hardship on Union's customers.[6]

CME argued that the extraordinary circumstances of the 2014 winter justify a reduction to the penalty charges. CME stated that the level of the reduced penalty charges should not be less than the price paid by compliant customers to meet their contractual obligations.[7]

NRG also agreed that a reduction to the penalty charges is warranted given the exceptional weather conditions experienced over the 2014 winter. However, NRG argued for an alternative penalty charge that would only be applicable to NRG, as it is a distributor and unlike the other customers who purchase their own gas. NRG stated that the Board should consider setting a penalty rate for NRG in the range of $4.87 / GJ to $7.12 / GJ.[8] [9] NRG stated that the penalty rate should be fixed on the basis of historic norms, Union's actual costs and facts specific to NRG (i.e. that NRG is a distributor and that it did everything it could to meet its contractual obligations).[10]

TCE submitted that Union's proposal to reduce the penalty charge to the second highest spot price at Dawn does not address the issue of determining what a reasonable penalty charge would be in light of the weather conditions experienced over the 2014 winter. TCE submitted that setting the penalty rate at the second

[4] Board Staff Submission, EB-2014-0154, September 12, 2014 at p. 3.
[5] Ibid at p. 2.
[6] AMCO Submission, EB-2014-0154, September 12, 2014 at p. 2.
[7] CME Submission, EB-2014-0154, September 12, 2014 at p. 1.
[8] NRG also mentioned that the maximum penalty that it should be applied is $12.31 / GJ.
[9] NRG Submission, September 12, 2014 at p. 14.
[10] Ibid at pp. 6-8.

highest price at Dawn is arbitrary and continues to result in an unreasonably high penalty charge.[11]

TCE argued that the penalty charge applicable to T2 customers should be calculated on the basis of Enbridge Gas Distribution's ("Enbridge") methodology for calculating the charges associated with Unauthorized Supply Overrun for Rate 125 customers. TCE stated that its proposed alternative methodology for calculating the penalty charge for T2 customers: (a) fully respects the underlying rationale for the penalty charge (i.e. encouraging contractual compliance); (b) is principled from a rate-making perspective, because it reflects the spot price of gas on the day that the customer exceeded its volumes, thereby strengthening the link between the violation and cost consequences; (c) has been utilized by the Board elsewhere; and (d) results in a penalty charge that is reasonable in magnitude.[12]

APPrO supported TCE's alternative proposal for the calculation of the penalty charge applicable to T2 customers. APPrO also supported Union's proposed reduction to the penalty charges applicable to the other rate classes. In addition, APPrO stated that the penalty mechanism in place did not produce the desired results and that the penalty charges were overly punitive given the circumstances. On that basis, APPrO submitted that the Board may wish to consider directing Union to revisit the penalty provisions in its tariffs in order to asses alternative penalty mechanisms and bring forward its assessment (including any recommended changes) in its next rates proceeding.[13]

IGUA and LPMA submitted that Union's proposal should be rejected and that no reduction to the penalty charges should be approved. Both argued based on the principle that it is wrong to change the "rules" after-the-fact. LPMA argued that if the Board disagrees and does reduce the penalty, it should be in accordance with Union's proposal.

IGUA submitted that it would be inappropriate for a compliant customer to pay more than a non-compliant customer to meet its contractual obligations. IGUA argued that if Union's proposal is approved as filed, it is possible that some compliant customers will have paid more than non-compliant customers to meet their contractual obligations.[14]

[11] TCE Submission, September 12, 2014 at p. 5.
[12] Ibid at pp. 7-9.
[13] APPrO Submission, EB-2014-0154, September 12, 2014 at pp. 3-4.
[14] IGUA Amended Submission, EB-2014-0154, September 15, 2014 at p. 2.

LPMA submitted that the intent of the penalty charge may be compromised by the Board approving Union's proposed one-time reduction to the penalty charges. LPMA stated that direct purchase customers may expect, or seek, future one-time reductions if other exceptional circumstances arise. LPMA submitted that "this expectation could result in exactly the type of economic decision making that the Board has indicated needs to be discouraged in order ensure that the utility system is not put at risk."[15]

BOMA, CME and OGVG also made submissions regarding the appropriate allocation of the amounts arising from the application of the penalty charges.

In response to the submissions of the intervenors that argued that its proposal should be rejected, Union stated that the benefit arising from reducing the penalty charge is greater than the inequity that could result if a few compliant customers paid more to meet their balancing obligations.[16]

Union also submitted that TCE's alternative proposal should be rejected. Union, in agreement with a Board staff argument, stated that TCE's proposal reflects a fundamental change in the manner in which the Supplementary Inventory Charge is calculated and that this type of fundamental change is not appropriate in the context of a request for a one-time reduction of the penalty charge. Union submitted that the type of change proposed by TCE would be best dealt with in a rates proceeding.[17]

Finally, Union submitted that the arguments of NRG should be rejected as they are either not accurate or not relevant to the proceeding.[18]

Board Findings

The Board approves Union's application, as filed, for a one-time exemption from its approved tariffs with respect to the penalty charges applied to direct purchase customers who did not meet their contractual obligations during the months of February and March, 2014 for the reasons set out below.

The intent of the penalty charges at issue in this proceeding was set out by the Board in the RP-2001-0029 Decision with Reasons.[19] Essentially, the penalty

[15] LPMA Submission, EB-2014-0154, September 12, 2014 at p. 3.
[16] Union Reply Submission, EB-2014-0154, September 19, 2014 at p. 2.
[17] Ibid.
[18] Ibid at p. 3.
[19] Decision with Reasons, RP-2001-0029, September 20, 2002.

charges were designed to encourage direct purchase customers to comply with their contractual obligations in order to ensure the security of Union's system. Specifically, the RP-2001-0029 Decision with Reasons set out the following:

> In the Board's view, the penalty must be sufficiently costly to defaulters to strongly discourage strategic non-compliance with balance obligations, and the careless or incompetent acceptance of contractual obligations which are not reasonably achievable. The Board is concerned that parties wishing to engage in the market, either directly or through agents, must be appropriately encouraged to manage their obligations responsibly. The system as a whole requires that.[20]

The Board is of the view that Union's proposed reduction of the penalty charges to the second-highest spot cost of gas at Dawn in the month which the gas was sold is appropriate considering the exceptional circumstances that affected customers during the winter of 2014. The 2014 winter was extraordinary and it is in the context of this anomalous winter that the Board is granting Union approval to reduce the penalty charges. This is an unprecedented step by the Board, and should not be seen as an invitation to utilities or their customers to seek a reduction in penalty charges in general. The Board finds that in this case, the reduced penalty as proposed by Union continues to achieve the intent of the penalty charges as established by the Board in RP-2001-0029. The penalty charges are designed to encourage compliance with contractual obligations. This can be achieved while at the same time reducing the potential for the penalty to unduly impair the financial viability of those required to pay it. The Board considers Union's proposed penalty to be appropriate in striking this balance.

The Board notes some parties argued that it would be inappropriate for a compliant customer to pay more than a non-compliant customer to meet its contractual obligations. In response to this argument, the Board notes that none of Union's direct purchase customers came forward in this proceeding to claim that they actually bought gas to meet their contractual obligations at a price higher than the reduced penalty charges proposed by Union. While the Board recognizes that it is possible that some direct purchase customers may have paid more than the second-highest spot cost of gas at Dawn for gas purchased in order to meet contractual obligations, the Board is of the view that the number of customers, if any, is likely very small and agrees with Union that the benefit arising from reducing the penalty charges is greater than the inequity that could result if a few compliant customers paid more to

[20] Ibid at p. 31.

meet their balancing obligations. In addition, the Board notes that any bundled T-service customer that would have paid $78.73 / GJ for natural gas to meet its contractual balancing obligations would have waited until the last day of February to purchase the gas (as the spot price of gas at Dawn was at its highest on February 28th). The second-highest spot cost of gas at Dawn ($50.50) occurred on February 5th and customers received their Direct Purchase Status Reports on February 12th or 13th.[21] Between the time that customers received their Direct Purchase Status Reports and February 28th, spot prices were below $50.50. This is indicative of the choices customers had to purchase gas, in order to meet contractual obligations, at prices below $78.73 / GJ (and, in fact, below $50.50).

With respect to TCE's proposal that the penalty charge applicable to T2 customers should be calculated on the basis of Enbridge's methodology for calculating the charges associated with Unauthorized Supply Overrun for Rate 125 customers, the Board rejects this proposal on the basis that it reflects a fundamental change in the manner in which the penalty charge is calculated. The Board does not believe that a fundamental change of this nature is appropriate in the context of Union's request for a one-time reduction of the penalty charge.

The Board does not find NRG's arguments concerning a different method to setting the penalty convincing. Neither is the argument concerning NRG's special situation accepted. The Board finds that setting the penalty charge that is to be applied to NRG on the basis of historic norms or Union's gas costs is not appropriate and not consistent with the intent of the penalty. In addition, the Board is of the view that, in this matter, NRG's status as a distributor does not warrant any different treatment. As such, the Board finds that the same reduced penalty, as proposed by Union, which will be applied to all of the non-compliant customers, shall also be applied to NRG.

The Board will not make any findings regarding the appropriate allocation of the excess amounts arising from the application of the penalty charges in this proceeding. The Board notes that this allocation issue is currently before the Board in Union's 2013 Deferral Account Disposition proceeding (EB-2014-0145).

The Board directs Union to implement the outcome of this decision as soon as reasonably possible.

[21] Union Interrogatory Responses, EB-2014-0154, June 19, 2014 at Exhibit B / Staff IRR #1.

Cost Awards

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied. The Board notes that filings related to cost awards shall be made in accordance with the schedule set out below.

THE BOARD ORDERS THAT:

1. Union is granted a one-time exemption from its approved tariffs with respect to the penalty charges applied to direct purchase customers who did not meet their contractual obligations during the months of February and March, 2014.

2. Union shall apply the approved reduced penalties ($50.50 / GJ for February and $52.04 / GJ for March) to its customers as soon as reasonably possible.

3. Eligible intervenors shall file with the Board and forward to Union their respective cost claims within 14 days of the date of this Decision and Order.

4. Union shall file with the Board and forward to the intervenors any objections to the claimed costs of the intervenors within 21 days from the date of this Decision and Order.

5. If Union objects to the intervenor costs, intervenors shall file with the Board and forward to Union any responses to any objections for cost claims within 28 days of the date of this Decision and Order.

6. Union shall pay the Board's costs of, and incidental to, this proceeding immediately upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2014-0154**, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available you may email your document to the BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies. If you have submitted through the Board's web portal an e-mail is not required.

For all electronic correspondence and materials related to this proceeding, parties must include in their distribution lists the Case Manager, Lawrie Gluck at Lawrie.Gluck@ontarioenergyboard.ca and Counsel, Jennifer Lea at Jennifer.Lea@ontarioenergyboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than **4:45 p.m.** on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

Filings: https://www.pes.ontarioenergyboard.ca/eservice/
E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, October 9, 2014

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

TO DECISION AND ORDER

HEARING PROCESS

BOARD FILE NO. EB-2014-0154

DATED: October 9, 2014

Appendix A – Hearing Process

On May 27, 2014 the Board issued Procedural Order No. 1 which provided for the filing of interrogatories and intervenor evidence, among other things. Union filed responses to the interrogatories on June 17, 2014 (and updated responses on June 19, 2014).

On June 20, 2014 the Board received a motion from the intervenor TransAlta Corporation ("TransAlta") under section 27 of the Board's *Rules of Practice and Procedure*. The motion sought an order requiring Union to provide full and adequate responses to a number of interrogatories. In its motion, TransAlta also requested a delay in the date for the filing of intervenor evidence.

In Procedural Order No. 2, issued on June 23, 2014, the Board determined that the motion should be heard in writing, and that it would delay the filing of intervenor evidence and subsequent procedural steps until a decision on the motion was rendered. The Board also set out the timeline for the filing of submissions on the motion.

The Board issued its Decision on Motion and Procedural Order No. 3 on July 29, 2014. The decision on the motion dismissed TransAlta's motion and scheduled dates for the filing intervenor evidence and argument of Union and intervenors.

On August 7, 2014, intervenor evidence was filed by TransCanada Energy Ltd. ("TCE") and Natural Resource Gas Limited ("NRG"). Board staff filed interrogatories related to TCE's evidence on August 11, 2014 and TCE provided responses to those interrogatories on August 21, 2014.

Union filed its argument-in-chief with the Board on September 2, 2014. Board staff and intervenors filed their submissions with the Board on September 12, 2014. The Board received submissions from the following parties: Board staff, the AMCO Group ("AMCO"), the Association of Power Producers of Ontario ("APPrO"), the Building Owners and Managers Association ("BOMA"), the Canadian Manufacturers and Exporters ("CME"), the Industrial Gas Users Association ("IGUA"), the London Property Management Association ("LPMA"), NRG, the Ontario Greenhouse Vegetable Growers ("OGVG"), and TCE. Union filed its reply submission on September 19, 2014.

Exhibit “J”

Court File No. 521/14

(Ontario Energy Board)
File No. EB-2014-0154

ONTARIO
SUPERIOR COURT OF JUSTICE
(DIVISIONAL COURT)

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF a Decision and Order of the Ontario Energy Board dated October 9, 2014 on the Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations;

AND IN THE MATTER OF the Intervenor – Natural Resource Gas Limited

BETWEEN:

NATURAL RESOURCE GAS LIMITED

Moving Party/Appellant

- and -

THE ONTARIO ENERGY BOARD and UNION GAS LIMITED

Respondents

NOTICE OF MOTION

Natural Resource Gas Limited ("NRG") will make a motion to the Divisional Court on a date to be fixed by the Court at Osgoode Hall, 130 Queen Street West, Toronto.

PROPOSED METHOD OF HEARING:

The motion will be heard orally.

This is Exhibit "J" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 2015.

A COMMISSIONER FOR TAKING AFFIDAVITS

THE MOTION IS FOR:

1. An extension of time to perfect this appeal until 30 days after the Ontario Energy Board (the "**Board**") has finally decided NRG's motion for a review of the Board's Decision and Order dated October 9, 2014 (the "**Decision and Order**"), which is the subject of this appeal;

2. Upon return of the appeal, if necessary, an Order that new evidence contained in the affidavit of Brian Lippold, filed, be admitted on the appeal as newly discovered evidence that is cogent, relevant to the outcome, and could not have been discovered prior to the Decision and Order; and

3. Such further and other relief as this Honourable Court may deem just.

THE GROUNDS FOR THE MOTION ARE:

1. NRG has discovered new evidence that was not available and could not have been previously placed in evidence in the hearing of this matter before the Board, nor been discovered by reasonable diligence up to the time the Board made its Decision and Order;

2. The new evidence is relevant and material to the issues in this matter, and is significant enough to potentially change the result set out in the Decision and Order;

3. NRG will be bringing a motion before the Board seeking leave and, if leave be granted, a review of the Decision and Order by the Board; and

4. Rule 3.02 of the *Rules of Civil Procedure*.

THE FOLLOWING DOCUMENTARY EVIDENCE will be used at the hearing of the motion:

1. The affidavit of Brian Lippold sworn December 8, 2014; and

2. Such further and other evidence as counsel may advise and this Honourable Court may permit.

Certificate of Counsel

Length of Oral Argument

Counsel estimates fifteen minutes will be required for the moving party's oral argument, not including reply.

____

John A. Campion

December 8, 2014

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Lawyers for Moving Party/Appellant,
Natural Resource Gas Ltd.

TO: **ONTARIO ENERGY BOARD**
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Board Secretary for Respondent, The Ontario Energy Board

AND TO: **TORYS LLP**
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Lawyers for the Respondent, Union Gas Limited

IN THE MATTER OF *the Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF a hearing of the Ontario Energy Board on its own motion in order to determine the Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations.

Court File No. 521/14

(Ontario Energy Board)
File No. EB-2014-0154

ONTARIO
SUPERIOR COURT OF JUSTICE
(DIVISIONAL COURT)

NOTICE OF MOTION

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Lawyers for the Moving Party/Appellant, Natural Resource Gas Limited

Exhibit “K”

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2014-0375

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations;

AND IN THE MATTER OF a Motion initiated by Natural Resource Gas Limited pursuant to the Ontario Energy Board's Rules of Practice and Procedure requesting that the Ontario Energy Board review its Decision and Order dated October 9, 2014 in its EB-2014-0154 proceeding.

Before: Cathy Spoel
Presiding Member

Marika Hare
Member

Ellen Fry
Member

This is Exhibit "K" referred to in the affidavit of Brian Lippold sworn before me, this 25th day of March 20 15

A COMMISSIONER FOR TAKING AFFIDAVITS

DECISION AND ORDER ON MOTION
March 13, 2015

BACKGROUND

Natural Resource Gas Limited (NRG) filed a notice of motion dated December 10, 2014 with the Ontario Energy Board (the OEB) under Rule 40.01 of the OEB's Rules of Practice and Procedure (the Rules) requesting that the OEB review and vary its Decision and Order dated October 9, 2014 in its EB-2014-0154 proceeding as it relates to the penalty charge applicable to NRG.

NRG specifically requested the following:

1) An order setting aside the timeframe under Section 40.03 of the Rules for filing a motion to review and vary;

2) An order varying the OEB's October 9, 2014 Decision and Order in EB-2014-0154 directing that NRG pay only Union's average cost of natural gas ($7.12 / GJ) for the 25,496 GJ of natural gas that NRG was short at the time of the Winter Checkpoint;

3) That the OEB combine its review of the Decision and Order in EB-2014-0154 with Phase 2 of the EB-2014-0053 proceeding (NRG's April 2014 QRAM) and the EB-2014-0361 proceeding (NRG's request for Interest Rate Relief / Stay); and

4) That the above noted issues all be heard by way of an oral hearing.

NRG relied upon Section 42.01 of the Rules for setting out the grounds for its motion to review and vary the EB-2014-0154 Decision and Order. Specifically, NRG sets the grounds for its motion as "new facts that have arisen" and "facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time." NRG, in its notice of motion, stated that it has discovered new evidence, facts and expert opinions that were not available and could not have been previously placed in evidence in the EB-2014-0154 proceeding, and could not have been discovered by reasonable diligence up to the time that the OEB rendered its Decision and Order on October 9, 2014.

In the Notice of Motion and Procedural Order No. 1 (the Notice), dated January 9, 2015, the OEB determined that, pursuant to Rule 43.01, it would hear submissions on the threshold issue of whether the motion should be heard on its merits. At the oral hearing the OEB heard argument from NRG, Union Gas Limited (Union) and OEB staff.

The following are the OEB's findings on the threshold question.

OEB FINDINGS

The motion is dismissed as the threshold test has not been met. However, as described in further detail below, the OEB will allow further evidence and submissions on a different issue on its own motion.

With respect to NRG's motion, NRG raised a number of facts that it believes were not available at the time of the EB-2014-0154 proceeding. NRG argued that these new facts could have impacted the OEB's decision had they been available at the time that the decision was rendered. Specifically, NRG characterized the facts outlined below as new evidence that could not have been placed on the record in the EB-2014-0154 proceeding:

NRG argued that it was unaware that Union itself was purchasing natural gas during the months of January and February 2014 at the same time that NRG was seeking to purchase natural gas. NRG argued that Union's own natural gas procurement activities impacted the price of natural gas in the market and impaired NRG's ability to meets its contractual obligations at a reasonable cost.

The OEB notes that the natural gas purchases made by Union over the 2014 winter were documented in Union's April 2014 Quarterly Rate Adjustment Mechanism (QRAM) application (EB-2014-0050). NRG was aware of Union's QRAM application, as it filed an intervention request in the proceeding. That application, and the information that it provided, was available to NRG in advance of the Decision and Order being issued in the EB-2014-0154 proceeding. The evidence in the QRAM proceeding indicated that it was necessary for Union, like many other market participants, to purchase incremental natural gas to meet the unusually high demands of its customers resulting from the weather conditions during the 2013-2014 winter. Accordingly, the OEB finds that this information cannot be characterized as a new fact. NRG ought to have been aware that Union was purchasing natural gas in the market during the 2014 winter and that this could have had an impact on the price of natural gas.

NRG also characterized a number of facts contained in the 2014 Natural Gas Market Review as new evidence.

NRG cited the fact that extreme winter weather conditions elevated natural gas demand through the U.S. and Ontario to record levels which led to a tight natural gas market and applied pressure on natural gas prices. NRG also referred to the fact that strong demand in the US Midwest impacted natural gas prices at Union's Dawn facility and caused higher than usual withdrawals from storage.

The OEB finds that this information was known by NRG at the time of the EB-2014-0154 proceeding. NRG in the EB-2014-0154 proceeding[1] accepted the fact that the 2014 winter was the coldest in Union's record for its Southern service area. It also referred to a Financial Times article that discussed the impact that the extreme cold weather conditions in the US had on the economy. This indicates that NRG was aware that the cold weather over the 2014 winter was a widespread phenomenon in the U.S. and Ontario.

The OEB considers that NRG ought to have been aware at that time that the sustained colder than normal weather (in both Canada and the US) would increase demand for natural gas and therefore apply upward pressure on natural gas prices, including at Union's Dawn facility. The OEB also considers that NRG should have been able to make the inference that increased demand for natural gas, both in Ontario and the US, would result in increased storage withdrawals (which would necessitate spot purchases later in the season as the weather continued to be colder than normal).

NRG also characterized as new evidence the fact that Union's checkpoint balancing requirements (for its direct purchase customers) coincided with ongoing strong demand in the market, which further exacerbated natural gas prices. The OEB considers that NRG must have been aware that there was significant demand for natural gas at the time of the winter checkpoint as NRG itself, as a direct purchase customer of Union, went to market to purchase natural gas immediately prior to the winter checkpoint and was unable to secure sufficient quantities to meet its own contractual obligations.

NRG also characterized as new evidence the fact that increased interruptible transport tolls, over the 2014 winter, limited the competitiveness of securing natural gas supply at Empress in Alberta. The OEB considers that this is evidence that could have been available to NRG at the time of the EB-2014-0154 proceeding. The OEB notes that TransCanada PipeLines' (TCPL) discretion to set its own interruptible tolls during the 2014 winter was approved by the National Energy Board (NEB) in a March 2013 decision.[2] Given the knowledge that TCPL had pricing discretion on its interruptible transportation services coupled with the fact that there was significant demand for natural gas over the 2014 winter, NRG ought to have been able to infer that TCPL was likely using its pricing discretion (and increasing its tolls in a tight gas market), which would apply pressure on natural gas prices at Dawn (as there were more limited economic supply options).

[1] Natural Resource Gas Limited, Submission, September 12, 2014, EB-2014-0154 at paragraphs 30 and 31.
[2] National Energy Board, Decision with Reasons, March 2013, RH-003-2011.

NRG also characterized some opinions expressed in the 2014 Natural Gas Market Review regarding gas supply planning as new evidence. These opinions are largely in relation to what natural gas prices may have been had the parameters underpinning the OEB-approved natural gas supply plans of the Ontario distributors been different (i.e. more base storage, increased firm transportation, and / or more conservative use of storage withdrawals). The OEB considers that the natural gas supply-related opinions cited are not relevant to this proceeding as they pertain to the implications of hypothetical gas supply planning parameters that were not in place over the 2014 winter.

The OEB agrees with Union and OEB staff that the information in the 2014 Natural Gas Market Review that NRG has characterized as new evidence is information that NRG either was, or ought to have been, aware of at the time that the EB-2014-0154 application was being heard, or is information that is not relevant to this proceeding.

For all of the above reasons, the OEB dismisses the motion at the threshold stage.

However, the OEB does have some concerns with the narrow question of whether the implications of NRG's status as a natural gas distributor regulated by the OEB was thoroughly addressed in the EB-2014-0154 proceeding. This issue was not submitted by NRG as grounds for the motion. However, the OEB will hear this issue on its own motion. The Board will combine this review with Phase 2 of NRG's QRAM proceeding (EB-2014-0053). Further procedural direction will follow.

COST AWARDS

The OEB may grant cost awards to eligible parties pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the OEB will apply the principles set out in section 5 of the OEB's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the OEB's Cost Awards Tariff will also be applied. Filings related to cost awards shall be made in accordance with the schedule set out below.

THE OEB ORDERS THAT:

1. The Motion is dismissed.

2. Eligible intervenors shall file with the OEB and forward to NRG their respective cost claims within 14 days of the date of this Decision and Order.

3. NRG shall file with the OEB and forward to the intervenors any objections to the claimed costs of the intervenors within 21 days from the date of this Decision and Order.

4. If NRG objects to the intervenor costs, intervenors shall file with the OEB and forward to NRG any responses to any objections for cost claims within 28 days of the date of this Decision and Order.

5. NRG shall pay the OEB's costs of, and incidental to, this proceeding immediately upon receipt of the OEB's invoice.

All filings to the OEB must quote file number **EB-2014-0375**, be made electronically through the OEB's web portal at www.pes.ontarioenergyboard.ca/eservice in searchable / unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address.

All filings shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available, parties may email their documents to the address below.

For all electronic correspondence and materials related to this proceeding, parties must include in their distribution lists the Case Manager, Lawrie Gluck at Lawrie.Gluck@ontarioenergyboard.ca and Senior Legal Counsel, Michael Millar at Michael.Millar@ontarioenergyboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

Filings: https://www.pes.ontarioenergyboard.ca/eservice/
E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

ISSUED at Toronto, March 13, 2015

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

EB-2014-0053
EB-2014-0361
EB-2015-0044

IN THE MATTER OF *the Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board* Act, 1998, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas as of April 1, 2014;

AND IN THE MATTER OF the Quarterly Rate Adjustment Mechanism;

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, for an order or orders granting rate relief and/or a stay from the imposition of interest on any amounts due for payment to Union Gas Limited related to the application of certain penalty charges;

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving a one-time exemption from Union Gas Limited's approved rate schedules to reduce certain penalty charges applied to direct purchase customers who did not meet their contractual obligations;

AND IN THE MATTER OF a hearing on the Board's own motion.

ONTARIO ENERGY BOARD

AFFIDAVIT of BRIAN LIPPOLD

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