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December 10, 2014

Ms. Doreen Friis
Regulatory Affairs Officer / Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, Nova Scotia B3J 3S3

Dear Ms. Friis:

RE: Heritage Gas Limited – Natural Gas Storage Service Costs Application

Please find enclosed:

(1) both a redacted and confidential copy of Heritage Gas Limited's ("Heritage Gas") Application with attachments ("Application") for Nova Scotia Utility and Review Board ("Board") approval of the cost treatment and recovery of natural gas storage service costs; and

(2) a draft of the form of public notice with respect to the Application ("Notice").

As natural gas storage service is new to Nova Scotia Heritage Gas proposes to hold a Technical Conference early in the new year to describe and respond to questions on the Application with the goal of better informing parties. At the Technical Conference Heritage Gas will also canvas the use of a written proceeding to deal with this Application.

By virtue of the nature of the Application certain confidential information is required to be filed for the Board and interested parties to be able to properly review the Application. Heritage Gas is cognizant of the need to ensure a transparent public review process for the Application and as such has made limited redactions to the Application. The redacted information is of two types: (1) information that relates to negotiations, procurement strategies or evaluation of gas supply options by Heritage Gas, and (2) specific commercial terms for the provision of natural gas storage services to Heritage Gas including a negotiated Precedent Agreement for gas storage services.

With respect to the former information, the public release of this information would provide potential counterparties of Heritage Gas with information that could assist them in their dealings with Heritage Gas to the detriment of Heritage Gas and its customers. With respect to the latter information, Heritage Gas' counterparty for the provision of natural gas storage services intends to carry on the merchant provision of natural gas storage service at its Nova Scotia facility, and the disclosure of the terms of the Heritage Gas arrangement would provide other potential users of the facility with inherently confidential information which could be used to their benefit and to the detriment of the owner of the facility. The public release of information of this type would not only put the owner of the facility in a competitively disadvantageous position but could also negatively impact further dealings by Heritage Gas on behalf of its customers if potential counterparties felt inherently confidential information of this nature was subject to full public disclosure.

Confidential information will be available to those parties who intervene in accordance with the Board's regular process in this regard and upon signing of the applicable confidentiality undertaking.

Heritage Gas requests that the Board provide it with: (1) directions on publication of the Notice, with further particulars of the process to be followed for review of the Application to occur after the proposed Technical Conference; and (2) such further directions, if any, as the Board determines appropriate at this time.

Please feel free to contact the undersigned if you have any questions.

Yours truly,

HERITAGE GAS LIMITED

Chris Smith
Vice-President, Business Development

cc: Phil Payzant – NSUARB
Bill Swan – Heritage Gas
Michael Johnston – Heritage Gas
David MacDougall – McInnes Cooper
John MacPherson – McInnes Cooper

Natural Gas Storage Service Costs Application

December 10, 2014

1 BACKGROUND & OVERVIEW

On September 4, 2013, the Nova Scotia Utility and Review Board ("NSUARB" or "Board") issued its Decision (NSUARB Matter No. M04172) granting Alton Natural Gas Storage LP ("Alton") approval to construct an underground hydrocarbon storage facility ("Alton Facility"). The Decision stated:

> *"NOW THEREFORE, the Board grants to Alton approval to construct the proposed works, subject to … terms and conditions"*

On November 6, 2013, Heritage Gas Limited ("Heritage Gas") filed an Application with the Board to determine whether the prudently incurred costs of natural gas storage should be included within Heritage Gas' cost of service (NSUARB Matter No. M05989). Heritage Gas' Application (Section 6.0 – lines 16-20) stated:

> *"Heritage Gas respectfully requests Board determination as to whether the prudently incurred costs of natural gas storage should be included within Heritage Gas' cost of service. The precise mechanism by which those costs will be incorporated into Heritage Gas' rates has not yet been determined. When the amount of these costs and the precise mechanism by which they will be incorporated into Heritage Gas' rates are known, the Board will have the opportunity to fully review them in a separate proceeding, as the Board requires."*

On February 20, 2014, the Board issued Decision 2014 NSUARB 42 stating:

> *"The Board finds that the storage of natural gas is a related service under Section 22(1) of the Gas Distribution Act and the prudently incurred costs of natural gas storage may be included with Heritage's cost of service."*

Following the Board's Decision of February 20, 2014, Heritage Gas engaged two independent expert consultants (ICF International ("ICF") and Navigant Consulting Ltd. ("Navigant")[1]) and Heritage Gas negotiated a Precedent Agreement ("PA") with Alton (dated October 20, 2014).

[1] ICF and Navigant have not previously been engaged by Alton in any capacity.

Specifically, the consultants were engaged to:

- Conduct an independent study of the benefits of natural gas storage and to advise whether having access to natural gas storage, in Nova Scotia, is beneficial to Heritage Gas and its customers (ICF – Attachment 1 to this Application);
- Conduct sensitivity analysis of various scenarios and to advise on whether the negotiated contract is beneficial for Heritage Gas and its customers (ICF – Attachments 2 and 3 to this Application); and
- Conduct an independent study on the cost of service and cost allocation for the storage service and to propose an appropriate rate design for the recovery of natural gas storage service costs (Navigant – Attachment 4 to this Application).

Heritage Gas believes that the natural gas storage service provided by Alton is crucial to ensuring security of gas supply for its customers. The service will also provide benefits to Heritage Gas and its customers in the form of enhanced reliability and delivery of natural gas during the peak heating season as well as reduced natural gas price volatility. The savings to customers is estimated to average more than $17.0 million/year over the 20-year term of the storage service contract.

In this Application, Heritage Gas is respectfully requesting Board approval of:

a) the natural gas storage service costs contemplated within the Precedent Agreement between Heritage Gas and Alton to be recovered in Heritage Gas' distribution rates;
b) the rate base treatment of (i) the cushion gas required for the Alton Facility and (ii) the investment in natural gas in storage, during the 20-year term of the Precedent Agreement; and
c) the proposed methodology for recovery and allocation of the natural gas storage service costs including the rate base items between Heritage Gas' rate classes.

2 NATURAL GAS STORAGE REQUIREMENTS

2.1 SUPPLY STRATEGY

The goal of Heritage Gas' natural gas supply strategy is to ensure that Heritage Gas is able to meet its customers' increasing supply requirements. The objectives of this strategy include:

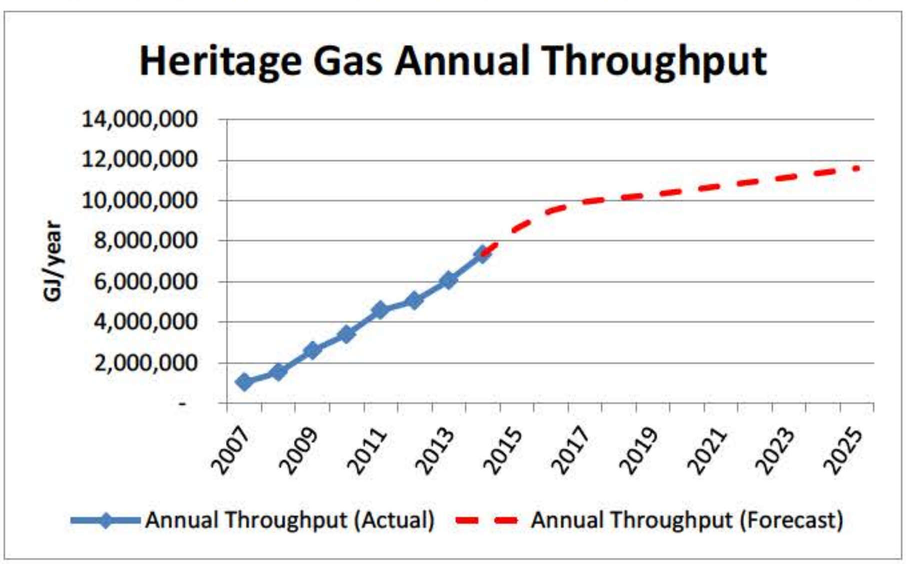
- Increasing the security of natural gas supply – particularly through diversity in suppliers and in the supply location; and
- Reducing price volatility – which has been inherent in the regional natural gas market due to a lack of upstream transportation, fluctuating Nova Scotia offshore production and lack of regional storage to meet winter demands.

Having access to a natural gas storage facility in Nova Scotia is fundamental to executing Heritage Gas' strategy and will provide benefits to its customers as described in the sections below.

2.2 DEMAND FORECAST

Heritage Gas has experienced continued growth since inception, requiring additional volumes of natural gas supply to meet the increasing demand. The growth in demand is expected to continue over the next few years and reach 10.1 million gigajoules ("GJ") by the end of 2017 when natural gas storage service is anticipated to be available at the Alton Facility. The forecasted demand growth beyond 2018 is approximately 2 percent per year.

Figure 1: Heritage Gas' annual delivered volumes, or throughput, since 2007 and forecast to 2025

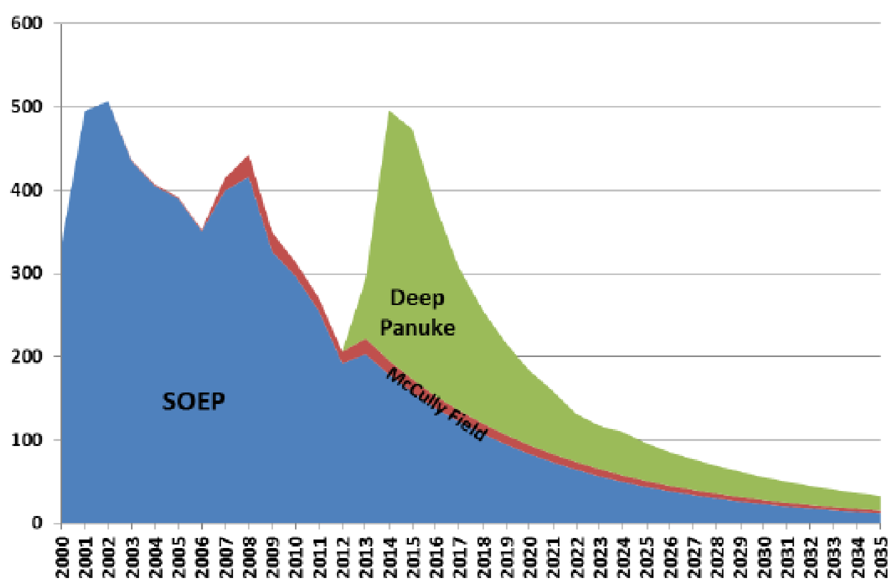


Similar to other Canadian natural gas distribution companies, Heritage Gas' highest demand periods are during the winter as natural gas is generally used for heating purposes. Natural gas storage enables companies to purchase natural gas in the summer months, when spot prices are generally cheaper, inject it into storage and withdraw it in order to meet the increased demand of the winter months, when spot prices are generally more expensive.

2.3 SUPPLY FORECAST

Historically Heritage Gas has predominately sourced its natural gas supply from offshore Nova Scotia through the Sable Island supply basin. There continues to be a decline in production from the Sable Offshore Energy Project ("SOEP") and there is an anticipated drop in production of the Deep Panuke project over the life-span of that project. The decline in production from both of these projects will affect the availability and deliverability of natural gas in the region over the next few years. This is illustrated in the figure below from an ICF report "The Future of Natural Gas Supply for Nova Scotia" prepared for the Nova Scotia Department of Energy, dated March 28, 2013.

Figure 2: Projected Maritimes Canada Gas Production in the ICF Base Case, Average MMcfd



Sources: National Energy Board Canada (Historical), ICF Base Case (Projection)

ICF's most recent analysis for Heritage Gas reaches the same conclusion that there will be a decrease in Nova Scotia production (Attachment 1, Section 1.1, page 1):

"Despite increased production from Deep Panuke, the forecast for domestic production is that it will decline over time and Nova Scotia must look to other markets for long term gas supply."

As production in the region declines over the next 10 years Heritage Gas must find solutions to address the supply requirements of its customers. In order to meet its customers' gas supply requirements Heritage Gas must have access to large volumes of natural gas that it can readily deliver. In the face of declining production from the Sable Island supply basin Heritage Gas will need to look at other supply basins for its gas supply requirements.

3 BENEFITS OF NATURAL GAS STORAGE

Heritage Gas' customers find themselves at the end of a tightly constrained supply of natural gas in the region making it difficult to source all of the natural gas required during peak eastern North American usage periods. While it is impossible to shift customers' peak demand from winter to summer, the supply side can be altered.

Natural gas storage helps to ensure security of natural gas supply while providing several benefits to Heritage Gas' customers. Those customers will have enhanced reliability of natural gas delivery during the peak-heating season as well as reduced natural gas price volatility and avoidance of the costs associated with contracting for additional long-haul pipeline transportation.

The benefits of natural gas storage are summarized within the May 31, 2013 ICF Report (filed with the Board in NSUARB Matter M05989), where ICF concluded (page ES-1):

> *"Heritage engaged ICF International (ICF) to provide an independent analysis of the Alton Project and to provide an estimate of its value from Heritage's standpoint. ICF evaluated the value of the proposed storage project based on a variety of alternative storage scenarios and supply portfolio options, as well as for a range of potential weather patterns. ICF's analysis indicates that Heritage Gas customers would benefit from the proposed storage. Our analysis also indicates that it is both a short-and long-term benefit. Based on the current forecast of gas prices, there would not be an identifiable period when storage costs exceed savings realized from storage. Storage can provide Heritage with supply security. Storage should provide Heritage with additional flexibility in future contracting.*
>
> *Based on our analysis, ICF concludes that for the Base Case natural gas market outlook, use of Alton Gas storage by Heritage Gas would significantly reduce the utility's expected supply portfolio cost, reducing costs to Heritage Gas consumers under all scenarios considered. This conclusion is robust across the full range of supply and storage scenarios considered. Based on our analysis, we would expect Heritage to see cost savings from the first year of storage service through the length of the storage contract. The basic conclusion that use of Alton storage capacity would reduce overall supply costs also holds even if Heritage Gas demand growth is*

slower or faster than projected, although the optimum amount of storage capacity would vary for alternative demand scenarios."

Given the passage of time since the completion of the 2013 study, Heritage Gas re-engaged ICF in 2014 to reassess the value of natural gas storage in Nova Scotia. ICF's most recent analysis (Attachment 1) confirmed storage would continue to provide multiple benefits to Heritage Gas and its customers under various hypothetical scenarios. The ICF Report's Executive Summary describes that benefits exist based on the updated market information, stating:

- *"Natural gas storage in Nova Scotia, as opposed to Ontario or other points farther upstream of Nova Scotia, would be beneficial to Heritage Gas and its customers both in the short term and in the long term."* (Attachment 1, page ES-1)
- *"Natural gas storage would provide Heritage Gas and its customers with increased security of supply. The value of this increased security is substantially higher than the cost of storage and is estimated to be between $10.00 per GJ and $21.90 per GJ based on current market estimates."* (Attachment 1, page ES-1)
- *"Buying gas storage in Ontario or any other upstream location and shipping gas to Nova Scotia would involve significantly higher costs than buying local storage from Alton. Ontario storage costs are lower than Alton; however the pipeline to bring the storage to the city gate would require buying capacity for Heritage's design day requirements, thus negating a major reason for acquiring storage in the first place."* (Attachment 1, page ES-2)

ICF's model was used to optimize natural gas commodity and storage capacity requirements on an annual basis, based on daily load requirements and daily natural gas prices over a range of potential weather conditions. The ICF analysis aims to determine the lowest overall portfolio cost, where costs include the commodity, pipeline and storage costs, and their modeling relies on perfect foresight considering weather and natural gas prices.

ICF's report concludes that storage provides benefits to Heritage Gas and its customers under a variety of scenarios (Attachment 1, Section 3.4, page 14):

*"**The basic conclusion that use of Alton storage as part of the Heritage Gas supply portfolio will reduce the total portfolio supply costs is robust across the full range***

__of supply and storage scenarios considered__. Based on our analysis, we would expect Heritage to see cost savings from the first year of storage service through the length of the storage contract." (__Emphasis Added__)

3.1 SENSITIVITY ANALYSIS

Following the conclusion of ICF's 2014 report (Attachment 1), Heritage Gas re-engaged ICF to examine whether the storage parameters in the negotiated PA with Alton would continue to generate benefits for Heritage Gas and its customers. ICF's analysis (Attachment 2) is based on the negotiated contractual terms between Heritage Gas and Alton. It shows that the [redacted] GJs of storage capacity, a maximum injection rate of [redacted] GJ/d, and a maximum withdrawal rate of [redacted] GJ/d produce significant benefits for Heritage Gas and its customers over the 20-year term compared to not contracting for storage. ICF's calculated savings for customers are estimated to average more than $17.0 million/year, based on various scenarios (Attachment 2, page 1):

Averages:	New England Supply w/[redacted] GJ Storage	New England Supply w/o Storage	Marcellus Supply w/[redacted] GJ Storage	Marcellus Supply w/o Storage	Mixed Supply w/[redacted] GJ Storage	Mixed Supply w/o Storage
2017/18 - 2021/22	$90,011,831	$105,560,476	$110,805,504	$137,899,315	$90,011,831	$105,560,476
2022/23 - 2026/27	$111,345,337	$128,111,014	$135,280,906	$162,463,730	$111,345,337	$128,060,228
2027/28 - 2031/32	$146,084,309	$164,442,971	$173,881,556	$200,544,383	$146,005,659	$163,887,001
2017/18 - 2034/35	$126,065,012	$143,584,681	$151,175,092	$178,135,032	$125,941,807	$142,993,530
Savings	$17,519,669		$26,959,940		$17,051,723	

As described by ICF (Attachment 2, page 2):

"In our opinion, the present Alton offer of storage as articulated above would reduce your gas purchase costs relative to not having storage and would provide substantial benefits to Heritage and your customers."

Heritage Gas also engaged ICF to evaluate the benefits of storage under a scenario where the New England natural gas historical seasonal price basis collapses (i.e. if the New England natural gas price spread between winter months and summer months were to diminish).

As described by ICF (Attachment 3):

"ICF ran two sets of cases. The first set of cases eliminates entirely the winter summer price spread and presents to the model a flat annual price for gas in all years. The second set of cases are based on a normal monthly price series for New England but without the daily volatility. This eliminates the daily winter price spikes seen in New England prices (as well as daily low price troughs at other times). Each month has relatively flat prices within the month, where the winter months have higher averages than summer months. This pattern comes out of the ICF Gas Market Model (GMM) forecast.

Exhibit A. Gas Supply Costs and Benefits of Storage at Flat and Moderated Seasonal Gas Prices in New England

	Storage Capped at [redacted]		No Storage	
Averages:	**New England Supply w/ Flat Annual Prices**	**New England Supply w/Monthly Average Prices**	**w/Flat Annual Prices**	**w/Monthly Average Prices**
2017/18 - 2021/22	$98,514,494	$95,430,135	$100,703,358	$108,197,280
2022/23 - 2026/27	$121,157,557	$118,828,256	$123,062,729	$131,863,454
2027/28 - 2031/32	$157,119,817	$156,128,376	$158,613,074	$168,979,538
2017/18 - 2034/35	$136,315,462	$134,454,880	$138,064,151	$147,456,197
Savings	$1,748,689	$13,001,316		

Exhibit A shows that at flat prices, the value of storage is still positive but considerably smaller than when prices follow normal seasonal patterns. The savings here arise from optimized pipeline capacity. Storage allows you to reduce pipeline capacity relative to the no storage option.

Taking out the volatility in gas prices but keeping the monthly average prices forecast in ICF's GMM still generates substantial benefits, as we would expect. Any further reduction in seasonality from the Monthly Average Price Scenario, would reduce savings, and the benefits would fall to somewhere between the Flat Annual Case and the Monthly Average Case."

ICF’s analysis demonstrates that even in the unlikely event of “flat annual prices” in the region, natural gas storage still provides benefit to Heritage Gas’ customers with savings of an estimated $1.7 million/year. Under this scenario, the value of storage would be based on supply security whereby Heritage Gas would have, in 2018, approximately [redacted] of its annual commodity requirements located less than 60 kilometers from its main market of the Halifax Regional Municipality.

Overall, storage will allow Heritage Gas to purchase natural gas during lower demand periods when gas prices are generally lower (i.e. summer), inject the natural gas into the storage facility, and then withdraw that natural gas during higher demand periods when gas prices are generally higher (i.e. winter). This will ensure that Heritage Gas has access to sufficient volumes of natural gas to meet its peak winter demand without resorting to the purchase of natural gas on the more expensive spot market or contract for additional long-haul pipeline transportation. Without storage, Heritage Gas would be required to buy pipeline capacity for the full design day requirement, as described within ICF’s Report, when assessing the estimated total cost to obtain similar natural gas storage services in Ontario (Attachment 1, page 20):

> *“… assuming that Heritage would acquire the same amount of storage as it would from Alton, total storage costs would be between* [redacted] *and about* [redacted] *per year, or about* [redacted] *to* [redacted] *per GJ for storage.* ***<u>Getting the gas to the city gate, however, will require Heritage to buy pipeline capacity for the full design day requirement, or about 72,000 GJ/d. Assuming a cost of</u>*** [redacted]***<u>, including fuel, the cost of transportation would add another</u>*** [redacted]***<u>,</u>*** *for a total storage delivery cost of between $78 million and $81 million per year, not including gas cost which is forecast to be higher at Dawn than in the Marcellus over the time period.*
>
> ***<u>The major problem with buying gas storage in Ontario and not in Nova Scotia is that it provides no opportunity to save on the costs of pipeline capacity, which a local storage service would provide. In addition it leaves Heritage’s full requirements susceptible to any disruption on a long pipeline route – a small risk we believe, still a risk.</u>****” (Emphasis Added)*

4 NATURAL GAS STORAGE SERVICE CONTRACT

Heritage Gas negotiated a PA with Alton for Firm Storage Service ("FSS"), which includes the following key parameters (Attachment 5):

- Term of Service – 20 years;
- Type of Service – Firm;
- Maximum Customer Inventory ("MCI") – [redacted]
  - Subject to availability after completion of project.
- Maximum Daily Injection Quantity – [redacted] GJ/day, which is equal to [redacted] multiplied by the MCI;
  - Subject to adjustment once the availability of project is determined.
- Maximum Daily Withdrawal Quantity – [redacted] GJ/day, which is equal to [redacted] multiplied by the MCI;
  - Subject to adjustment once the availability of project is determined.
- Cushion gas volume ("Cushion Gas") – [redacted] GJs, which represents 25% of the contracted capacity (i.e. MCI), which remains in facility at all times.
- Inventory Demand Rate ("IDR") – [redacted] (annual);
  - Subject to potential adjustment based on actual construction costs and an annual escalation of [redacted]
- Injection/Withdrawal Commodity Charge – [redacted]; and
  - Subject to an annual adjustment equal to the Consumer Price Index ("CPI") for Nova Scotia for the previous year.
- Excess Injection/Withdrawal Rate – [redacted] for volumes above the maximum injection or withdrawal quantity.

5 NATURAL GAS STORAGE SERVICE COSTS

Alton will be the owner / operator of the Alton Facility and is in the process of developing the salt caverns for the storage of natural gas. Heritage Gas will be a customer of Alton's and the costs Heritage Gas will incur include the following.

5.1 INVENTORY DEMAND RATE

The IDR is based on the Target Project Cost and Initial Project Target Capacity. IDR is [redacted] per GJ of MCI per month ("Target IDR"), subject to adjustment as follows:

- If Unitized Actual Construction Cost > Unitized Target Construction Cost:
  - IDR increase = Target IDR * ((A-T)/ T)
- If Unitized Actual Construction Cost < Unitized Target Construction Cost:
  - IDR reduction = Target IDR * ((A-T)/ T)

Where:
A = Unitized Actual Construction Cost, which equals actual construction cost divided by the lesser of (i) Actual Capacity or (ii) Initial Project Target Capacity.

T = Unitized Target Construction Cost, which equals Target Construction Cost divided by Initial Project Target Capacity.

The IDR is subject to annual escalation of [redacted].

5.2 INJECTION COMMODITY RATE

An Injection Commodity Rate ("ICR") of [redacted] per GJ will be charged to Heritage Gas based upon the quantity of natural gas delivered to the Alton Facility by or on behalf of Heritage Gas.

The ICR is subject to annual adjustment equal to the CPI (All-Items, Nova Scotia) change over the previous contract year.

5.3 WITHDRAWAL COMMODITY RATE

A Withdrawal Commodity Rate ("WCR") of [redacted] per GJ will be charged to Heritage Gas based upon the quantity of natural gas withdrawn by or on behalf of Heritage Gas from the Alton Facility.

The WCR is subject to annual adjustment equal to the CPI (All-Items, Nova Scotia) change over the previous contract year.

5.4 CUSTOMER'S FUEL GAS QUANTITY

2% of the volume of gas delivered by Heritage Gas to the Alton Facility in a gas year associated with fuel gas used for compressors at the Storage Facility.

5.5 CUSHION GAS

Cushion Gas is required in order to make the Alton Facility operational. The Cushion Gas will be purchased and injected into the Alton Facility by Heritage Gas representing 25% of the estimated MCI for Heritage Gas. Therefore, the carrying value of the Cushion Gas will become part of Heritage Gas' rate base.

5.6 NATURAL GAS IN STORAGE

Natural gas in the Storage Facility ("Natural Gas in Storage") will provide Heritage Gas a mechanism to recover the average carrying cost of the natural gas in storage inventory (i.e. cost of capital and related tax costs on Natural Gas in Storage and Cushion Gas).

5.7 GENERAL

Any other fees, charges and other amounts payable in accordance with the PA between Alton and Heritage Gas, including associated taxes and insurance costs.

6 NATURAL GAS STORAGE RATES

The following sections describe the proposed mechanism by which the natural gas storage service costs will be recovered and incorporated into Heritage Gas' rates.

6.1 NAVIGANT REPORT OVERVIEW

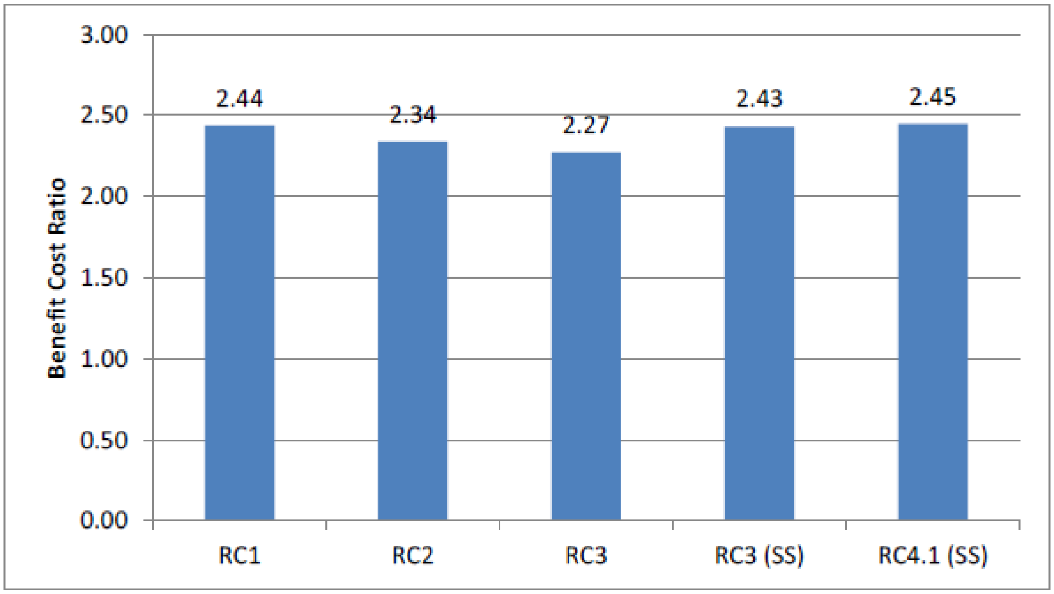
Navigant was retained by Heritage Gas to develop a proposed cost allocation and rate design for the recovery of costs incurred related to the natural gas storage service. Navigant's findings are primarily indicative as much of the detailed information required to calculate cost of service and to develop rates to recover these costs cannot yet be known with certainty. The number of customers as well as the actual construction costs for the Alton Facility will change key variables in the cost of service (total throughput, throughput by rate class, total demand, IDR, etc.). Further, Heritage Gas expects Rate Class 1 customers to make up a greater proportion of future customer additions than in the past. This will result in changes to the seasonality of cost of service variables (i.e. throughput, demand).

Navigant's recommendations are based on expected cost of service assuming maximum utilization of the Alton Facility and using recent historical data (June 2012 – May 2014). Recent historical consumption and demand are viewed by Heritage Gas as a conservative case as customer growth between now and 2018[2] will serve to lower the per GJ cost to customers.

Heritage Gas believes that in addition to ensuring that storage provides value to its entire customer base, it is vital that storage provide value to each of its customer classes. The indicative results of the Navigant report provide strong evidence that each of Heritage Gas' customer classes will benefit from the storage services. Navigant's report outlines the benefit-cost ratio for each rate class (Section 6.2, page 13):

[2] 2018 is the anticipated commencement of natural gas storage services.

Figure 3 –Benefit Cost Ratio for the Seasonal Volumetric Approach



> *"Figure 3 above illustrates that the storage field will, on average, yield a benefit-cost ratio of approximately 2.37 given market prices for the year 2013. Each tariff class is receiving something very close to the average benefit-cost ratio …"*

6.2 DETERMINATION OF FUNCTIONAL COST OF SERVICE

Section 4 of the Navigant report estimates the cost of service / revenue requirement of the Alton natural gas storage service based on full utilization of the capacity available to Heritage Gas.

Navigant proposes that these costs should be functionalized as follows (Section 4, page 7):

> *"The indicative revenue requirement separates the cost of storage into three distinct functions. The first function captures all charges associated with the Alton Facility contract. The second function includes the costs associated with the Cushion Gas. The third function includes the costs associated with the Natural Gas in Storage."*

6.2.1 ALTON FACILITY STORAGE FIELD CHARGES

Table 2 of the Navigant report details the estimated costs directly associated with the PA contract between Heritage Gas and Alton. Table 2 is reproduced below (Section 4.1, page 8):

Table 2 – Summary of Revenue Requirement for the Alton Facility Contract Charges

Component	Amount
Inventory Demand Charges[3]	[redacted]
Expenses Associated With Injections	
Expenses Associated With Withdrawals[4]	
Total Revenue Requirement for Alton Facility	

Source: Appendix B

6.2.2 COST OF CUSHION GAS

As the actual cost cannot be known prior to the actual purchase and injection of the Cushion Gas, Navigant estimated the investment in Cushion Gas based on historical natural gas market price data[3] for the period of May 1 through September 30, 2013. Heritage Gas believes this is a reasonable manner by which to estimate this investment. The revenue requirement associated with the investment in Cushion Gas is determined by applying Heritage Gas' approved Weighted Average Cost of Capital ("WACC") to the investment in Cushion Gas. Navigant estimates the total investment in Cushion Gas to be $4.25 million (Section 4.2, page 8). Navigant estimates the total annual carrying cost of the Cushion Gas (including the recovery of income taxes related to the equity return) to be [redacted] million (Appendix B of the Navigant Report).

6.2.3 COST OF NATURAL GAS IN STORAGE

Similar to Cushion Gas, the actual cost of Natural Gas in Storage cannot be determined prior to actual investment. Unlike Cushion Gas, which is injected a single time as part of the preparation of the Storage Facility, Natural Gas in Storage will be injected into and withdrawn from the facility annually. While the cost of the Natural Gas in Storage itself will not constitute a cost of service for the storage service, the carrying costs associated with this gas will. Navigant has estimated these costs based on the same historical pricing as the Cushion Gas and has estimated that on average 50% of the total capacity would be carried throughout the year. Navigant further recognized that a portion (estimated to be approximately 13%) of the Natural Gas in Storage would be held on behalf of self supply customers and that there would be no carrying costs associated with this portion of the gas. The revenue requirement associated with the remaining (average) investment in Natural Gas in Storage is then determined by applying Heritage Gas' approved WACC. Navigant estimates the total annual carrying cost of the Natural Gas in Storage (including the recovery of income taxes) to be [redacted] million (Appendix B of the Navigant Report).

[3] Data for Algonquin Citygate delivery point based on SNL Spot Natural Gas Index.

6.2.4 TOTAL INDICATIVE COST OF SERVICE

Navigant estimates the total annual cost of storage to be $14.0 million. Navigant states (Section 4.5, page 9):

> *"Based upon the above assumptions Navigant has prepared the following first year indicative revenue requirement associated with the Alton Facility, Cushion Gas and Natural Gas in Storage summarized in Table 4 below."*

Table 4 – Indicative Revenue Requirement for the Alton Facility Cushion Gas and Natural Gas in Storage

Component	Amount
Total Rev. Req. for Alton Storage Facility	[redacted]
Total Rev. Req. for Cushion Gas	[redacted]
Total Rev. Req. for Natural Gas in Storage	[redacted]
Total Revenue Requirement	$14,041,509

Source: Appendix C

Appendix B of the Navigant report details all of the calculations for each of the costs described above.

6.3 CLASSIFICATION OF COSTS

Section 5 of the Navigant report describes the recommended approach to classification of costs.

> *"Navigant recommends the adoption of the Equitable Method of classifying costs of the Alton Facility, the associated Cushion Gas and the carrying costs of natural gas. Navigant recommends that this method be used as this method is used in the natural gas industry and detailed in the U.S. FERC Natural Gas Pipeline Manual[4]. The Equitable Methodology uses the following process to classify costs:*
>
> *(1) Fifty percent of the fixed cost of storage is classified as Deliverability. The "Deliverability" function of a storage field refers to the ability of the storage field to withdraw gas on a particular day. (FERC page 58)*
>
> *(2) Fifty percent of the fixed cost of storage is classified as Capacity. The "Capacity" function refers to the storage field's capacity to store gas for a designated customer or for system operations. (FERC page 58)*

[4] Federal Energy Regulatory Commission Cost of Service Manual, June, 1999, p. 58.

(3) All variable costs are classified as Injection/Withdrawal. The Injection/Withdrawal component refers to the storage fields function with injecting and withdrawing gas for customers or for system operations.

Navigant classified the total indicative cost of service in Table 5 of their report (Section 5.1, page 10):

Table 5 – Proposed Classification of the Storage Revenue Requirement

Alton Contract Pricing Component	Deliverability	Capacity	Injection / Withdrawal
Injection / Withdrawal Commodity			100%
Inventory Demand Charge	50%	50%	
Natural Gas in Storage/Cushion Gas	50%	50%	

Heritage Gas agrees with Navigant that the Equitable Method is an appropriate method for the classification of the natural gas storage service costs.

6.4 ALLOCATION OF COSTS

Section 6 of the Navigant report outlines the approach to the allocation of costs. As described in Navigant's report (page 13):

"Navigant proposes a seasonal volumetric approach for the allocation of costs to specific tariff classes. Navigant believes the seasonal volumetric approach provides a cost-justified and equitable approach to cost allocation affording benefits to all tariff classes.

6.1 Seasonal Volumetric Approach

The seasonal volumetric approach allocated storage field costs based upon usage incurred during the peak season (November to April). Navigant believes the seasonal volumetric approach is reasonable because costs are allocated based upon usage during that time of year when storage is providing service to customers. Therefore, customers using the Heritage system during summer months when the storage system is providing limited value will not be allocated costs associated with the storage system. Note that the costs associated with Natural Gas in Storage (i.e. the costs of carrying an average inventory on natural gas in the Alton facility) were not *allocated to self supply tariff because the customers served under those tariffs would presumably provide their own natural gas to the Alton Facility."*

Table 7 – Allocation of Alton Storage Field Costs to Tariff Classes

Alton Facility Charges	System Supply			Self Supply		Total
	Rate 1	Rate 2	Rate 3	Rate 3	Rate 4.1	Total
Allocator %	33.24%	29.36%	24.77%	[redacted]		100.00%
Alton Storage Field Costs	[redacted]					
Cushion Gas Costs	[redacted]					
	[redacted]					
Allocator % (Natural Gas in Storage)	[redacted]					
Natural Gas in Storage	[redacted]					
Total Revenue Requirement						$14,041,509

Source: Appendix E

**Please note that "System Supply" refers to Heritage Gas arranging for gas supply on behalf of its customers and "Self Supply" refers to customers who are arranging for their own gas supply.*

Heritage Gas agrees with Navigant's recommendation to use the seasonal volumetric approach. Heritage Gas notes that while the use of a volumetric allocation for demand related costs (i.e. deliverability classification) may be counterintuitive, seasonal volumes by customer class serve as a proxy for demand by customer class. Heritage Gas believes that seasonal energy use is strongly correlated with peak demand for each of its customer classes. However, actual demand for Heritage Gas small volume customers is not measured.

6.5 PROPOSED PRICING DESIGN

Section 7 of the Navigant report proposes the use of a volumetric charge on all natural gas delivered during the withdrawal season (November to April). The rates presented below are based on historical demand and consumption by rate class and are meant to be indicative only, as the costs cannot yet be known with certainty until after construction is completed. The indicative rates are detailed in Table 9 of the Navigant Report (Section 7.1, page 15):

Table 9 – Proposed Storage Pricing Design for the Alton Facility

Components of Storage Charge	System Supply Charges ($/GJ)	Self Supply Charges ($/GJ)
Alton Facilities Charge ($/GJ)	$2.50131	$2.50131
Cushion Gas ($/GJ)	$0.09304	$0.09304
Natural Gas in Storage ($/GJ)	$0.18607	
Total	$2.78042	$2.59435

Source: Appendix E

Heritage Gas agrees with Navigant's proposal that a seasonal volumetric charge is the appropriate method for recovering the costs of storage. The benefits of storage will predominantly be gained in the withdrawal season and therefore costs should be charged during this period. Further, the commodity cost savings from the use of storage are predominantly volumetric (i.e. lower cost per GJ) so recovery of storage related costs on this basis is appropriate. The commodity cost savings more than offset these additional charges as demonstrated in the ICF Study including on a customer class basis (see Cost Benefit Analysis – Section 6.6 of this Application below).

The figures in Table 9 are provided for illustrative purposes. As described above and throughout the Navigant Report, the rates are only meant to be indicative. In this Application, Heritage Gas is requesting approval of the methodology for cost allocation and rate design, not approval of specific rates. Assuming Target Project Cost and Initial Project Target Capacity for the Alton Facility are achieved, Heritage Gas believes the indicative rates described above to be conservative. Higher seasonal volumes forecast for the winter of 2018 would result in lower storage charges on a $/GJ basis. For example, by using Heritage Gas' forecasted 2018 consumption (consistent with the ICF study) rather than recent historical consumption (as used in the Navigant Report) and keeping all other variables the same as included in the Navigant Report, the resulting rates are estimated to be as follows:

Components of Storage Charge	System Supply Charges ($/GJ)	Self Supply Charges ($/GJ)
Alton Facilities Charge ($/GJ)	$1.82499	$1.82499
Cushion Gas ($/GJ)	$0.06788	$0.06788
Natural Gas in Storage ($/GJ)	$0.13576	
Total	$2.02863	$1.89287

6.6 BENEFIT-COST ANALYSIS

Heritage Gas believes each customer class will achieve a net benefit from the use of storage in addition to improvements to security of supply. Navigant estimated the potential savings storage would offer each rate class and compared these to the costs allocated to them by the Seasonal Volumetric Approach. Navigant states (Section 6.2, pages 12-13):

> *"Navigant prepared an analysis comparing the cost allocation produced by the seasonal volumetric approach discussed above to the benefits which customers are predicted to experience from the storage field. Navigant believes that any cost allocation approach which would provide a tariff group with a cost allocation greater than the benefits a group is expected to receive could be construed as not equitable even if strict cost allocation standards are met.*
>
> *Navigant used data for the year 2013 and applied a simple algorithm to estimate the savings which are derived from the proposed Alton Facility if the storage facility were in place in 2013. The algorithm assumed that the storage field would receive injections during the lowest cost days and would experience withdrawals during the high cost days. Natural gas prices were based upon observed spot price values at Algonquin City-Gates. Navigant's analysis quantified a net benefit value of $33,237,202 for the storage field in 2013.*
>
> *The next step in the analysis estimated the specific monthly value of the storage field for each month. Different tariff classes have varying levels of monthly usage. Navigant expects that customers using more natural gas during the winter would receive a greater benefit than customers with a more levelized natural gas consumption pattern because the storage field will generally provide the greatest utility during peak usage months.*
>
> *The results of the comparison of the cost allocation to customer benefits are provided in Figure 3 below.*

Figure 3 –Benefit Cost Ratio for the Seasonal Volumetric Approach

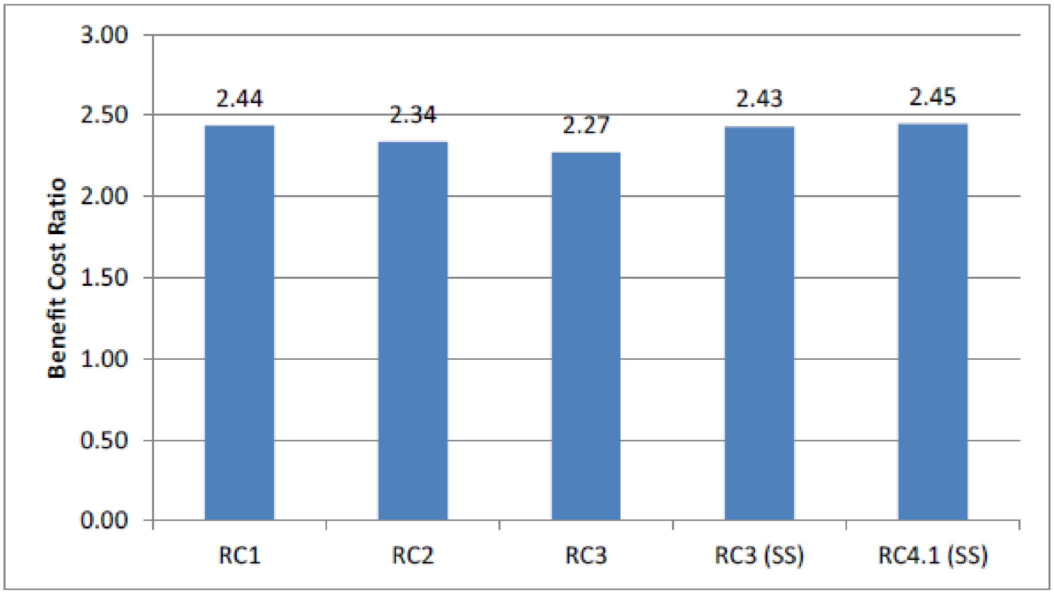


Figure 3 above illustrates that the storage field will, on average, yield a benefit-cost ratio of approximately 2.37 given market prices for the year 2013. Each tariff class is receiving something very close to the average benefit-cost ratio with Rate Class 3 receiving a ratio of 2.27 benefits to costs as the lowest benefit cost ratio and RC4.1 self supply receiving a ratio of 2.45 benefits to costs as the maximum. These values are calculated based upon the revenue requirement allocated to each rate class (or the "cost") and the estimated cost for use of the storage facility for each rate class (or the "benefit"). This "benefit" is defined by an algorithm that assumed that the storage field would receive injections during the lowest cost days and would experience withdrawals during the high cost days."

Navigant's determination of a net benefit of $33 million is based on actual 2013 natural gas price volatility. It therefore differs from the estimates provided by ICF which are based on a variety of more conservative and less volatile natural gas pricing scenarios (please refer to Attachment 1, Page 4, Exhibit 2-3 for the ICF historical pricing and forecast for alternative market centers).

6.7 RECONCILIATION OF THE ALTON FACILITY CONTRACT CHARGES

Section 8 of the Navigant report describes the need for and recommends the use of a Reconciling Clause Mechanism to ensure that Alton Facility contract costs are not over- or under-recovered. The Reconciling Clause Mechanism which Heritage Gas concurs with would be used to automatically adjust the storage rates charged to customers for variances in the previous storage year. Heritage Gas anticipates that these variances would be primarily the result of variances in total volumes during the November to April period (volumes over which to recover the costs) but could also result from higher or lower injections or withdrawals (including any excess injection or excess withdrawal charges) or from higher or lower cost of fuel gas.

Heritage Gas recognizes that potential over- or under-recoveries related to other storage costs (specifically Cushion Gas Costs and Natural Gas in Storage) are possible. Heritage Gas considers that it is appropriate to provide protection to Heritage Gas and customers from these over- and under-recoveries as well, either through the same reconciling mechanism or through a similar, separate mechanism. Heritage Gas anticipates that these variances would result from higher or lower total volumes during the November to April period as well as from higher or lower average cost of natural gas in storage (carrying costs).

6.8 PROPOSED BILL EXAMPLE INCLUDING STORAGE SERVICE COSTS

Heritage Gas proposes that the costs associated with the storage service would be included on customers' bills as a separate line item, as shown in Attachment 6.

7 INTER-AFFILIATE CODE OF CONDUCT CONSIDERATIONS

Heritage Gas and Alton are affiliates, as both companies are wholly-owned entities of AltaGas Ltd. ("AltaGas"). The Heritage Gas Inter-Affiliate Code of Conduct ("Code")[5] governs the standards and parameters for any transactions between affiliates. As described in Section 1.1 of the Code:

> *"The purpose of the Inter-Affiliate Code of Conduct is to set out the standards and conditions for the interaction between Heritage Gas Limited ("Heritage Gas") and its affiliated companies. The principal objectives of the Code are to enhance a competitive market while, at a minimum, keeping ratepayers unharmed by the actions of Heritage Gas with respect to dealing with its affiliates."*

The PA for natural gas storage services executed between Alton and Heritage Gas was completed with due diligence and in compliance with the Code.

It is Heritage Gas' understanding that the Alton Facility will be operated as a "for profit" project. Section 2.1 (k) of the Code defines "For Profit Affiliate Service":

> *"(k) "For Profit Affiliate Service" means any service, provided on a for-profit basis:*
>
> *i. by Heritage Gas to an Affiliate, other than a Regulated Service; or*
>
> *ii. ii. by an Affiliate to Heritage Gas."*

Section 4 of the Code outlines the requirements of Heritage Gas to determine the prudency of "For Profit Affiliate Services" arrangements. As described in section 4.2:

> *"When Heritage Gas acquires For Profit Affiliate Services, it shall pay no more than the Fair Market Value of such services."*

Section 2.1 (j) of the Code defines Fair Market Value as:

> *"(j) "Fair Market Value" means the price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act."*

Section 4.5 describes the method for determining Fair Market Value ("FMV"):

[5] The Inter-Affiliate Code of Conduct was approved by the Board on October 11, 2012 (NSUARB Matter No. M04847).

> *"In demonstrating that Fair Market Value was paid or received pursuant to a For Profit Affiliate Service arrangement or a transaction … Heritage Gas … may utilize any method to determine Fair Market Value that it believes appropriate in the circumstances. These methods may include, without limitation: competitive tendering, competitive quotes, bench-marking studies, catalogue pricing, replacement cost comparisons or recent market transactions. Heritage Gas shall bear the onus of demonstrating that the methodology or methodologies utilized in determining the Fair Market Value of the subject goods or services was appropriate in the circumstances."*

Competitive tendering, competitive quotes, bench-marking studies, catalogue pricing, replacement cost comparisons or recent market transactions are not particularly relevant methods to determine FMV in this context. As described in this Application, the Alton Facility will be the only natural gas storage facility in the Maritimes, as there are no other underground gas storage facilities north of Boston, Massachusetts along the Maritimes & Northeast Pipeline ("M&NP") route. However, in order to compare reasonable alternatives, Heritage Gas requested that ICF evaluate reasonable replacement cost comparison alternatives. Heritage Gas requested that ICF investigate:

- the total cost of obtaining storage in Ontario (or another facility within close proximity); and
- the total cost to utilize the LNG facility at Canaport as an alternative to the Alton Facility.

ICF concluded that these alternatives are either not competitive or available. As described in the ICF Report, ICF states (Attachment 1, page ES-2):

- *"7. Buying gas storage in Ontario or any other upstream location and shipping gas to Nova Scotia would involve significantly higher costs than buying local storage from Alton. Ontario storage costs are lower than Alton; however the pipeline to bring the storage to the city gate would require buying capacity for Heritage's design day requirements, thus negating a major reason for acquiring storage in the first place. ICF estimates that total fixed costs for Ontario storage and pipeline transportation from Ontario to Nova Scotia, without gas, would range between $78 million and $81 million per year, of which pipeline transport would account for* [redacted]*."*

- *"8. ICF does not believe Canaport offers an alternative to Alton storage. First we are not aware if Canaport has offered a storage service and do not believe Canaport has the liquefaction facilities to provide storage service. Our estimate of the cost of gas from Canaport were it to provide a LNG peaking service or seasonal service would be approximately $13.39 per GJ based on current forward prices for gas from LNG in the U.K., which would be the opportunity cost of gas for Canaport. This would be a higher cost than Alton and would not necessarily provide a seasonal storage service, but a shorter term peaking supply."*

Heritage Gas therefore considers that the natural gas storage services contract between Alton and Heritage Gas represents a prudently incurred cost for the services being provided, which complies with the Inter-Affiliate Code of Conduct.

All transactions between Heritage Gas and Alton will be identified in the "Affiliated Party Transaction Summary", included within Heritage Gas' Inter-Affiliate Code of Conduct Annual Compliance Report, which is filed with the Board on an annual basis.

8 SUMMARY

Heritage Gas believes the natural gas storage service provided by Alton is crucial to ensuring security of supply in the region and provides benefits to Heritage Gas and its customers in the form of enhanced reliability and delivery during the peak heating season as well as reduced natural gas price volatility.

Heritage Gas respectfully requests Board approval of:

a) the natural gas storage service costs contemplated within the Precedent Agreement between Heritage Gas and Alton to be recovered in Heritage Gas' distribution rates;
b) the rate base treatment of (i) the cushion gas required for the Alton Facility and (ii) the investment in natural gas in storage, during the 20-year term of the Precedent Agreement; and
c) the proposed methodology for recovery and allocation of the natural gas storage service costs including the rate base items between Heritage Gas' rate classes.

9 ATTACHMENTS

In support of this Application, Heritage Gas attaches the following:

- Attachment 1 — ICF Report: "Updated Assessment of Alton Natural Gas Storage" (Dated July 18, 2014)
- Attachment 2 — ICF Sensitivity Analysis: "Opinion Regarding Alton Storage Offer" (Dated September 9, 2014)
- Attachment 3 — ICF Sensitivity Analysis: "Reduced Seasonal Gas Price Spreads" (Dated September 18, 2014)
- Attachment 4 — Navigant: Cost-of-Service and Pricing Recommendations for the Alton Natural Gas Storage Field Service Costs (Dated December 4, 2014)
- Attachment 5 — Precedent Agreement between Heritage Gas and Alton (Dated October 20, 2014)
- Attachment 6 — Proposed Heritage Gas Bill Including Storage Costs

Attachment 1.
ICF Report: "Updated Assessment of Alton Natural Gas Storage"
(Dated July 18, 2014)

Updated Assessment of Alton Natural Gas Storage

July 18, 2014

Submitted to:

Heritage Gas

Submitted by:

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Table of Contents

Findings and Recommendations

In 2013 ICF International (ICF) prepared an analysis for Heritage Gas (Heritage) of a proposal from Alton Natural Gas Storage LP (Alton), to provide Heritage with gas storage services from its proposed Alton Storage Project. Heritage has requested ICF to update that analysis to reflect recent developments in gas markets, Heritage's updated gas demand forecast, and a revised proposal from Alton. For this study, ICF repeated the first analysis as if Heritage were buying gas priced at a New England index but we also examined the implications for storage if Heritage were to secure gas supply in the Marcellus or at Dawn, Ontario, and ship it to Nova Scotia.

Heritage is faced with making a decision on acquiring Alton storage in a time of significant uncertainty about gas markets in the Northeast. In our assessment, storage benefits Heritage and its customers under all of the cases we have examined. The further question of whether Heritage should contract for pipeline capacity to upstream supply sources in Marcellus is more difficult to answer. A central question is whether supply acquired in New England, at New England prices, can be considered as reliable as supply sourced in the production fields of the Marcellus Basin.

Any supplier of gas to Heritage in New England will have to source the gas in Marcellus or some other location, since New England has no indigenous production, and offer the gas to Heritage at the New England market price, as we have modeled it. That New England supplier will have had to contract for gas pipeline capacity to a supply source. The reliability of the resulting gas supply in New England, as well as the price, will depend on whether and how much new pipeline capacity is constructed into New England and connected to M&NP, among other things. Several new pipeline expansion projects have been proposed by Spectra, Kinder Morgan, and others. The reliability of New England supply will also depend on the quality of the counterparties providing the gas and the terms of the supply contracts underlying the supply, factors which are also relevant to Marcellus-based supply, but which may take on added importance with a New England-based supply contract.

In this engagement, Heritage asked ICF to address a number of key questions. Our findings are summarized below.

1. Natural gas storage in Nova Scotia, as opposed to Ontario or other points farther upstream of Nova Scotia, would be beneficial to Heritage Gas and its customers both in the short term and in the long term. This is demonstrated in the ICF analysis provided in section 3 below.

2. Natural gas storage would provide Heritage Gas and its customers with increased security of supply. The value of this increased security is substantially higher than the cost of storage and is estimated to be between \$10.00 per GJ and \$21.90 per GJ based on current market estimates. (See section 4, question b below.)

3. ICF recommends that Heritage Gas enter into a contract for gas storage service where the maximum customer inventory is between [redacted] and [redacted] based on the averages for the time periods analyzed, with an average of [redacted] over the period of the analysis, if securing supply in New England. We recommend that Heritage secure an additional [redacted] of storage capacity for weather security. (See sections 3.3.1 and 3.3.2).

4. A key driver of storage value is the rate of withdrawal or deliverability from storage. The daily withdrawal [redacted]

[redacted] (See section 3.3.3.)

5. ICF examined alternative sources of supply including New England, Marcellus, and Dawn and estimated the amount of pipeline capacity Heritage would acquire if buying in those locations. We dismissed Dawn as being the most expensive option because of the high pipeline costs, coupled with a gas price at the hub that was higher than Marcellus.

   For the New England Hub only: between [redacted] (for the 2017/18 – 2021/22 period) and [redacted] GJ/d (for the 2027/28 2031/32 period)
   For the Marcellus Hub only: [redacted] (for the 2017/18 – 2021/22 period) and [redacted] GJ/d (for the 2027/28 2031/32 period)

6. While the Marcellus offers lower gas prices and lower price volatility, the higher cost of pipeline transportation from there to Nova Scotia offsets any gas price advantage Marcellus has over New England. This observation does not take into account the level of gas supply security that having access to Marcellus may bring to Heritage. (See section 3.4.)

7. Buying gas storage in Ontario or any other upstream location and shipping gas to Nova Scotia would involve significantly higher costs than buying local storage from Alton. Ontario storage costs are lower than Alton; however the pipeline to bring the storage to the city gate would require buying capacity for Heritage's design day requirements, thus negating a major reason for acquiring storage in the first place. ICF estimates that total fixed costs for Ontario storage and pipeline transportation from Ontario to Nova Scotia, without gas, would range between $78 million and $81 million per year, of which pipeline transport would account for [redacted] (See section 4, question f.)

8. ICF does not believe Canaport offers an alternative to Alton storage. First we are not aware if Canaport has offered a storage service and do not believe Canaport has the liquefaction facilities to provide storage service. Our estimate of the cost of gas from Canaport were it to provide a LNG peaking service or seasonal service would be approximately $13.39 per GJ based on current forward prices for gas from LNG in the U.K., which would be the opportunity cost of gas for Canaport. This would be a higher cost than Alton and would not necessarily provide a seasonal storage service, but a shorter term peaking supply. (See section 4, question g.)

1 Introduction

1.1 Purpose of the Study

Heritage Gas (Heritage) has received a proposal from Alton Natural Gas Storage LP (Alton), to provide Heritage with storage services. At the same time Heritage is examining new gas supply and transportation options, namely securing future gas supply from various U.S. and Canadian locations and using expanded pipeline capacity through New York and New England to deliver gas into Nova Scotia. This alternative would have different gas supply and transportation costs that need to be considered in evaluating storage proposal from Alton. In the meantime, the gas supply situation in Nova Scotia continues to evolve, along with changes in the North American gas market. Despite increased production from Deep Panuke, the forecast for domestic production is that it will decline over time and Nova Scotia must look to other markets for long term gas supply. The expansion of production from the Marcellus in the U.S. Appalachia presents realistic opportunities for Heritage but pipeline capacity into New England is constrained, and new pipeline capacity has not materialized, although several open seasons have been announced to expand pipeline capacity into the region. The increased U.S. supply especially in the Marcellus Basin has had a dramatic effect on gas prices, pipeline flows, and supply availability.

Heritage has asked ICF to address a number of questions related to the benefit if any that Alton would bring to Heritage and its customers. The specific questions include.

a. Is natural gas storage in Nova Scotia beneficial to Heritage Gas and its customers? If so, does natural gas storage offer a short-term or a long-term benefit?
b. Would natural gas storage provide Heritage Gas and its customers with an increased security of supply? If so, what would be the estimated financial value of this security of supply?
c. If Heritage Gas entered into a contract for gas storage service, what would be the optimal level of natural gas storage that Heritage Gas should contract for? (This should include an optimal range (i.e. +/- 10% & 20% variation in forecasted load changes).
d. What would be the optimal maximum withdrawal / maximum injection quantity needed for Heritage Gas within the storage service contract?
e. What is the optimal amount of transportation capacity that Heritage Gas should contract for in order to reach supply basins / hubs?
f. What would be the estimated total cost to Heritage Gas to obtain natural gas storage services in Ontario (or another storage facility within close proximity)? That is, should Heritage contract for storage in another area of North America including total storage and transportation costs.
g. What would be the estimated total cost to Heritage Gas to utilize the LNG facility in Canaport as an alternative to the Alton natural gas storage project

The remainder of this report considers these questions in the following sequence. We first present ICF's updated North American gas supply outlook. This is relevant for this update given the options of securing gas priced in New England or gas priced in the Marcellus. We then consider the Alton proposal and present the results of the analysis under two alternative cases: New England-based gas purchases and Marcellus based gas purchases. These model results are used to estimate the optimal storage capacity and rates of injection and withdrawal under the Alton pricing proposal and using Heritage's updated gas demand forecast. We also use the model results to estimate the optimal amount of gas pipeline capacity that Heritage should acquire were Heritage to acquire gas from the Marcellus.

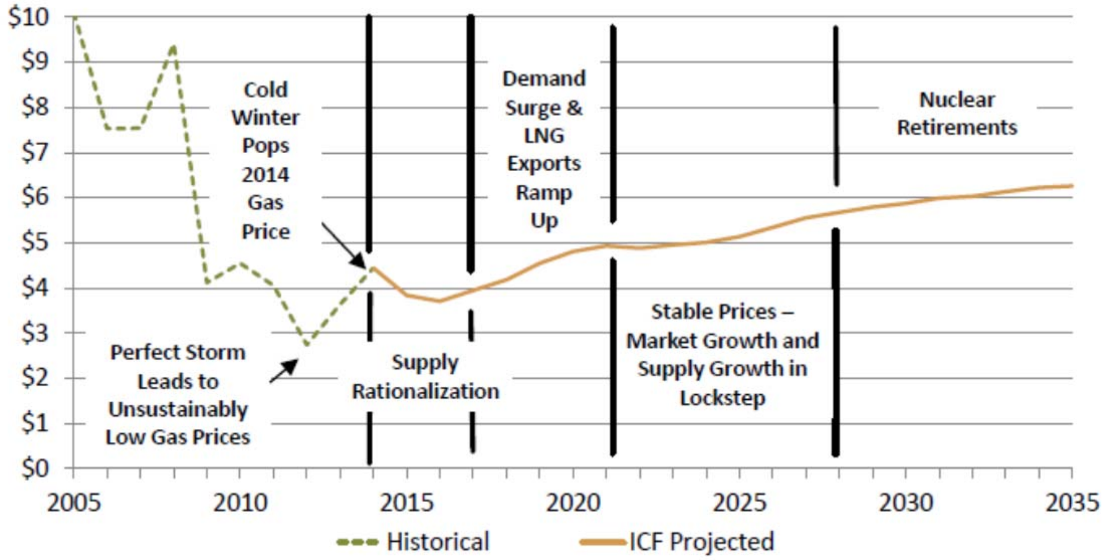
2. Gas Market Outlook

2.1 ICF Base Case Market Outlook

ICF's previous analysis was based on the first quarter 2013 Base Case. Overall, our current Base Case reflects few changes in the market, with one exception, which is important for this analysis. We have increased our forecast of production from the Marcellus. Despite a slight decrease in the Marcellus shale rig count over the past year, production has continued to increase. More wells are being drilled per active rig, and production per well has continued to increase. Wells in the Utica shale, which underlies the Marcellus and extends into eastern Ohio, have had a higher gas-to-oil production ratio than earlier expected. As a result of these trends, ICF has increased projected growth from Marcellus and Utica production by about 9 Bcfd over the previous release. Total Marcellus and Utica gas production is now projected to reach 20 Bcfd by 2016, 30 Bcfd by 2025, and 34 Bcfd by 2035.

The effect of this higher production outlook is both on prices and pipeline flows. Exhibit 2-1 shows our current gas price forecast for Henry Hub.

Exhibit 2-1: Average Annual Henry Hub Price in $2012 per MMBtu

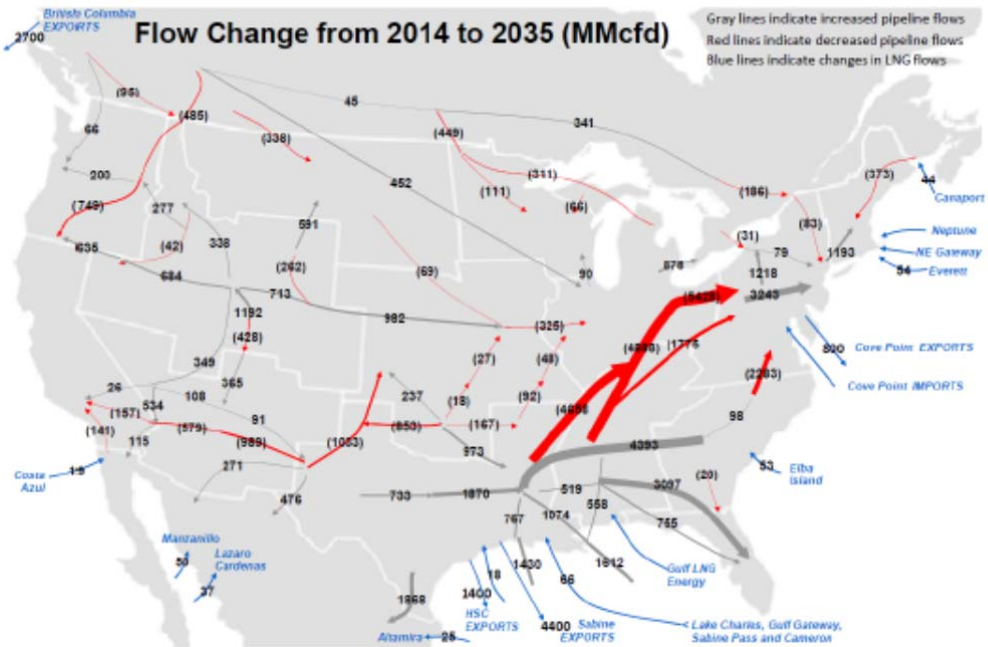


This forecast is based on a return to normal weather temperatures, even as the market recovers from the spectacular gas prices of the past winter, which was much colder than normal in much of the United States.

The long term effect of surging Marcellus and Utica production is shown in the exhibit on the following page which shows the change in gas pipeline flows between now and 2035. The arrows represent pipeline corridors for flows between regions. Gray arrows indicate increasing flow, with the total increase over the period indicated by the accompanying number. Red arrows indicate decreases in flows. Blue arrows show LNG flows. Flows are in millions of cubic feet per day (MMcfd).

Focusing on the northeast and the Maritimes, the forecast is for declining flows southerly over Maritimes and Northeast Pipeline (M&NP) and minimal imports through Canaport. The dramatic change is the large decline in flows from the south and southwest into the northeastern market. This is the effect of robust Marcellus production, which displaces the gas flowing on these pipes. Marcellus gas flows into the northeast, Ontario, and begins to flow westerly, backing out gas from the Rockies that had been flowing into the east. Our forecast shows gas out of the Marcellus increasing over the pipelines serving New York and New England.

Exhibit 2-2: ICF Base Case Pipeline Corridor Flows



Source: ICF International

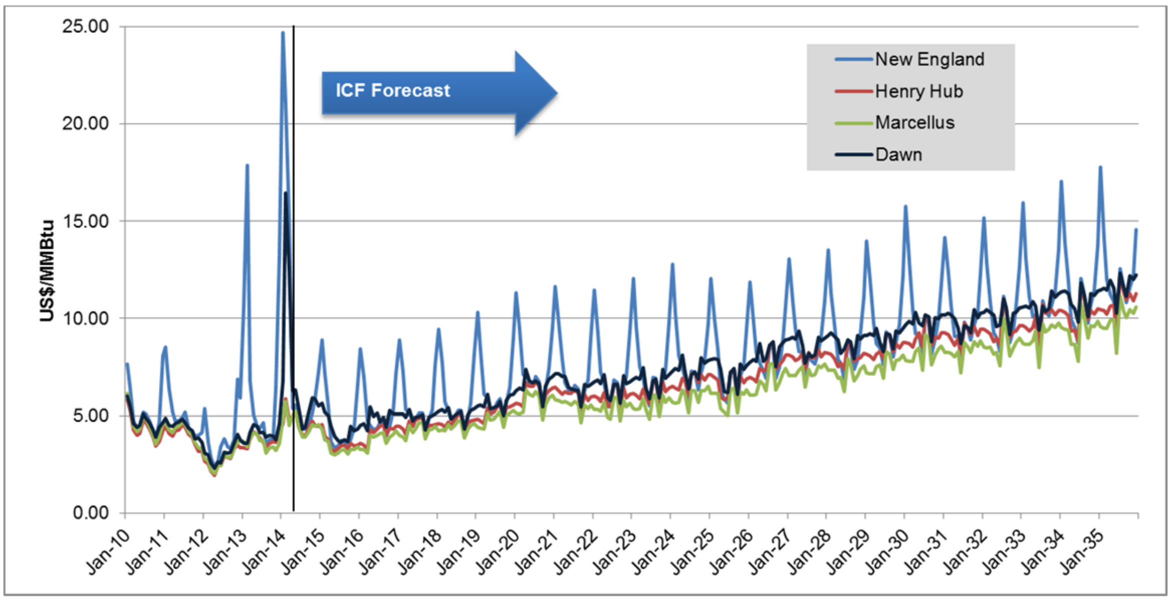
As production out of Marcellus and Utica continues to grow, more pipeline capacity will be needed to carry these supplies to market. New capacity is being added to get supply out of the producing regions into the mainline pipelines; with some capacity aimed at bypassing bottlenecks in the northeast and other projects facilitating reverse flows and new southern markets. Projects aimed at the northeast and potentially the Maritimes include:

- Algonquin Gas Transmission (AGT) – Algonquin Incremental Market (AIM) expansion of about 340 MMcfd or higher into New England from New Jersey
- AGT and Maritimes and Northeast Pipeline (M&NP)– Atlantic Bridge aimed at Maine and the Maritimes, about 200-300 MMcfd or higher depending on interest.
- Tennessee Gas Pipeline (TGP) – Bullet Line, interconnecting with M&NP at Dracut, between 600 MMcfd and 2.2 Bcfd, depending on interest.
- Portland Natural Gas Transmission (PNGTS) – an increase of about 140 MMcfd to 300 MMcfd total.

All of these expansions would require new upstream capacity to reach back into the Marcellus. It is our understanding that Heritage has been in discussions with some of the pipelines and has received notional prices for expanded capacity.

The exhibit below presents ICF's view on monthly gas prices at key locations relevant to this analysis: Henry Hub, Dawn, Marcellus, and New England.[1] The forecast for Marcellus and Henry Hub are virtually the same. The price for New England is significantly higher in winter relative to the other two locations but in summer, New England prices are closer to Marcellus and Henry Hub. The reason for the high winter prices is that our forecast presumes that expansions of pipeline capacity into New England will not be sufficient to meet the incremental demand of gas-fired power generators in New England who will bid up prices to high levels to secure gas for power markets. As a result, we expect to see a continued large basis spread between summer and winter prices in New England. This pattern has two implications for Heritage's decision-making on storage. If Heritage continues to buy gas in New England, the intrinsic value of storage is likely to be high, due to the difference between summer and winter prices. If Heritage instead were to secure gas in the Marcellus, the seasonality-based value of storage should be smaller due to less seasonal differentiation in prices, but the value of storage in the capacity planning context, i.e., balancing storage with pipeline capacity becomes more important. This value will be related to the costs of long haul gas transportation and the difference in Heritage's base gas sendout and its peak-day sendout.

Exhibit 2-3: ICF Natural Gas Price Forecast for Alternative Market Centers



The above exhibit illustrates significant differences between prices in the relevant markets for Heritage. As pointed out above, the New England market continues to show extreme summer winter volatility, even with the expansions into the market that ICF has forecast. Some summer winter spread is also seen in Dawn prices. More significant is the fact that Marcellus shows little seasonal difference at all, and is priced below Henry Hub for virtually the entire forecast. In summer, prices at all of the hubs are very close together.

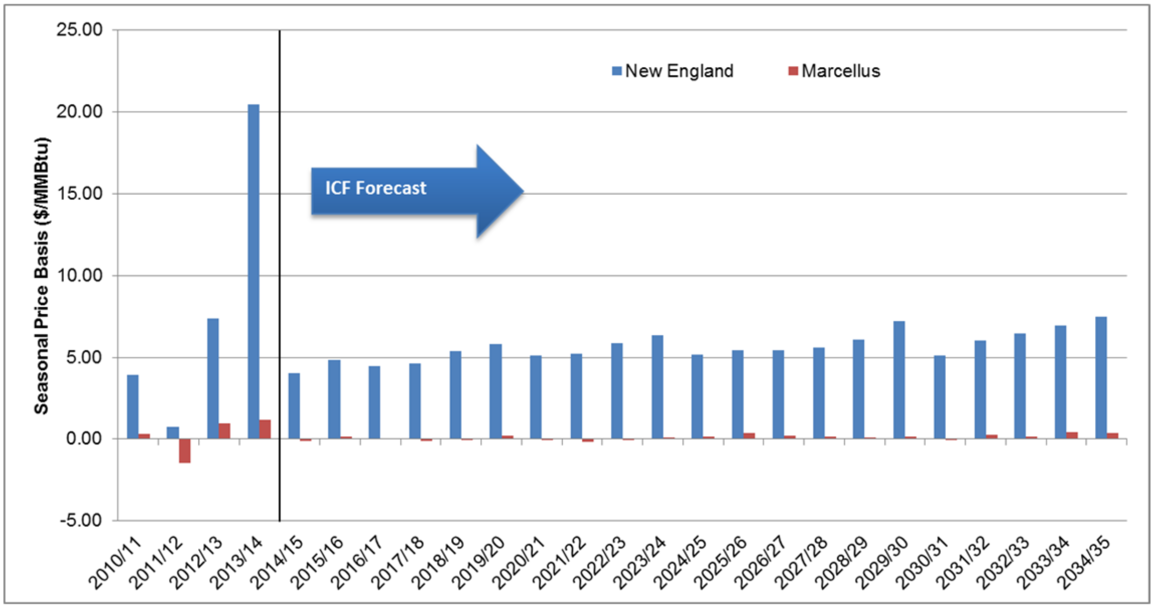
In ICF's Base Case the strength of the production in the Marcellus over the period puts downward pressure on Gulf Coast prices as well as prices in the Marcellus market centers. Flows from the Marcellus and Utica basins into Ontario at both Dawn and Niagara will increase, and the need for

[1] Marcellus hub is a northeast Pennsylvania node in the GMM© comparable to Dominion Southpoint and Leidy; New England is a node that can be compared to Algonquin City Gate, TGP Zone 6, and Dracut.

additional pipeline capacity between these market centers to accommodate the growth results in a significant positive basis between the two regions. Hence the projected increase in Dawn prices relative to Henry Hub.

The next exhibit shows ICF's forecast of the seasonal basis, or the price spread between the summer injection season and the winter withdrawal season for a *normal weather year*. We emphasize normal year because the last winter seasons have seen much higher prices in New England due to weather and pipeline constraints. The summer winter spread helps to determine the value of storage, where storage costs should be equal to or less than this spread.

Exhibit 2-4: ICF Forecast of Seasonal (January –Summer) Natural Gas Price Basis in New England



2.2 Demand Forecast

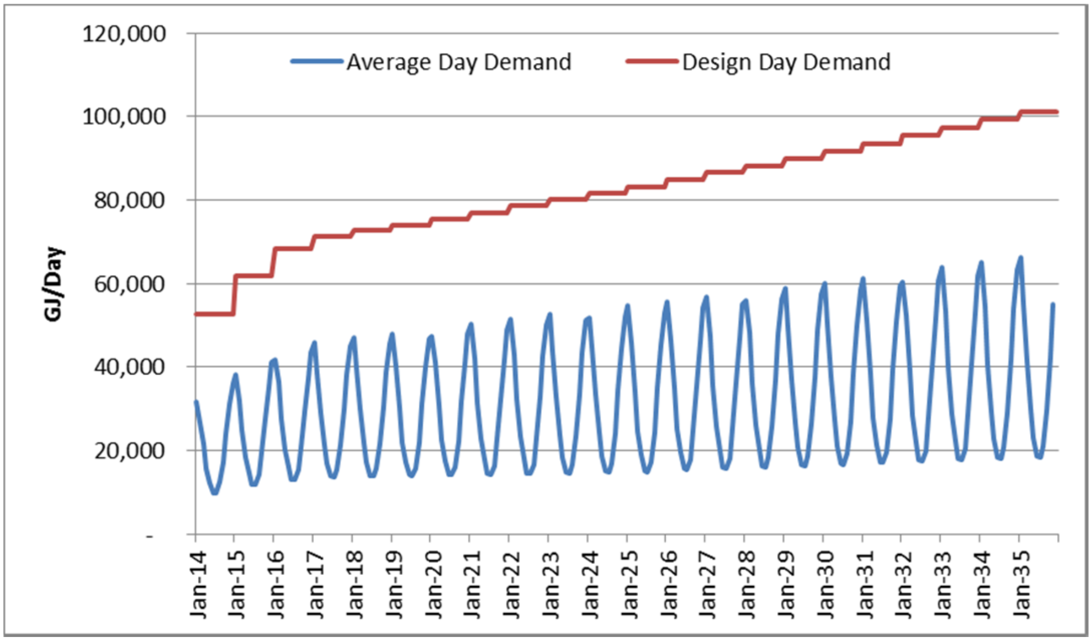
ICF used Heritage Gas' forecast of gas sendout between 2014 and 2025, then extrapolated through 2035 by using the last 3 years rate of growth in annual demand and kept the same monthly ratios to estimate monthly demand. The current forecast is higher than forecast used in the previous analysis.[2] Heritage Gas expects customer growth to drive annual demand to 10.1 million GJ per year by the end of 2017 when storage service would begin. This reflects a growth rate of about 10.7 percent per year between 2014 and the end of 2017, representative of the historical growth rate for Heritage. After 2017, annual demand is expected to grow by about 2 percent per year. This demand forecast represents normal weather temperatures. The ratio of summer low month average daily demand to winter peak month average daily demand will remain fairly steady at about one to three. The design day[3] sendout is estimated by ICF based on the demand outlook, customer counts, heating

[2] In the previous analysis, ICF generated the forecast based on current demand and Heritage growth rates. The current forecast is provided by Heritage through 2025.

[3] Design day is the highest peak day that a distribution company can expect based on the number of customers, customer profiles, and weather. Systems are sized, or designed, to meet a design day requirement which will be higher than a peak day under normal weather.

degree day forecasts (under normal weather). Design day is critical since it establishes the peak sendout requirement of the system.

Exhibit 2-5: Heritage Gas Demand Forecast (Normal Weather)



See Appendix table A-5 for the numbers underlying this exhibit.

3 The Value of Alton Storage to Heritage Gas

3.1 Alton Storage Proposal

Below in Exhibit 3-1, we provide the key elements of the Alton storage proposal used in ICF's modeling.

Exhibit 3-1: Summary of Revised Alton Storage Service Proposal

Contract Provision	Alton Proposal
Term of Service	20 years
Maximum Customer Inventory (MCI)	Not determined
Maximum Daily Injection Quantity	[redacted] by the Maximum Customer Inventory ("MCI"), subject to adjustment once the injection profile has been determined. Equivalent to 200 days at the maximum injection rate per day.
Maximum Daily Withdrawal Quantity	[redacted] by MCI, subject to adjustment once the withdrawal profile has been determined. Equivalent to 120 days at the maximum withdrawal rate per day.
Inventory Demand Rate ("IDR")	Based on the Target Project Cost and Initial Project Target Capacity, IDR is [redacted] per GJ of MCI per month. Annual cost is [redacted]
Escalation of IDR	[redacted] per year.
Injection Commodity Rate ("ICR")	[redacted] per GJ, escalated by change in the Nova Scotia All Items CPI over the previous contract year.
Withdrawal Commodity Rate ("WCR")	[redacted] per GJ, escalated by change in the Nova Scotia All Items CPI over the previous contract year.
Excess Injection Charge	[redacted] per GJ.
Excess Withdrawal Charge	[redacted] per GJ.
Injection Demand Rate	[redacted] per GJ.
Withdrawal Demand Rate	[redacted] per GJ.
Customer's Fuel Gas Quantity	2% of the volume of Gas delivered by Customer to the Alton Storage Facilities in a Gas Year (as defined in the Tariff).
Customer's Cushion Gas Quantity	Customer supplied, 25% of MCI.

This analysis expands on the previous analysis in 2013, where the value of gas storage is related to the difference in gas prices between summer when gas is injected in storage, and winter, when gas is withdrawn from storage. The total cost of storage, including pipeline transportation, expressed per GJ, must be less than the spread or basis between these seasonal prices for it to be beneficial to Heritage and its customers. Of course the future is unknowable and the value must be estimated based on expectations about future gas summer/winter basis. In addition, for this analysis we considered as part of the value of storage the basic capacity planning aspect that involves sizing storage to reduce the cost of long-haul firm transportation. Absent storage, planners would have to commit to long term contracts for firm transportation to meet design day sendout requirements; storage value therefore is related to the avoided pipeline costs.

Our approach in this study is similar to that in our 2013 study. In brief ICF used two proprietary natural gas market forecasting models to conduct the analysis. The updated April 2014 ICF Base Case forecast from the North American Gas Market Model (GMM©) provided the monthly price forecast. We used historic price volatility around the monthly prices to estimate daily price volatility. Heritage provided ICF with updated demand forecasts through 2025. Since the analysis runs through 2035, we extended the forecast by using the last 3 years rate of growth in annual demand and kept the same monthly ratios to estimate monthly demand. Then ICF used the Alton proposed storage rates to estimate the optimal level of MCI and rates of injection and withdrawal. This optimal level is that which minimizes Heritage's total cost of gas supply.

The analysis considers the value of storage under two sets of conditions. Under the first set, Heritage is assumed to buy gas at a New England index, where the price of gas over the course of the year varies with the price in New England, plus transportation to Nova Scotia and storage costs.

Under the second set of conditions, Heritage buys gas in Marcellus, at a Marcellus index (we have used Leidy), and transports the gas through New England to Nova Scotia. ICF used an estimate of gas transport costs, based on Heritage conversations with pipeline companies and ICF research. (See Exhibit 3-2). In this case ICF estimates the optimal level of MCI, injection, and withdrawal, plus the optimal level of pipeline capacity to meet gas demand. In this case, the value of storage is partially related to the intrinsic value based on seasonal price spreads, but also on the avoided costs of having to buy pipeline capacity to meet the full winter peak demand.

3.2 Gas Storage Scenarios

The analysis modeled six cases. We did not include the Dawn cases since at the prices shown for Dawn and pipeline costs, the model would never have chosen Dawn. Marcellus and New England offer the two lowest cost options.

1) New England Supply, No Storage: Assumes all gas is purchased at a New England index, but without the use of storage. This is a base case against which to evaluate the storage cases.
2) New England Supply, Optimized Storage: Total supply portfolio cost based on the storage proposal put forward by Alton. In this scenario, Injection and withdrawal capacity and cushion gas requirements change in proportion to the change in working gas capacity. Assumes all gas is purchased at a New England index.
3) Marcellus Supply, no storage: All supply comes from Marcellus over a pipe sized to meet design day demand.
4) Marcellus Supply with Optimized Storage : Uses Alton storage as proposed but optimizes pipe capacity and storage capacity for supply coming from Marcellus
5) Mixed Supply with Storage: Uses Alton storage as proposed but mixes supply sources between Marcellus and New England.
6) Mixed Supply without Storage: Purchase supply and pipeline capacity from both Marcellus and New England to minimize supply costs without storage.

Additional supply scenario parameters include:

- Withdrawals from Alton storage will be delivered to the Heritage service territory under the existing M&NP storage delivery tariff, which does not provide firm service on M&NP.
- Heritage is assumed to hold pipeline capacity on M&NP from New England under all options, and upstream of New England for the Marcellus options.

- Tolls used are those shown in exhibit 3-2 below. Pipeline transportation costs reflect the cost from Marcellus to points where new expansion projects have been announced. Tolls are held constant at current rates. For the final calculations of costs of storage, rates on U.S. pipelines are converted from U.S. units (U.S. $/MMBtu) to C$/GJ. The currency exchange rate is held constant at 1.0 to 1.0.[4]

Exhibit 3-2: Pipeline Tolls (USD/MMBtu)

Upstream Tolls including fuel A	Project Path	Path Tolls	Path Tolls including fuel B	MNP US + Can Tolls including fuel C	Total Path Tolls A+B+C
None	"TransCanada 2016 NCOS": Union (Dawn) + TCPL + PNGTS + MNP (from Westbrook)	UGL [redacted] Cdn/GJ; TCPL [redacted] Cdn/GJ; PNGTS [redacted] US/MMBtu	[redacted]	[redacted]	[redacted]
Constitution to Wright [redacted]	"Northeast Expansion Project": TGP (Wright) + MNP (from Dracut)	[redacted]	[redacted]	[redacted]	[redacted]
Millennium to Ramapo [redacted]/MMBtu	"Atlantic Bridge": Spectra (Ramapo) + MNP (from Beverly)	[redacted]	[redacted]	[redacted]	[redacted]

3.3 Analysis Results

The objective of the analysis was to estimate the optimal levels of reserved storage capacity, injection and withdrawal rates appropriate for the different sources of supply, under the theory that the source of supply would have implications for storage levels because of the cost of commodity and pipeline transportation. The terms "optimal" and "optimized" in this context refers to a level of storage that maximizes the benefits to Heritage and its customers at the expected levels of demand for gas, commodity price of gas, pipeline costs, and storage costs and storage operating rules offered by Heritage.

Several factors drive the results of this analysis. Focusing first on the storage decision, the following are most important to the answer.

- Heritage gas demand patterns, particularly the relationship of design day to average day demand.
- The cost of storage service, including any limits on storage withdrawal or deliverability. As a general matter, for any level of gas stored, higher deliverability from storage would be more beneficial than less.

[4] In the last 24 months the exchange rate has fluctuated considerably, from 0.97:1 to 1.11:1. Recently it appears to be heading back down and is about 1.06:1. To simplify the analysis we kept it at 1:1. See http://www.oanda.com/currency/historical-rates/, retrieved July 10, 2014.

- The summer/winter price spread or basis sets the "intrinsic" value of storage .
- The cost of firm pipeline capacity connecting to the source of gas supply. The higher the cost of firm pipeline capacity the more important storage is for minimizing total supply costs, since storage allows Heritage to better optimize its pipeline capacity.
- The cost of the gas at the receipt points into the pipeline.

3.3.1 Optimized Storage Capacity

Based on our analysis, ICF concludes that holding Alton storage capacity will reduce the overall Heritage Gas supply portfolio costs. The resulting total costs are shown in exhibit 3-3 below. The total portfolio cost includes the cost of storage service, cushion gas, gas supply, and pipeline costs. As shown in the exhibit, in all cases, storage will reduce costs.

Exhibit 3-3: Average Annual Total Supply Portfolio Costs with and without Storage (000 $)

	New England Supply Only		Marcellus Supply Only		Mixed Supply	
Period	Optimized Storage	No Storage	Optimized Storage	No Storage	Optimized Storage	No Storage
2017/18 to-2021/22	$89,124	$105, 560	$104,434	$137,899	$89,124	$105,560
2022/23 to 2026/27	$109,396	$128,111	$125,831	$162,464	$109,396	$128,060
2027/28 to 2031/32	$142,726	$164,443	$161,3667	$200,544	$142,726	$163,887
2017/18 to 2034/35	**$123,548**	**$143,585**	**$140,819**	**$178,135**	**$123,548**	**$142,994**
Storage Benefit	$20,037		$37,316		$19,446	

Comparing the cases, buying gas in New England is the lowest cost option. (Note that in the mixed cases with optimized storage, where we allowed the model to "choose" some combination of Marcellus and New England, the model chose only New England, hence the storage columns have the same value.) The no storage options are higher cost for two reasons. First Heritage would have to buy pipeline capacity from the source of gas to the city gate to meet design day sendout requirements. Second, storage would allow Heritage to optimize purchases by buying more gas during the low cost summer months and storing it for use in the high cost winter months.

The optimized storage capacity for the three different supply portfolio scenarios utilizing storage are shown in exhibit 3-4 below. The Mixed Supply case is identical to the New England Supply case since under this case, the model only buys gas in New England. Hence the storage capacity represents a gas purchasing strategy appropriate to a New England supply.

ICF's supply portfolio optimization analysis performed for Heritage indicates that Heritage Gas should hold between [redacted] and [redacted] of Alton storage capacity in order to minimize supply portfolio costs under normal weather conditions while maintaining sufficient firm natural gas deliverability to meet design day demand. To plan for weather extremes, ICF recommends adding an additional [redacted] of storage capacity.

Exhibit 3-4: Average Optimized Alton Storage Capacity – Normal Weather (GJ)

Year	New England Supply	Marcellus Supply	Mixed Supply
2017/18 - 2021/22 Average	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27 Average	[redacted]	[redacted]	[redacted]
2027/28 - 2031/32 Average	[redacted]	[redacted]	[redacted]
2017/18 - 2034/35 Average	[redacted]	[redacted]	[redacted]

The source of supply affects the optimal amount of storage capacity. The optimal amount of Alton storage capacity increases when supply is from the Marcellus because of the high cost of pipeline capacity from Marcellus to the city gate. The optimal solution is one that minimizes pipeline costs consistent with design day deliverability and replacing the pipeline capacity with storage.

At these levels of storage capacity, the injection and withdrawal rates would be as follows in exhibit 3-5. These rates use Alton's proposed ratios for establishing maximum withdrawal [redacted]) and injection [redacted] (Refer to Exhibit 3-1.)

Exhibit 3-5: Implied Average Injection and Withdrawal Rates

Averages:	New England Supply	Marcellus Supply	Mixed Supply
Withdrawal Rate (GJ/d)			
2017/18 - 2021/22	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27	[redacted]	[redacted]	[redacted]
2027/28 - 2031/32	[redacted]	[redacted]	[redacted]
2017/18 - 2034/35	[redacted]	[redacted]	[redacted]
Injection Rate (GJ/d)			
2017/18 - 2021/22	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27	[redacted]	[redacted]	[redacted]
2027/28 - 2031/32	[redacted]	[redacted]	[redacted]
2017/18 - 2034/35	[redacted]	[redacted]	[redacted]

3.3.2 Impact of Weather Uncertainty on Storage Capacity

ICF ran optimized storage scenarios for 30 different actual historical weather patterns (1981 – 2010) for the three year forecast period including 2017/18, 2018/19 and 2019/20. Exhibit 3-6 below illustrates the range of economically optimized storage capacity if actual winter weather were used rather than the normal (30 year average). The exhibit shows what the level of storage should be for each of the three winter years above if the winter were like the winter of the years across the X-axis. For New England and the Mixed Supply options, the range can be between [redacted] and [redacted] for Marcellus supply, the range is much smaller around [redacted] The difference is due to the swings in seasonal prices seen in New England, caused by the constraints on gas pipeline capacity into the region. When weather variability is added, it shows that there would be times when higher levels of storage are justified. exhibit 3-7 shows the average impact on the storage capacity across all the weather cases. Based on this analysis, ICF suggests that Heritage add an extra [redacted] of storage capacity for extreme weather.

Exhibit 3-6: Impact of Weather on Optimized Alton Storage Capacity (GJ)

[redacted]

Exhibit 3-7: Average Impact of Weather on Optimized Alton Storage Capacity (GJ)

	New England Supply	Marcellus Supply	Mixed Supply
Normal Cases			
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
Weather Cases			
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
Impact of Weather Volatility on Storage Requirements			
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]

3.3.3 Enhanced Injection and Withdrawal Rates

Alton has presented Heritage with rates for injection and withdrawal where injection is set at [redacted] of the MCI and maximum withdrawal is set at [redacted] of MCI. The withdrawal rate is of primary interest since it interacts with the MCI and pipeline capacity to set the deliverability of gas into the city gate for meeting design day requirements. In principle, a higher withdrawal rate would allow Heritage to make greater use of its storage capacity (MCI). Based on the Alton storage proposal, at the maximum withdrawal rate Heritage would have the equivalent of 120 days of storage deliverability. (Of course the actual period for withdrawals runs from November 1 through March 31, or 151 days.) Heritage requested that ICF determine whether additional injection and withdrawal capability would increase the value of Alton storage. Using the same pricing offered by Alton of [redacted] for injection and the same for withdrawal, we have estimated the effects of the higher levels of deliverability (withdrawal) from storage.

To evaluate higher levels of deliverability, ICF increased the withdrawal rates under the optimal storage volumes (MCI) estimated in Exhibit 3-4 by increments of 25 percent and re-optimized the storage analysis to determine the savings from higher levels of maximum withdrawal. The results are shown below in exhibit 3-8. The table suggests that for New England supply, the benefits of higher deliverability increase at each level of increase, but at a diminishing amount. For Marcellus, benefits increase significantly with each step increase in deliverability.

Exhibit 3-8: Average Annual Total Supply Portfolio Costs at Higher Levels of Storage Deliverability (000 $)

	Alton Deliverability	25% Higher Deliverability	50% Higher Deliverability	75% Higher Deliverability	100% Higher Deliverability
New England Supply					
2017/18 - 2021/22	$89,124	$87,387	$85,691	$84,781	$84,509
2022/23 - 2026/27	$109,396	$107,438	$105,466	$104,217	$103,689
2027/28 - 2031/32	$142,726	$140,511	$138,193	$136,638	$135,976
2017/18 - 2034/35	**$123,548**	**$121,492**	**$119,386**	**$118,008**	**$117,453**
Benefit Increase over Alton		**$2,056**	**$4,162**	**$5,541**	**$6,095**
Marcellus Supply					
2017/18 - 2021/22	$104,434	$102,496	$100,478	$98,461	$96,443
2022/23 - 2026/27	$125,832	$123,626	$121,329	$119,032	$116,735
2027/28 - 2031/32	$161,367	$158,845	$156,219	$153,592	$150,966
2017/18 - 2034/35	**$140,819**	**$138,502**	**$136,088**	**$133,675**	**$131,261**
Benefit Increase over Alton		**$2,317**	**$4,731**	**$7,144**	**$9,558**

Higher deliverability storage has significant value to Heritage Gas. The value is created in two ways. First, the increase in deliverability reduces the amount of storage capacity Heritage needs to purchase in order to maintain the same level of design day deliverability. ICF estimated this by re-optimizing the model around higher levels of withdrawal capability. Second, higher rates of withdrawal allow Heritage to avoid having to buy gas in the market on days when gas prices are high. In the winter, Heritage would both buy gas on the open market and withdraw from storage. The higher deliverability allows Heritage to reduce open market or contracted purchases indexed to the market during the highest price days during the winter. The ability to purchase additional gas on the lowest gas price days of the year also adds some additional value.

Heritage should seek a higher level of maximum withdrawal from Alton at the current proposed price of [redacted]

3.3.4 Source of Natural Gas Supply and Pipeline Capacity

Exhibit 3-9 presents our estimates of the level of gas pipeline capacity associated with the respective levels of gas storage and withdrawal. In the no-storage cases, long haul gas pipeline capacity must equal the design day requirements of the Heritage system, thus for both the no-storage cases, the pipeline capacity is the same. In the storage cases, the pipeline capacity is optimized around the gas prices, storage capacity, and withdrawal rate. In this case pipeline capacity is sized to operate at a high load factor that delivers gas to the city gate in winter, supplemented by gas from storage, and refills storage in the off peak season.

Exhibit 3-9: Gas Pipeline Capacity for Optimized Storage (GJ/d)

Years	New England Supply Optimized Storage	New England Supply No Storage Capacity	Marcellus Supply Optimized Storage	Marcellus Supply No Storage Capacity
2017/18 - 2021/22 Average	[redacted]	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27 Average	[redacted]	[redacted]	[redacted]	[redacted]
2027/28 - 2031/32 Average	[redacted]	[redacted]	[redacted]	[redacted]
2017/18 - 2034/35 Average	[redacted]	[redacted]	[redacted]	[redacted]

We do not show the mixed supply case because the optimized value is the same as the New England supply above and the mixed supply case also equals [redacted] for the no storage option.

3.4. Summary and Uncertainties

The assessment of the value of Alton storage to Heritage Gas is based on a long term forecast of Heritage Gas demand growth, North American and New England and Atlantic Canada natural gas market conditions, and seasonal and annual natural gas market prices. ICF concludes that Alton storage reduces supply costs in all cases; Heritage should buy more than [redacted] of storage capacity (MCI); a higher rate of deliverability than what Alton has offered [redacted] further reduces costs as long as it is at the same rate of [redacted] and buying gas in New England is lower cost than buying gas in Marcellus due to the high pipeline transportation cost.

The basic conclusion that use of Alton storage as part of the Heritage Gas supply portfolio will reduce the total portfolio supply costs is robust across the full range of supply and storage scenarios considered. Based on our analysis, we would expect Heritage to see cost savings from the first year of storage service through the length of the storage contract.[5] The basic conclusion that use of Alton storage capacity would reduce overall supply costs also holds even if Heritage Gas demand growth is slower or faster than projected, although the optimum amount of storage capacity would vary for alternative demand scenarios.

The conclusion also holds for the case where seasonal gas price basis (i.e., the difference between peak winter prices and low summer prices) were to narrow. Market storage allows Heritage to

[5] Based on normal weather. Normal year to year variation in weather patterns and natural gas markets can impact the value of storage in any given year.

optimize its commitment to high cost long term firm transportation. Volatility in gas prices nevertheless contributes to storage value.

An important component of storage value is how it allows Heritage to maximize gas purchases when the price is low and inject into storage and minimize gas purchases when prices are high and withdraw from storage. ICF's modeling uses an optimization routine that executes purchases optimally on a daily basis. This probably overstates the savings from storage somewhat. Most utilities buy gas on a monthly basis, paying a single price for gas for the month. ICF tested this option by having the model buy gas in two tranches; one at a level basis for an average monthly price and another tranche taking advantage of the daily pricing optimization. The results were slightly higher portfolio costs than in the cases described in this report but still showing a benefit from storage. Thus while Heritage may execute a purchase pattern different from what we have modeled, we are confident that it will result in storage generating savings for Heritage and its customers.

4 Heritage Questions

ICF has been asked to address the following questions raised by Heritage.

a. Is natural gas storage in Nova Scotia beneficial to Heritage Gas and its customers? If so, does natural gas storage offer a short-term benefit or a long-term benefit?

Consistent with our previous report conclusions, ICF believes that storage would provide both a short term and long term benefit to Heritage and its customers.

b. Would natural gas storage provide Heritage Gas and its customers with an increased security of supply? If so, what would be the estimated financial value of this security of supply?

As a general principle, we believe storage would help increase the security of supply. This is consistent with our previous finding.

The need for supply security arises from two concerns: that Sable Offshore Energy Project (SOEP) will experience a disruption or there is some pipeline upset that interrupts gas supply. While the latter is very rare, the former has occurred from time to time throughout the history of SOEP. In both instances, the reductions in gas supply tend to be short lived and we are not aware that Heritage has experienced any loss of ability to meet customer needs in the past. (But we are aware that Heritage has had gas supply contracts that were "full requirements", i.e., the supplier was obligated to deliver full daily volumes to the city gate.)

Unlike power disruptions, gas disruptions rarely lead to loss of load. This is partly due to the nature of gas pipelines, where line pack can make up for modest disruptions, and partly due to the ability of pipelines to get around problem areas and accept flows from other directions. This has occurred in Nova Scotia when SOEP has been down and gas flowed north from Maine into M&NP-CA.[6] Additionally, gas distribution companies may have other means of managing supply disruption or design day sendout. These options include reducing deliveries to interruptible customers on an interruptible tariff in order to divert gas to firm customers. This is frequently the case where industrial or large institutional customers opt for a lower tariff rates in return for occasionally having their gas supply interrupted. These customers will have installed back-up fuel supply, usually heating oil or diesel. Another way to manage peak sendout or supply disruptions is by having a LNG or propane air peak shaving facility. These facilities are designed to run a very few hours or days per year and supplement supply on the very coldest peak demand days or provide supply during a disruption.

The value of storage as supply security is set by the alternatives to storage to meet any shortfalls in gas supply. We have identified three alternatives relevant to Heritage.

1. Heritage can rely on spot gas purchases to maintain reliability during times of SOEP production dislocation. This presumes the supply disruption would not affect M&NP

[6] To what extent this will occur in the future is uncertain. What is more certain is that ICF and others have forecast declining production from Deep Panuke which should cause Nova Scotia buyers to look to other sources of supply. See ICF's report to the Nova Scotia Department of Energy on the future of gas supply in Nova Scotia, July 2013.

deliverability to the point where it could not supply spot gas. The risk around this cost is that if there is a disruption, all buyers will be in the market bidding up the price of gas on the daily spot market and the price is likely to be much higher than we provide below.

Example of cost/value. In this option the value of supply security is essentially cost of spot gas and the incremental cost of gas transportation. The current futures contract (as of May 2) for gas delivered in New England in January is estimated at $8.77/GJ. Add to this the cost of transportation on M&NP and the delivered cost to Heritage would be about $10.00/GJ. (Based on NYMEX futures price for HH reported in Gas Daily, May 5, 2014 plus ICF forecast basis.) This is a first of the month price. Daily prices would be higher or lower depending on weather and demand/supply conditions. Heritage could fix this price with swap contracts. The strategy around this approach would have to be more developed. In the absence of hedging or some kind of on-purchase option contract (which could be expensive) Heritage would be in the market buying gas on a daily basis along with many others in Nova Scotia during a supply disruption and could face very high prices. In the last winter, prices in New England hit over $80 per MMBtu, as one extreme example of how high prices could rise in the daily spot market.[7]

2. Heritage could utilize fuel oil as a proxy for underground gas storage.

   Heritage might encourage certain classes of its customers to switch to alternative fuels, principally distillate fuel oil, during periods of peak demand or system stress. Normally in gas distribution systems interruptible customers receive a lower rate in return for allowing the utility to interrupt them. In this case, the customer is responsible for installing back-up fuel switching capability and maintaining an inventory of fuel. Were this to be the case for Heritage, the avoided costs disruption would be shared with these interruptible customers. As an alternative, Heritage could assist in the cost of installing back-up fuel capability and buying or subsidizing the cost of fuel oil for those who agree to participate. At present, Heritage does not have interruptible customers but there are some customers with fuel oil back up.

   Example of cost/value. For heating oil, the cost is estimated at $21.90/GJ. (Based on CME New York Harbor futures for HO for January 2015, plus transport to N.S.) For heavy fuel oil (HFO or #6) the cost is $14.60/GJ. (Based on CME Gulf Coast No. 6 futures price for #6, 3.5% sulfur, delivered to N.S.) These costs are likely to be understated because of the cost of installing fuel switching capability and the additional O&M costs associated with maintaining and operating the equipment.

3. Heritage could develop a small scale LNG liquefaction and regasification peak-shaving plant or a propane-air peak shaving system to alleviate shortages during outages (or meet needle peak demand).

   Example of cost/value. The cost estimate for a LNG peak shaving facility is based on the costs developed for the Yankee Waterbury facility. This is a 1,200,000 Mcf storage facility with a sendout capability of about 150,000 Mcf per day over 8 days.

[7] ***Gas Daily***, Jan. 23, 2014, quoted prices at Dracut and other New England pricing points in excess of $80 per MMBtu. There were many days when prices where in the $20-$30 range or higher.

The cost of this facility was $108 million in 2005. The sendout capability is for 8 days. Our estimate of the costs of a liquefaction, storage, and regas plant expressed on a per Mcf basis to account for the different scale of a facility for Heritage is shown in Exhibit 4-1.

Exhibit 4-1: LNG Peak Shaving Cost Estimate

Typical capital costs/Mcf capacity full cycle plant	$ 90.00
Capital Recovery Factor	0.16
$/Mcf stored	
Capital	$14.40
O&M	$0.70
Gas itself	$ 6.40*
Losses (@12%)	$ 0.54
Total per Mcf	$22.27
Total per GJ	~$20.60

*ICF forecast price of gas in N.E. plus M&NP tariff to N.S.

In summary, the value of storage as supply security depends on the alternatives Heritage could use to meet unexpected outages of supply. These tend to be rare, but the costs of not having gas are very high. We have estimated value of supply security in gas storage to be as follows.

1. **Spot gas:** Spot gas values vary, but based on the forwards, and assuming a hedging program, the cost could be about $10.00 per GJ, assuming a winter outage, and no price spike. Without hedging the cost could be as high as gas was this last winter in New England, which was over $80 per GJ and many days in the $20+ per GJ range.

2. **Fuel Switching:** Based on the alternative fuel for dual fueled customers: for heating oil customers, using NYMEX futures, approximately $21.90 per GJ; for heavy fuel oil customers or the NSPI option, $14.60 per GJ.

3. **LNG Peak Shaving:** Estimated to be approximately $20.60 per GJ, based on average design and costs for a liquefaction, storage, and regasification plant.

Thus the range would be between $10.00 per GJ and $21.90 per GJ.

We have not tried to estimate the value of supply security on the loss-of-load basis – i.e., what would be the costs to Heritage's customers were the system to depressurize and customers lost their gas service entirely requiring a relighting of parts of the system. We believe this would be a very high cost. In an ongoing study in the U.S.,[8] the loss of industrial customers is estimated at $150.00 per MMBtu ($142.86 per GJ), based on how industries with no back-up fuel can respond to loss of gas supply by shifting production to other periods when gas service is lost. Power generators' loss of gas cost are estimated at $300

[8] ICF is doing work for the Eastern Interconnection States Planning Council (EISPC) on similar issues where we are estimating how much gas pipeline capacity to build to avoid outages and severe weather. That study is doing a probabilistic assessment to find the optimum level of capital investment to protect against extreme weather conditions, where deciding to not serve load is an option.

per MMBtu ($285.70 per GJ), based on what independent system operators are willing to pay per MW for security ($3,000 at a 10,000 Btu/kWh heat rate, yields $300.) On some systems it could be higher. The commercial loads would be higher still, and in Heritage's case the hospitals that have no back-up fuel would be considerably higher. Loss of service into residential customers would be very high due to safety issues and re-lighting costs.

c. If Heritage Gas entered into a contract for gas storage service, what would be the optimal level of natural gas storage that Heritage Gas should contract for? (This should include an optimal range (i.e. +/- 10% & 20% variation in forecasted load changes).

The level of storage will depend on the selected mix of gas supply and pipeline transportation. ICF recommends a New England supply focus with a possible link to Marcellus, for a smaller amount of pipeline capacity and supply. The recommended level of capacity is:

Exhibit 4-2: Storage Level (GJ)

	Low 2017/18-2021/22 Average	Ave 2017/18 -2034/35 Average	High 2027/28 – 2031/32 Average
New England	[redacted]	[redacted]	[redacted]
Marcellus			

To this amount we would add [redacted] for weather

d. What would be the optimal maximum withdrawal / maximum injection quantity needed for Heritage Gas within the storage service contract?

The optimum maximum withdrawal/injection quantity cannot be estimated without knowing the cost of any increase in withdrawal/injection quantity above the Alton base offer. However, ICF's analysis suggests that a 75 percent increase in the maximum withdrawal rate would optimize the value of the storage service.

e. What is the optimal amount of transportation capacity that Heritage Gas should contract for in order to reach supply basins / hubs?

For the New England Hub only: between [redacted] and [redacted]
For the Marcellus Hub only: between [redacted] and [redacted]

f. What would be the estimated total cost to Heritage Gas to obtain natural gas storage services in Ontario (or another storage facility within close proximity)? That is, should Heritage contract for storage in another area of North America including total storage and transportation costs.

Ex franchise[9] storage rates in Ontario around Dawn are typically negotiated and not publicly available. ICF, therefore, has used a storage service offered by Enbridge, Rate 330, Large Volume Rates, Full Cycle.[10] This rate would have the following characteristics, expressed in

[9] Ex franchise refers to those storage services not dedicated to the local distribution companies' franchise services to customers. Ex-franchise storage tolls are market-based and negotiated.

[10] See Enbridge website: https://www.enbridgegas.com/businesses/accounts-billing/gas-rates/large-volume-rates/rate-330.aspx, retrieved May 5, 2014.

$/GJ instead of $/1000m3. To estimate storage costs we have adopted an Alton-like configuration with [redacted] GJ of storage space and [redacted] of withdrawal capacity. Our estimate of the costs are below.

Exhibit 4-3: Ontario Storage Cost Estimate

Cost elements	$/1000m3	$/GJ
Storage Capacity/mo.	1.9451	0.051539
Withdrawal Capacity/mo.	215.1871	5.701831
Commodity Injection/unit	6.68	0.177001
Total fixed cost at [redacted] and [redacted] withdrawal		[redacted]
Fixed cost/ GJ		[redacted]
Total w/Commodity injection		[redacted]
Total storage Cost/year		[redacted]

We are aware that these rates are significantly higher than customers are currently paying for storage capacity in Ontario. Based on Union Gas information recently filed before the NEB, current storage values are around $0.54/GJ.[11] While these rates may not be available for long term contracts, they represent a reasonable lower bound on what Heritage would expect to pay.

Thus, assuming that Heritage would acquire the same amount of storage as it would from Alton, total storage costs would be between [redacted] and about [redacted], or about [redacted] to [redacted] per GJ for storage. Getting the gas to the city gate, however, will require Heritage to buy pipeline capacity for the full design day requirement, or about 72,000 GJ/d. Assuming a cost of [redacted], including fuel, the cost of transportation would add another [redacted], for a total storage delivery cost of between $78 million and $81 million per year, not including gas cost which is forecast to be higher at Dawn than in the Marcellus over the time period.

The major problem with buying gas storage in Ontario and not in Nova Scotia is that it provides no opportunity to save on the costs of pipeline capacity, which a local storage service would provide. In addition it leaves Heritage's full requirements susceptible to any disruption on a long pipeline route – a small risk we believe, still a risk.

g. What would be the estimated total cost to Heritage Gas to utilize the LNG facility in Canaport as an alternative to the Alton natural gas storage project

ICF is not aware that Canaport has offered its facility for storage service in the local market. There are no liquefaction facilities at the plant. We are not aware that Canaport would take delivery of third party LNG for regasification and re-delivery to the third party (i.e., Heritage.) Such an arrangement would require quick redelivery, since LNG storage usually involves regasification of the stored LNG within a short period of time, typically about 10 days, to make room for the next delivery. It is possible that Canaport would operate on a longer term storage basis. Since there are no liquefaction facilities at Canaport, the "storage"

[11] See EB-2014-0145 - 2013 Deferral Disposition Rate Case, p. 25 found at http://www.uniongas.com/about-us/regulatory/rate-cases/eb-2014-0145-2013-deferral, retrieved May 8, 2014.

would have to be essentially a LNG peaking service where Heritage would be purchasing imported gas from Canaport to meet winter demands. Theoretically this would entail the following calculations.

Assuming a cost based approach, several assumptions would have to be made. First, we assumed that the service would use a world LNG price, most likely related to the National Balancing Point (NBP) in the U.K.. This is the U.K. spot price that would set the value of gas delivered into the U.K. at one of the import terminals or via pipeline. Then we estimated a transportation cost to Canaport from the U.K. Next we estimated a regasification cost at Canaport. Then we added a cost of transport on Brunswick Pipeline, plus transport on M&NP-US and M&NP-CA.[12] These estimated costs are in the exhibit below. Our gas price in the exhibit is a January 2015 futures price for the NBP. The other costs are ICF estimates or from the M&NP tariff.

Exhibit 4-4: Canaport Peaking Service ($/GJ)

Component	Cost Basis Value
Gas Price	$10.83
Transport to Canaport	$0.67
Regasification	$0.45
Brunswick Pipeline	$0.20
M&NP US	$0.52
M&NP CA	$0.72
Estimated Cost	$13.39

In the alternative, Repsol could sell gas to Heritage at its opportunity cost plus recovery of fixed pipeline and other expenses. This could include a New England price plus transportation costs over M&NP to the city gate. We would expect that such opportunity costs would be charged only when they exceed the costs estimated above.

In either case, if this were to be an ongoing long term service, Heritage would have to purchase additional firm pipeline capacity on M&NP to meet design day requirements.

[12] The NBP price taken from ICE, https://www.theice.com/marketdata/reports/datawarehouse/ConsolidatedEndOfDayReportPDF.shtml

Appendix A: Optimized Gas Supply Pipeline and Storage Capacity and Portfolio Costs for Alternative Scenarios

Exhibit A-1: Heritage Gas Supply Optimized Storage Capacity (GJ)

	New England Supply	Marcellus Supply	Mixed Supply
2017/18	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]
Averages:			
2017/18 - 2021/22	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27			
2027/28 - 2031/32			
2017/18 - 2034/35	[redacted]	[redacted]	[redacted]

Exhibit A-2: Optimized Pipeline Capacity for Alternative Scenarios (GJ/d)

					Diversified Supply - Optimized Pipe w/Storage Capacity		Diversified Supply - Optimized Pipe w/o Storage	
	New England Supply Optimized Pipe w/Storage	New England Supply Optimized Pipe w/o Storage	Marcellus Supply Optimized Pipe w/Storage	Marcellus Supply Optimized Pipe w/o Storage	Capacity from New England	Capacity from Marcellus	Capacity from New England	Capacity from Marcellus
2017/18	[redacted]							
2018/19								
2019/20								
2020/21								
2021/22								
2022/23								
2023/24								
2024/25								
2025/26								
2026/27								
2027/28								
2028/29								
2029/30								
2030/31								
2031/32								
2032/33								
2033/34								
2034/35								
Averages:								
2017/18 - 2021/22								
2022/23 - 2026/27								
2027/28 - 2031/32								
2017/18 - 2034/35								

Exhibit A-3: Supply Portfolio Costs

	New England Supply Alton Storage	New England Supply No Storage Capacity	Marcellus Supply Alton Storage	Marcellus Supply No Storage Capacity	Mixed Supply Alton Storage	Mixed Supply No Storage
2017/18	$81,045,188	$94,823,489	$95,439,859	$127,463,506	$81,045,188	$94,823,489
2018/19	$80,895,304	$96,563,533	$96,397,673	$129,378,820	$80,895,304	$96,563,533
2019/20	$87,811,955	$107,735,166	$103,530,939	$137,652,530	$87,811,955	$107,735,166
2020/21	$98,445,916	$114,044,711	$114,235,754	$148,075,671	$98,445,916	$114,044,711
2021/22	$97,423,978	$114,635,480	$112,563,565	$146,926,047	$97,423,978	$114,635,480
2022/23	$99,173,307	$117,851,277	$114,725,490	$149,774,072	$99,173,307	$117,851,277
2023/24	$104,616,990	$124,397,375	$119,299,203	$155,140,611	$104,616,990	$124,268,130
2024/25	$110,124,731	$127,208,883	$126,788,677	$163,025,476	$110,124,731	$127,208,883
2025/26	$109,366,434	$125,750,049	$127,119,533	$164,649,224	$109,366,434	$125,750,049
2026/27	$123,700,689	$145,347,483	$141,223,104	$179,729,267	$123,700,689	$145,222,800
2027/28	$130,578,831	$148,409,635	$148,914,365	$187,041,630	$130,578,831	$148,409,635
2028/29	$134,419,939	$159,317,984	$151,248,916	$189,907,429	$134,419,939	$158,261,239
2029/30	$143,567,660	$169,543,066	$161,155,455	$200,550,722	$143,567,660	$167,819,962
2030/31	$149,916,649	$169,498,276	$170,148,141	$209,348,599	$149,916,649	$169,498,276
2031/32	$155,147,434	$175,445,892	$175,367,646	$215,873,537	$155,147,434	$175,445,892
2032/33	$163,429,554	$187,062,685	$181,956,004	$223,015,168	$163,429,554	$185,682,392
2033/34	$175,181,897	$206,796,207	$194,346,861	$236,552,143	$175,181,897	$200,889,913
2034/35	$179,008,962	$200,093,066	$200,284,203	$242,326,130	$179,008,962	$199,772,704
Averages:						
2017/18 - 2021/22	89,124,468	105,560,476	104,433,558	137,899,315	89,124,468	105,560,476
2022/23 - 2026/27	109,396,430	128,111,014	125,831,201	162,463,730	109,396,430	128,060,228
2027/28 - 2031/32	142,726,103	164,442,971	161,366,905	200,544,383	142,726,103	163,887,001
2017/18 - 2034/35	**$123,547,523**	**$143,584,681**	**$140,819,188**	**$178,135,032**	**$123,547,523**	**$142,993,530**

Exhibit A-4: Impact of Storage on Supply Costs

	New England Pricing	Marcellus Pricing	Mixed Supply
2017/18	-$13,778,301	-$32,023,647	-$13,778,301
2018/19	-$15,668,229	-$32,981,147	-$15,668,229
2019/20	-$19,923,212	-$34,121,591	-$19,923,212
2020/21	-$15,598,795	-$33,839,917	-$15,598,795
2021/22	-$17,211,502	-$34,362,482	-$17,211,502
2022/23	-$18,677,970	-$35,048,582	-$18,677,970
2023/24	-$19,780,386	-$35,841,409	-$19,651,141
2024/25	-$17,084,152	-$36,236,798	-$17,084,152
2025/26	-$16,383,615	-$37,529,691	-$16,383,615
2026/27	-$21,646,794	-$38,506,164	-$21,522,111
2027/28	-$17,830,804	-$38,127,264	-$17,830,804
2028/29	-$24,898,044	-$38,658,514	-$23,841,300
2029/30	-$25,975,406	-$39,395,267	-$24,252,302
2030/31	-$19,581,627	-$39,200,458	-$19,581,627
2031/32	-$20,298,459	-$40,505,891	-$20,298,459
2032/33	-$23,633,130	-$41,059,163	-$22,252,838
2033/34	-$31,614,310	-$42,205,282	-$25,708,015
2034/35	-$21,084,104	-$42,041,927	-$20,763,742
Averages:			
2017/18 - 2021/22	(16,436,008)	(33,465,757)	(16,436,008)
2022/23 - 2026/27	(18,714,583)	(36,632,529)	(18,663,798)
2027/28 - 2031/32	(21,716,868)	(39,177,479)	(21,160,898)
2017/18 - 2034/35	**-$20,037,158**	**-$37,315,844**	**-$19,446,006**

Exhibit A-5: Heritage Demand Profile (GJ/d)

Month	Average	Design Day	Min	Max
Apr-17	29,104	71,298	25,904	29,798
May-17	21,345	71,298	19,266	21,816
Jun-17	16,787	71,298	15,405	17,136
Jul-17	13,841	71,298	12,441	14,194
Aug-17	13,664	71,298	12,609	14,020
Sep-17	15,535	71,298	13,259	16,024
Oct-17	21,194	71,298	18,135	21,931
Nov-17	29,883	71,298	25,352	30,903
Dec-17	38,296	71,298	34,255	39,326
Jan-18	44,851	71,298	40,879	45,884
Feb-18	47,019	71,298	43,139	48,054
Mar-18	39,514	71,298	34,749	40,551
Apr-18	29,795	72,773	26,889	30,499
May-18	21,773	72,773	19,542	22,246
Jun-18	17,065	72,773	15,613	17,414
Jul-18	14,018	72,773	12,404	14,367
Aug-18	13,827	72,773	12,223	14,177
Sep-18	15,702	72,773	13,600	16,179
Oct-18	21,493	72,773	19,285	22,206
Nov-18	30,357	72,773	26,487	31,335
Dec-18	38,899	72,773	34,532	39,879
Jan-19	45,574	72,773	41,586	46,556
Feb-19	47,771	72,773	44,179	48,755
Mar-19	40,098	72,773	35,459	41,084
Apr-19	30,183	73,848	26,992	30,897
May-19	22,000	73,848	19,835	22,480
Jun-19	17,208	73,848	15,877	17,562
Jul-19	14,101	73,848	12,538	14,455
Aug-19	13,898	73,848	12,541	14,253
Sep-19	15,806	73,848	13,649	16,290
Oct-19	21,831	73,848	19,121	22,554
Nov-19	30,940	73,848	26,497	31,932
Dec-19	39,845	73,848	35,955	40,839
Jan-20	46,707	73,848	42,741	47,704
Feb-20	47,292	73,848	44,281	48,291
Mar-20	41,062	73,848	37,290	42,063
Apr-20	30,857	75,430	27,588	31,586
May-20	22,442	75,430	20,155	22,932

Jun-20	17,499	75,430	15,828	17,860
Jul-20	14,285	75,430	12,897	14,647
Aug-20	14,076	75,430	13,502	14,438
Sep-20	16,033	75,430	13,941	16,527
Oct-20	22,247	75,430	19,027	22,985
Nov-20	31,590	75,430	27,013	32,604
Dec-20	40,755	75,430	37,713	41,771
Jan-21	47,796	75,430	43,204	48,814
Feb-21	50,143	75,430	46,199	51,163
Mar-21	41,991	75,430	37,663	43,013
Apr-21	31,509	76,987	28,331	32,253
May-21	22,871	76,987	20,607	23,371
Jun-21	17,782	76,987	16,250	18,150
Jul-21	14,464	76,987	12,758	14,833
Aug-21	14,249	76,987	12,592	14,619
Sep-21	16,265	76,987	13,960	16,769
Oct-21	22,674	76,987	19,504	23,427
Nov-21	32,260	76,987	28,241	33,294
Dec-21	41,696	76,987	38,518	42,732
Jan-22	48,924	76,987	44,175	49,963
Feb-22	51,348	76,987	46,489	52,389
Mar-22	42,951	76,987	38,103	43,994
Apr-22	32,180	78,564	28,791	32,940
May-22	23,311	78,564	20,998	23,821
Jun-22	18,071	78,564	16,299	18,447
Jul-22	14,647	78,564	13,006	15,023
Aug-22	14,426	78,564	12,662	14,804
Sep-22	16,492	78,564	14,914	17,007
Oct-22	23,090	78,564	19,870	23,859
Nov-22	32,910	78,564	27,970	33,966
Dec-22	42,606	78,564	38,821	43,664
Jan-23	50,012	78,564	45,731	51,073
Feb-23	52,510	78,564	47,663	53,572
Mar-23	43,879	78,564	40,104	44,944
Apr-23	32,832	80,107	29,188	33,606
May-23	23,740	80,107	21,539	24,260
Jun-23	18,354	80,107	16,763	18,737
Jul-23	14,826	80,107	13,124	15,210
Aug-23	14,599	80,107	12,805	14,984
Sep-23	16,719	80,107	14,294	17,244
Oct-23	23,506	80,107	20,554	24,290

Nov-23	33,560	80,107	28,501	34,637
Dec-23	43,515	80,107	38,981	44,594
Jan-24	51,101	80,107	46,933	52,182
Feb-24	51,821	80,107	47,087	52,905
Mar-24	44,808	80,107	40,803	45,894
Apr-24	33,483	81,650	29,826	34,273
May-24	24,169	81,650	22,050	24,699
Jun-24	18,637	81,650	17,073	19,028
Jul-24	15,005	81,650	13,470	15,397
Aug-24	14,773	81,650	12,932	15,165
Sep-24	16,946	81,650	15,133	17,481
Oct-24	23,922	81,650	20,593	24,721
Nov-24	34,210	81,650	29,336	35,308
Dec-24	44,425	81,650	40,096	45,525
Jan-25	52,189	81,650	47,952	53,291
Feb-25	54,835	81,650	49,751	55,939
Mar-25	45,736	81,650	40,854	46,843
Apr-25	34,135	83,193	30,814	34,939
May-25	24,597	83,193	22,048	25,138
Jun-25	18,920	83,193	17,620	19,318
Jul-25	15,184	83,193	13,339	15,583
Aug-25	14,946	83,193	13,112	15,346
Sep-25	17,173	83,193	14,772	17,718
Oct-25	24,338	83,193	21,815	25,153
Nov-25	34,861	83,193	30,318	35,979
Dec-25	45,335	83,193	40,345	46,456
Jan-26	52,962	83,193	48,558	54,085
Feb-26	55,607	83,193	50,307	56,732
Mar-26	46,468	83,193	41,673	47,596
Apr-26	34,770	84,839	31,106	35,590
May-26	25,142	84,839	22,655	25,693
Jun-26	19,439	84,839	17,909	19,845
Jul-26	15,702	84,839	13,906	16,109
Aug-26	15,462	84,839	13,904	15,870
Sep-26	17,708	84,839	15,231	18,264
Oct-26	24,896	84,839	21,785	25,727
Nov-26	35,545	84,839	30,444	36,686
Dec-26	46,090	84,839	41,623	47,232
Jan-27	54,010	84,839	49,456	55,155
Feb-27	56,708	84,839	53,249	57,855
Mar-27	47,388	84,839	43,055	48,538

Apr-27	35,458	86,517	31,710	36,294
May-27	25,639	86,517	23,017	26,201
Jun-27	19,823	86,517	17,908	20,237
Jul-27	16,013	86,517	14,422	16,428
Aug-27	15,768	86,517	14,004	16,184
Sep-27	18,058	86,517	16,001	18,625
Oct-27	25,389	86,517	21,697	26,236
Nov-27	36,249	86,517	31,001	37,411
Dec-27	47,002	86,517	43,515	48,167
Jan-28	55,079	86,517	49,814	56,247
Feb-28	55,835	86,517	52,284	57,005
Mar-28	48,325	86,517	43,364	49,498
Apr-28	36,159	88,229	32,519	37,012
May-28	26,146	88,229	23,553	26,720
Jun-28	20,215	88,229	18,461	20,638
Jul-28	16,329	88,229	14,376	16,752
Aug-28	16,080	88,229	14,181	16,504
Sep-28	18,415	88,229	15,775	18,993
Oct-28	25,891	88,229	22,260	26,755
Nov-28	36,966	88,229	32,363	38,152
Dec-28	47,931	88,229	43,254	49,120
Jan-29	56,169	88,229	50,602	57,359
Feb-29	58,974	88,229	53,426	60,167
Mar-29	49,281	88,229	43,727	50,477
Apr-29	36,874	89,974	32,995	37,744
May-29	26,664	89,974	24,017	27,248
Jun-29	20,615	89,974	18,587	21,046
Jul-29	16,652	89,974	14,774	17,084
Aug-29	16,398	89,974	14,379	16,831
Sep-29	18,780	89,974	16,974	19,369
Oct-29	26,404	89,974	22,276	27,284
Nov-29	37,697	89,974	32,582	38,906
Dec-29	48,880	89,974	44,547	50,092
Jan-30	57,280	89,974	52,379	58,494
Feb-30	60,140	89,974	54,592	61,357
Mar-30	50,256	89,974	46,048	51,476
Apr-30	37,604	91,755	33,433	38,491
May-30	27,191	91,755	24,868	27,787
Jun-30	21,023	91,755	19,202	21,462
Jul-30	16,982	91,755	15,034	17,422
Aug-30	16,722	91,755	14,669	17,164

Sep-30	19,151	91,755	16,375	19,752
Oct-30	26,926	91,755	23,508	27,824
Nov-30	38,443	91,755	32,650	39,676
Dec-30	49,847	91,755	45,455	51,082
Jan-31	58,413	91,755	53,641	59,651
Feb-31	61,330	91,755	55,910	62,571
Mar-31	51,251	91,755	45,480	52,494
Apr-31	38,348	93,570	34,316	39,253
May-31	27,729	93,570	25,302	28,337
Jun-31	21,439	93,570	19,648	21,887
Jul-31	17,318	93,570	15,560	17,767
Aug-31	17,053	93,570	14,945	17,503
Sep-31	19,530	93,570	17,963	20,143
Oct-31	27,459	93,570	23,645	28,375
Nov-31	39,204	93,570	33,620	40,461
Dec-31	50,833	93,570	45,874	52,093
Jan-32	59,569	93,570	54,714	60,831
Feb-32	60,387	93,570	54,564	61,652
Mar-32	52,265	93,570	46,671	53,533
Apr-32	39,107	95,421	35,355	40,029
May-32	28,278	95,421	25,355	28,898
Jun-32	21,863	95,421	20,373	22,320
Jul-32	17,660	95,421	15,546	18,118
Aug-32	17,391	95,421	15,937	17,850
Sep-32	19,917	95,421	17,164	20,542
Oct-32	28,002	95,421	25,976	28,936
Nov-32	39,979	95,421	34,739	41,262
Dec-32	51,839	95,421	46,117	53,124
Jan-33	60,747	95,421	55,698	62,035
Feb-33	63,781	95,421	57,704	65,071
Mar-33	53,299	95,421	47,800	54,592
Apr-33	39,880	97,309	35,680	40,821
May-33	28,837	97,309	25,986	29,469
Jun-33	22,296	97,309	20,688	22,762
Jul-33	18,010	97,309	15,951	18,477
Aug-33	17,735	97,309	15,646	18,203
Sep-33	20,311	97,309	17,586	20,948
Oct-33	28,556	97,309	24,286	29,509
Nov-33	40,770	97,309	35,602	42,078
Dec-33	52,864	97,309	47,743	54,175
Jan-34	61,949	97,309	56,728	63,262

Feb-34	65,043	97,309	61,087	66,359
Mar-34	54,353	97,309	48,928	55,672
Apr-34	40,669	99,234	36,373	41,629
May-34	29,408	99,234	26,402	30,052
Jun-34	22,737	99,234	20,541	23,212
Jul-34	18,366	99,234	16,542	18,842
Aug-34	18,086	99,234	16,064	18,563
Sep-34	20,712	99,234	18,354	21,363
Oct-34	29,121	99,234	24,888	30,092
Nov-34	41,577	99,234	35,560	42,911
Dec-34	53,910	99,234	48,629	55,247
Jan-35	63,175	99,234	57,138	64,514
Feb-35	66,330	99,234	60,641	67,671
Mar-35	55,429	99,234	50,786	56,773

Exhibit A-6. Withdrawal and Injection Rates from Storage (GJ/d)

	New England Supply	Marcellus Supply	Mixed Supply
2017/18	[redacted]		
2018/19			
2019/20			
2020/21			
2021/22			
2022/23			
2023/24			
2024/25			
2025/26			
2026/27			
2027/28			
2028/29			
2029/30			
2030/31			
2031/32			
2032/33			
2033/34			
2034/35			
2017/18 - 2021/22	[redacted]		
2022/23 - 2026/27			
2027/28 - 2031/32			
2017/18 - 2034/35	[redacted]		
	Injection Averages		

2017/18 - 2021/22	[redacted]	[redacted]	[redacted]
2022/23 - 2026/27	[redacted]	[redacted]	[redacted]
2027/28 - 2031/32	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
2017/18 - 2034/35	[redacted]	[redacted]	[redacted]

Exhibit A-7: Average Impact of Weather on Optimized Alton Storage Capacity (GJ)

	New England Supply	Marcellus Supply	Mixed Supply
Normal Cases			
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
Impact of Weather Volatility on Storage Requirements			
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]

Exhibit A-8: Annual Average Total Portfolio Costs with Higher Deliverability

Heritage Gas Portfolio Supply Cost: New England Supply

	Alton Deliverability	25% Higher Deliverability	50% Higher Deliverability	75% Higher Deliverability	100% Higher Deliverability
2017/18	$81,045,188	$79,411,203	$77,961,926	$77,280,579	$77,063,384
2018/19	$80,895,304	$79,207,131	$77,590,274	$76,740,554	$76,491,826
2019/20	$87,811,955	$86,055,235	$84,358,935	$83,463,545	$83,314,322
2020/21	$98,445,916	$96,659,865	$94,801,592	$93,747,398	$93,301,985
2021/22	$97,423,978	$95,601,869	$93,741,737	$92,672,466	$92,375,066
2022/23	$99,173,307	$97,309,874	$95,483,415	$94,485,562	$94,185,866
2023/24	$104,616,990	$102,689,661	$100,762,170	$99,681,336	$99,242,059
2024/25	$110,124,731	$108,162,374	$106,119,378	$104,705,453	$104,130,856
2025/26	$109,366,434	$107,381,944	$105,353,904	$104,045,024	$103,300,712
2026/27	$123,700,689	$121,648,215	$119,607,686	$118,165,749	$117,583,059
2027/28	$130,578,831	$128,486,036	$126,362,110	$125,122,285	$124,590,129
2028/29	$134,419,939	$132,232,858	$129,939,290	$128,679,327	$128,312,401
2029/30	$143,567,660	$141,296,594	$138,888,016	$137,149,222	$136,578,509
2030/31	$149,916,649	$147,682,034	$145,340,761	$143,620,424	$142,700,304
2031/32	$155,147,434	$152,858,602	$150,433,714	$148,616,315	$147,697,167
2032/33	$163,429,554	$161,089,136	$158,538,386	$156,488,540	$155,664,646
2033/34	$175,181,897	$172,500,740	$169,668,064	$167,787,280	$167,277,360
2034/35	$179,008,962	$176,576,878	$173,996,531	$171,675,316	$170,338,645
2017/18 - 2021/22	$89,124,468	$87,387,061	$85,690,893	$84,780,909	$84,509,317
2022/23 - 2026/27	$109,396,430	$107,438,414	$105,465,311	$104,216,625	$103,688,511
2027/28 - 2031/32	$142,726,103	$140,511,225	$138,192,778	$136,637,514	$135,975,702
2017/18 - 2034/35	$123,547,523	$121,491,681	$119,385,994	$118,007,021	$117,452,683
Benefit over Alton		$2,055,843	$4,161,529	$5,540,502	$6,094,840

Heritage Gas Portfolio Supply Cost: Marcellus Supply

	Alton Deliverability	25% Higher Deliverability	50% Higher Deliverability	75% Higher Deliverability	100% Higher Deliverability
2017/18	$95,439,859	$93,600,814	$91,685,540	$89,770,265	$87,854,990
2018/19	$96,397,673	$94,521,855	$92,568,283	$90,614,711	$88,661,140
2019/20	$103,530,939	$101,598,669	$99,586,304	$97,573,939	$95,561,574
2020/21	$114,235,754	$112,239,149	$110,159,783	$108,080,417	$106,001,050
2021/22	$112,563,565	$110,520,170	$108,392,075	$106,263,980	$104,135,885
2022/23	$114,725,490	$112,644,510	$110,477,271	$108,310,032	$106,142,794
2023/24	$119,299,203	$117,163,720	$114,939,719	$112,715,718	$110,491,718
2024/25	$126,788,677	$124,594,744	$122,309,869	$120,024,995	$117,740,121
2025/26	$127,119,533	$124,880,535	$122,548,729	$120,216,922	$117,885,116
2026/27	$141,223,104	$138,844,696	$136,367,702	$133,890,707	$131,413,712
2027/28	$148,914,365	$146,510,262	$144,006,506	$141,502,751	$138,998,995
2028/29	$151,248,916	$148,818,024	$146,286,370	$143,754,716	$141,223,061
2029/30	$161,155,455	$158,621,700	$155,982,919	$153,344,138	$150,705,357
2030/31	$170,148,141	$167,576,900	$164,899,080	$162,221,260	$159,543,440
2031/32	$175,367,646	$172,698,399	$169,918,509	$167,138,619	$164,358,729
2032/33	$181,956,004	$179,232,562	$176,396,230	$173,559,898	$170,723,567
2033/34	$194,346,861	$191,535,185	$188,606,963	$185,678,741	$182,750,518
2034/35	$200,284,203	$197,430,040	$194,457,570	$191,485,100	$188,512,630
2017/18 - 2021/22	$104,433,558	$102,496,131	$100,478,397	$98,460,662	$96,442,928
2022/23 - 2026/27	$125,831,201	$123,625,641	$121,328,658	$119,031,675	$116,734,692
2027/28 - 2031/32	$161,366,905	$158,845,057	$156,218,677	$153,592,297	$150,965,916
2017/18 - 2034/35	$140,819,188	$138,501,774	$136,088,301	$133,674,828	$131,261,355
Benefit over Alton		$2,317,414	$4,730,887	$7,144,360	$9,557,833

Attachment 2.

ICF Sensitivity Analysis: "Opinion Regarding Alton Storage

(Dated September 9, 2014)

Attachment 2

MEMORANDUM

To: Michael Johnston, Heritage Gas

From: ICF International

Date: September 9, 2014

Subject: Opinion Regarding Alton Storage Offer [redacted]

This memo is in response to your request today.

Since ICF submitted our July 18 report to Heritage Gas, entitled "Updated Assessment of Alton Natural Gas Storage," Heritage has been in negotiations with Alton over its storage offering. Where our analysis focused on finding the optimal level of storage capacity subject to a variety of constraints, including expected gas demand, gas prices, and gas pipeline costs, Alton's present offer is capped at [redacted] GJs of storage capacity, or Maximum Customer Inventory (MCI). Alton also would retain the same withdrawal and injection ratios, yielding a maximum withdrawal rate of [redacted] and maximum injection rate of [redacted]

Our July analysis had found that a higher level of MCI would help Heritage better optimize your gas portfolio, including gas pipeline capacity purchases, along with correspondingly higher levels of injection and withdrawal at Alton's proposed injection and withdrawal ratios. With the MCI cap now offered by Alton, the issue is whether, at this level of MCI, Alton's the storage offer would still generate benefits for Heritage and your customers.

ICF has re-run its storage model to recalculate the benefits of storage using the capped MCI offered by Alton. All other elements of the model calculations were kept the same, i.e., demand, design-day, pipeline costs, storage costs, gas prices and volatility, etc. Our results are shown in the table below.

Averages:	New England Supply w/ [redacted] GJ Storage	New England Supply w/o Storage	Marcellus Supply w/ [redacted] GJ Storage	Marcellus Supply w/o Storage	Mixed Supply w/ [redacted] GJ Storage	Mixed Supply w/o Storage
2017/18 - 2021/22	$90,011,831	$105,560,476	$110,805,504	$137,899,315	$90,011,831	$105,560,476
2022/23 - 2026/27	$111,345,337	$128,111,014	$135,280,906	$162,463,730	$111,345,337	$128,060,228
2027/28 - 2031/32	$146,084,309	$164,442,971	$173,881,556	$200,544,383	$146,005,659	$163,887,001
2017/18 - 2034/35	$126,065,012	$143,584,681	$151,175,092	$178,135,032	$125,941,807	$142,993,530
Savings	$17,519,669		$26,959,940		$17,051,723	

In our calculations, the [redacted] cap on storage capacity now offered by Alton still produces benefits for Heritage and your customers relative to not contracting for storage. The savings are somewhat lower than they would be if you could contract for an optimal level of storage. This is to be expected. Heritage will have to buy a higher level of gas pipeline capacity since the withdrawal rate from storage, [redacted] is lower than our optimized storage analysis estimated. Buying the additional pipeline capacity reduces the benefits. The effect of the higher level of pipeline capacity is most pronounced under the Marcellus option. In addition, with the lower level of MCI, Heritage also would have less ability to fully capture the swings in gas prices for the gas destined for storage.

Accompanying this memo is the spreadsheet with the annual costs used to calculate the table above. We also show the new levels of pipeline capacity required under the capped storage offer.

In our opinion, the present Alton offer of storage as articulated above would reduce your gas purchase costs relative to not having storage and would provide substantial benefits to Heritage and your customers.

Attachment 3.
ICF Sensitivity Analysis:
“Reduced Seasonal Gas Price Spreads”
(Dated September 18, 2014)

MEMORANDUM

To: Michael Johnston, Heritage Gas

From: ICF International

Date: September 18, 2014

Subject: Additional Model Run Results, Reduced Seasonal Gas Price Spreads

Earlier this week Heritage requested ICF to evaluate the benefits of storage under alternative assumptions. These include:

> What would be the benefits of storage were New England gas prices to see a collapse in their historical seasonal price basis; i.e., if the price spread between winter and summer were to diminish?

We present our results below.

ICF ran two sets of cases. The first set of cases eliminates entirely the winter summer price spread and presents to the model a flat annual price for gas in all years. The second set of cases are based on a normal monthly price series for New England but without the daily volatility. This eliminates the daily winter price spikes seen in New England prices (as well as daily low price troughs at other times). Each month has relatively flat prices within the month, where the winter months have higher averages than summer months. This pattern comes out of the ICF Gas Market Model (GMM) forecast.

Exhibit A. Gas Supply Costs and Benefits of Storage at Flat and Moderated Seasonal Gas Prices in New England

	Storage Capped at [redacted]		No Storage	
Averages:	New England Supply w/ Flat Annual Prices	New England Supply w/Monthly Average Prices	w/Flat Annual Prices	w/Monthly Average Prices
2017/18 - 2021/22	$98,514,494	$95,430,135	$100,703,358	$108,197,280
2022/23 - 2026/27	$121,157,557	$118,828,256	$123,062,729	$131,863,454
2027/28 - 2031/32	$157,119,817	$156,128,376	$158,613,074	$168,979,538
2017/18 - 2034/35	$136,315,462	$134,454,880	$138,064,151	$147,456,197
Savings	$1,748,689	$13,001,316		

Exhibit A shows that at flat prices, the value of storage is still positive but considerably smaller than when prices follow normal seasonal patterns. The savings here arise from optimized pipeline capacity. Storage allows you to reduce pipeline capacity relative to the no storage option.

Taking out the volatility in gas prices but keeping the monthly average prices forecast in ICF's GMM still generates substantial benefits, as we would expect. Any further reduction in seasonality from the

Monthly Average Price Scenario, would reduce savings, and the benefits would fall to somewhere between the Flat Annual Case and the Monthly Average Case.

Attachment 4.
Navigant: Cost-of-Service and
Pricing Recommendations for the Alton Natural Gas Storage Field Service Costs
(Dated December 4, 2014)

Cost-of-Service and Pricing Recommendations for the Alton Natural Gas Storage Field Service Costs

Prepared for:
Heritage Gas Limited

Navigant Consulting, Ltd.
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Toronto, Ontario

312.583.4167
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Navigant Project No. 171451
December 4, 2014

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1. Executive Summary

Navigant Consulting, Ltd ("Navigant") has been retained by Heritage Gas Limited ("Heritage Gas") to develop a cost allocation and pricing design for the proposed Alton Natural Gas Storage Facility ("Alton Facility"). The Alton Facility is planned to be a 4-6 Billion Cubic Feet ("BCF") storage field located near Stewiacke (Alton), Nova Scotia. The proposed site is located on the Maritimes and North East Pipeline ("M&NP") Halifax lateral, roughly 60 kilometers from Heritage Gas' largest market in the Halifax Regional Municipality. Currently there are no underground gas storage facilities north of Boston along the M&NP route. Significant price volatility exists during peak load time periods when extreme price spikes occur.

The Alton Facility is owned by AltaGas Ltd. Heritage Gas is a wholly-owned subsidiary of AltaGas Utility Group Inc. which in turn is a wholly-owned subsidiary of AltaGas Ltd. Navigant has reviewed Heritage Gas' Inter-Affiliate Code of Conduct when preparing our proposed cost allocation and pricing design. The proposed cost recovery, allocation and pricing design detailed in this report follows the Heritage Gas' Inter-Affiliate Code of Conduct.

The basis of the proposed cost of the Alton Facility to Heritage Gas is the proposed contract between the two parties. The pricing elements detailed in the contract form the basis of the input costs in the cost allocation methodology. In contrast, if the Alton Facility had been incorporated as an asset within Heritage Gas, a traditional cost of service by account would have been performed.

Storage services have been defined as three functions. The first function captures the charges detailed in the contract for the Alton Facility. Secondly, cushion gas will be required in order to make the facility operational which will be a separate function in the cost of service study. The last function will be "Natural Gas in Storage". Heritage Gas will be provided a return for the working capital associated with the natural gas inventory stored at the Alton Facility.

Navigant recommends that the costs of the Alton Facility be classified using the "Equitable Method". The Equitable Method is recognized as the appropriate approach to cost allocation for natural gas storage by the United States Federal Energy Regulatory Commission ("FERC") and is used in the industry.

Navigant recommends that the allocation of the storage field costs be performed on a seasonal volumetric basis. The seasonal volumetric basis allocates costs to each tariff class based upon consumption during the withdrawal season where the Alton Facility is typically providing service to the system.

Navigant evaluated the results of the cost allocation using a Benefit Cost Analysis ("BCA") estimating the impact of the cost allocation on each tariff class versus the benefit each tariff class would receive. The results of the BCA indicate that each tariff class would experience a net benefit.

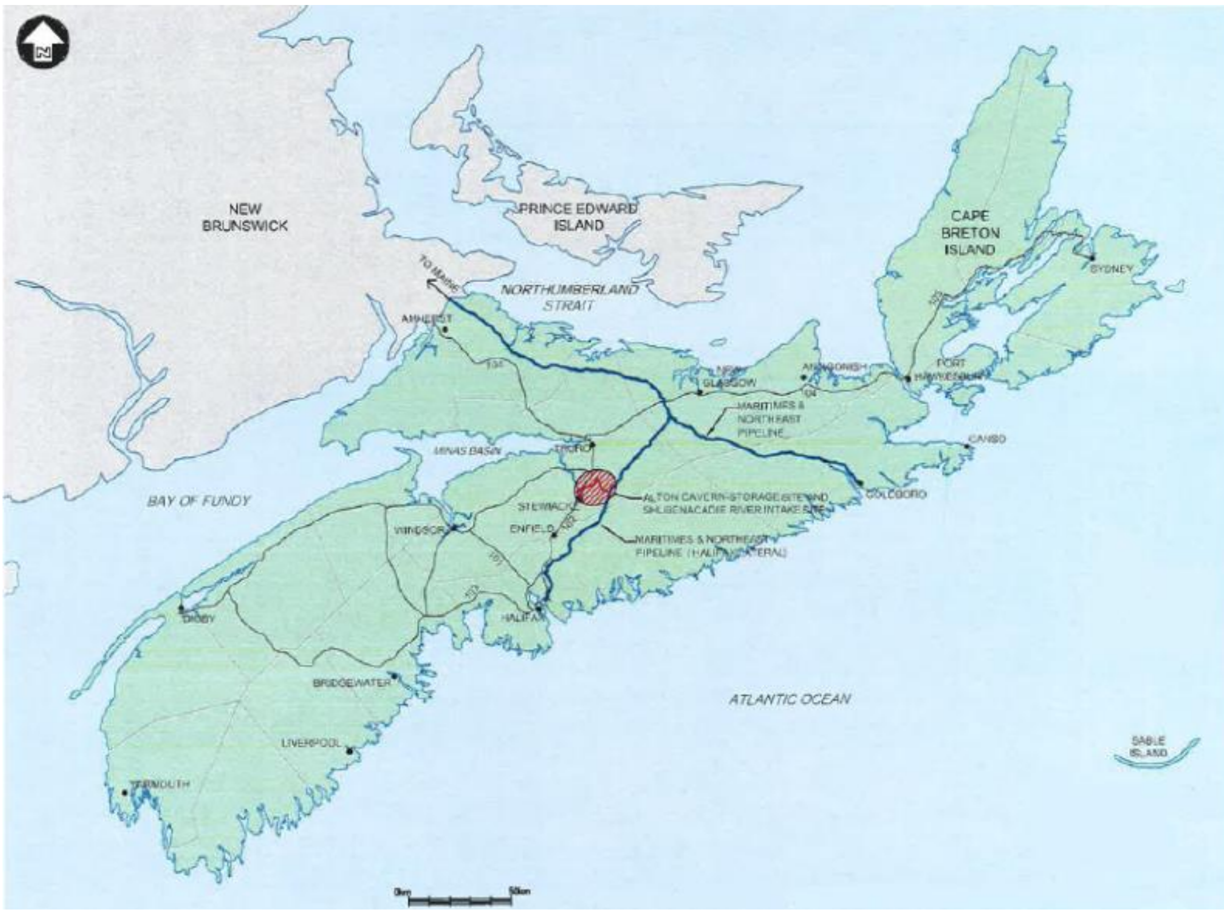
In developing the pricing proposal for storage field services Navigant relied upon: (1) the existing cost allocation practices before the Nova Scotia Utility and Review Board ("Board"); (2) a recognition that the services for the Alton Facility will be used by both system supply and self supply customers; and (3) the usage of the field is uncertain and future billing determinants are difficult to estimate at this time.

Therefore, Navigant proposes a reconciling clause is developed for the costs associated with the Alton Facility providing protection to both Heritage Gas and its customers for over- and under-recovery of the contractual costs associated with Alton Facility costs.

2. Description of the Alton Natural Gas Storage Field

The proposed Alton Facility involves the construction and operation of a planned 4-6 BCF[1] natural gas storage facility in Colchester County, Nova Scotia ("the Province"). The Province currently has no facility able to store natural gas. The facility will consist of several naturally occurring solution-mined caverns to be brined out of a large, structurally stable salt formation. Figure 1 below details the proposed location of the Alton Facility.

Figure 1 – Proposed Location of Alton Natural Gas Storage Field



Source: Application for Approval to Construct Alton Natural Gas Storage Cavern Development, SolTech Projects, June, 2011

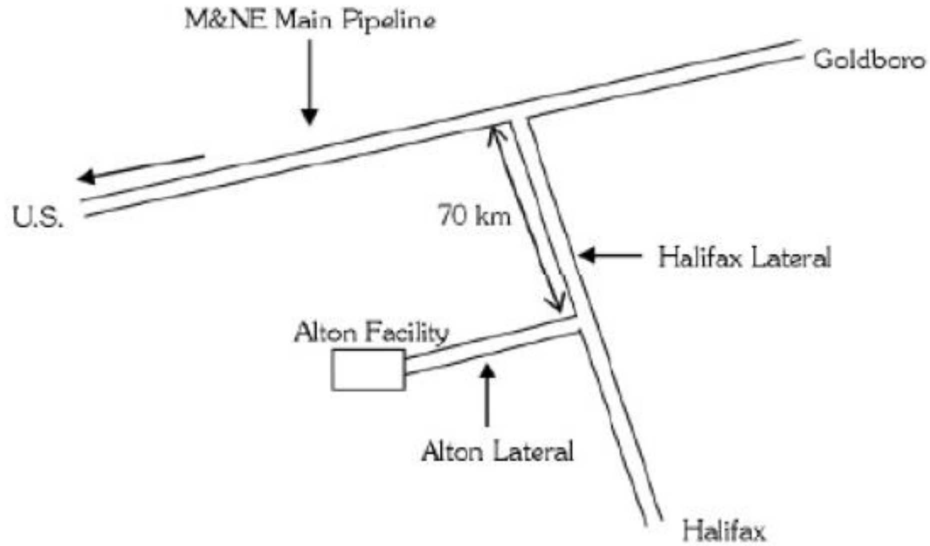
The gas injected into the Alton Facility will be transported on the M&NP. The M&NP is a 1,440 km (895 mi), 762 mm (30 in) gas transmission line that transports natural gas from Goldboro, Nova Scotia to the U.S. - Canada border in Maine, terminating in Beverly, Massachusetts.

Figure 2 below illustrates the pipeline network linking the Alton Facility to the M&NP pipeline. The gas from the M&NP pipeline flows through the 324 mm (12 in) M&NP Halifax lateral that is 124 km (77 mi) in length. The proposed Alton Facility interconnecting pipeline is a 406 mm (16 in) line will be 10 km (6.2 mi) long. During withdrawal from the cavern, a portion of the total gas flowing through the Alton

[1] The proposed Alton Facility has the capability to be expanded to 20 BCF in the future.

Facility lateral will serve the Halifax market and the remainder will flow through the 70 km (44 mi) north section of the Halifax lateral to the M&NP pipeline.

Figure 2 – Interconnection of the Alton Storage Field to Heritage Gas



Source: Application for Approval to Construct Alton Natural Gas Storage Cavern Development, SolTech Projects, June, 2011

3. The Alton Facility Contract Pricing Design

The Alton Facility is planning to offer two types of storage services: Firm Storage Service ("FSS") and Short Term Storage Service ("STSS"); to Heritage Gas and other customers. Navigant has assumed for the purposes of this report that Heritage Gas will only contract for FSS.

Navigant has also assumed that the charges from the Alton Facility are based upon an arm's length transaction and represent an expense to be recovered in the revenue requirement of the utility. Further, the cost allocation and pricing design for storage services will be directly linked to the pricing design of the proposed contract between the Alton Facility and Heritage Gas. A summary of the pricing provisions are provided below.

3.1 Firm Storage Service

Firm Storage Service will contain the following pricing components.

Injection Commodity

An Injection Commodity Rate ("ICR") of [redacted] per Gigajoule ("GJ") will be charged to Heritage Gas based upon the quantity of natural gas delivered to the Alton Facility. Expenses associated with fuel gas used for compressors at the storage facility are assumed to be 2% of the Maximum Customer Inventory ([redacted] at the summer market commodity price.

Withdrawal Commodity

A Withdrawal Commodity Rate ("WCR") of [redacted] per GJ will be charged to Heritage Gas based upon the quantity of natural gas withdrawn by or on behalf of Heritage Gas from the Alton Facility.

Inventory Demand

The Inventory Demand Rate ("IDR") is based on the Target Project Cost and Initial Project Target Capacity, IDR is [redacted] ("Target IDR"), subject to adjustment as follows:

1. <u>If Unitized Actual Construction Cost > Unitized Target Construction Cost</u>:

   *IDR increase = Target IDR * ((A-T)/ T)*

2. <u>If Unitized Actual Construction Cost < Unitized Target Construction Cost</u>:

   *IDR reduction = Target IDR * ((A-T)/ T)*

where

A = Unitized Actual Construction Cost, which equals actual construction cost divided by the lesser of (i) Actual Capacity or (ii) Initial Project Target Capacity

T = Unitized Target Construction Cost, which equals Target Construction Cost divided by Initial Project Target Capacity

The sum of the Injection Charge, the Withdrawal Charge and the Inventory Demand Charge are applicable to the Billing Month.

Other Fees

All other fees, charges, damages, and other amounts payable in accordance with the Alton Tariff for that Gas Month, or as specified on the FSS Transaction Form.

3.2 Short Term Storage Service

Navigant has assumed that Heritage Gas will only receive FSS from the Alton Facility.

4. Development of the Indicative Functional Revenue Requirement

In order to illustrate the cost of service and pricing design framework, Navigant developed an indicative revenue requirement for natural gas storage field services. Navigant is labeling the revenue requirement as indicative because the final costs of the Alton Facility will not be known until after construction is completed.

The indicative revenue requirement separates the cost of storage into three distinct functions. The first function captures all charges associated with the Alton Facility contract. The second function includes the costs associated with the Cushion Gas. The third function includes the costs associated with the Natural Gas in Storage.

4.1 Alton Storage Field Charges

The charges for the Alton Facility will be treated as expenses and will be adopted based upon the contract that will be executed between the Alton Facility and Heritage Gas. A summary of the charges used to develop the indicative annual revenue requirement is provided in Table 1 below.

Table 1 – Assumed Pricing of Contract Components

Pricing Component	Unit	Charge
Inventory Demand Rate (IDR)	$/GJ/ month	[redacted]
Injection Commodity Rate (ICR)	$/GJ	[redacted]
Withdrawal Commodity Rate (WCR)	$/GJ	[redacted]
Fuel Cost Associated with Injections		2% of MCI @ Market Price

Source: Alton Storage Agreement with Heritage Gas

Navigant has further assumed a Maximum Customer Inventory ("MCI") of [redacted] and that injections/withdrawals over an annual time period can be no more than [redacted] Expenses associated with injections also include cost estimations for fuel gas used for compressors at the Alton Facility.

Table 2 below provides a summary of the revenue requirement associated with the Alton Facility contract charges.

[2] Based upon full utilization of storage facility ([redacted]

Table 2 – Summary of Revenue Requirement for the Alton Facility Contract Charges

Component	Amount
Inventory Demand Charges[3]	[redacted]
Expenses Associated With Injections	[redacted]
Expenses Associated With Withdrawals[4]	[redacted]
Total Revenue Requirement for Alton Facility	[redacted]

Source: Appendix B

Table 3 – Development of Injection Expenses

Component	Unit	ICR	Fuel Gas	Amount
Maximum Customer Inventory (MCI)	GJ	[redacted]	[redacted]	
Injection Commodity Rate (ICR)	$/GJ	[redacted]		
Fuel Used for Compressors	%		2%	
	GJ		[redacted]	
Estimated Cost of Natural Gas in Storage (Rounded)	$/GJ		$4.25	
Total Expenses Associated With Injections		[redacted]	[redacted]	[redacted]

4.2 Cost of Cushion Gas

Navigant has assumed that the Cushion Gas will be purchased by Heritage Gas and injected into the Alton Facility. Therefore, Navigant recommends that the Cushion Gas will become part of Heritage Gas' rate base. The cost of the Cushion Gas was estimated based upon historical natural gas market price data[5] for the Algonquin City-Gates delivery point for the period May 1 through September 30, 2013. The average price for that time period was $4.25/GJ (rounded). Further, Navigant assumed that [redacted] of Cushion Gas would be required resulting in a cost of Cushion Gas of [redacted] which was added to rate base. The [redacted] of Cushion Gas was derived based upon 25% of the MCI.

4.3 Natural Gas in Storage

The final function in the revenue requirement is natural gas in storage which will provide Heritage with a mechanism to recover a return associated with the average natural gas inventory. Navigant has assumed that [redacted] would be in storage at an average price of $4.25/GJ. All assumptions regarding return and taxes are identical to those employed in the cushion gas analysis.

4.4 Income Tax and Cost of Capital Assumptions

Federal and Provincial Tax Assumptions

Navigant assumed a Nova Scotia Provincial income tax rate of 16% and a Canadian Federal income tax rate of 15%.

[3] MCI of [redacted]
[4] Withdrawals of [redacted]
[5] Data for Algonquin City-Gates delivery point based on SNL Spot Natural Gas Index
[6] [redacted]

Cost of Capital

Navigant used a cost of capital and capital structure adopted from Heritage Gas' last General Tariff Application proceeding resulting in a Weighted Average Cost of Capital (WACC) of 8.9375%[7].

4.5 Results of the Indicative Revenue Requirement Analysis

Based upon the above assumptions Navigant has prepared the following first year indicative revenue requirement associated with the Alton Facility, Cushion Gas and Natural Gas in Storage summarized in Table 4 below.

Table 4 – Indicative Revenue Requirement for the Alton Facility Cushion Gas and Natural Gas in Storage

Component	Amount
Total Rev. Req. for Alton Storage Facility	[redacted]
Total Rev. Req. for Cushion Gas	[redacted]
Total Rev. Req. for Natural Gas in Storage	[redacted]
Total Revenue Requirement	$14,041,509

Source: Appendix C

[7] The WACC pretax and is based upon Heritage Gas 2011 General Tariff Application

5. Approach to Classification of Costs

In the previous chapter Navigant developed three functions associated with the Alton facility. The first function captures the charges associated with the Alton Facility contract. The second function captures the costs associated with the Cushion Gas. Last, the third function is the carrying costs of natural gas held in storage. In this chapter Navigant prepares the classification of costs for each function.

5.1 Approach to Classification of Costs

Navigant recommends the adoption of the Equitable Method of classifying costs of the Alton Facility, the associated Cushion Gas and the carrying costs of natural gas. Navigant recommends that this method be used as this method is used in the natural gas industry and detailed in the U.S. FERC Natural Gas Pipeline Manual[8]. The Equitable Methodology uses the following process to classify costs:

(1) Fifty percent of the fixed cost of storage is classified as Deliverability. The "Deliverability" function of a storage field refers to the ability of the storage field to withdraw gas on a particular day (FERC page 58).
(2) Fifty percent of the fixed cost of storage is classified as Capacity. The "Capacity" function refers to the storage field's capacity to store gas for a designated customer or for system operations (FERC page 58).
(3) All variable costs are classified as Injection/Withdrawal. The Injection/Withdrawal component refers to the storage fields function with injecting and withdrawing gas for customers or for system operations.

In order to account for the Natural Gas in Storage function Navigant has assumed that the average value of the inventory will be classified as fifty percent Deliverability and fifty percent Capacity.

Based upon the pricing design detailed in the contract between the Alton Facility and Heritage Gas, Navigant proposes the following classification of Alton Facility contract charges.

Table 5 – Proposed Classification of the Storage Revenue Requirement

Alton Contract Pricing Component	Deliverability	Capacity	Injection / Withdrawal
Injection / Withdrawal Commodity			100%
Inventory Demand Charge	50%	50%	
Natural Gas in Storage/Cushion Gas	50%	50%	

Application of the classification strategy outlined in Table 5 results in a classification of the indicative revenue requirement which is detailed in Table 6 below.

[8] Federal Energy Regulatory Commission Cost of Service Manual, June, 1999, p. 58.

Table 6 – Classification of the Indicative Revenue Requirement

Description	Amount	Deliverability	Capacity	Injection / Withdrawal
Total Inventory Demand Charges	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenses Associated With Injections	[redacted]	[redacted]	[redacted]	[redacted]
Total Expenses Associated With Withdrawals	[redacted]	[redacted]	[redacted]	[redacted]
Total Cost of Cushion Gas	[redacted]			
WACC	8.9375%			
	[redacted]			
Gross-up for Income Taxes associated with the Return on Cushion Gas	[redacted]			
Return on Cushion Gas	[redacted]	[redacted]	[redacted]	[redacted]
Total Cost of Natural Gas in Storage	[redacted]			
WACC	8.9375%			
	[redacted]			
Gross-up for Income Taxes associated with the Return on Natural Gas in Storage	[redacted]			
Return on Natural Gas in Storage	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue Requirement Associated with Storage	$14,041,509	[redacted]	[redacted]	[redacted]

Source: Appendix C

6. Approach to Allocation of Costs

Navigant proposes a seasonal volumetric approach for the allocation of costs to specific tariff classes. Navigant believes the seasonal volumetric approach provides a cost-justified and equitable approach to cost allocation affording benefits to all tariff classes.

6.1 Seasonal Volumetric Approach

The seasonal volumetric approach allocated storage field costs based upon usage incurred during the peak season (November to April). Navigant believes the seasonal volumetric approach is reasonable because costs are allocated based upon usage during that time of year when storage is providing service to customers. Therefore, customers using the Heritage system during summer months when the storage system is providing limited value will not be allocated costs associated with the storage system. Note that the costs associated with Natural Gas in Storage (i.e. the costs of carrying an average inventory on natural gas in the Alton facility) were not allocated to self supply tariff because the customers served under those tariffs would presumably provide their own natural gas to the Alton Facility.

Table 7 – Allocation of Alton Storage Field Costs to Tariff Classes

Alton Facility Charges	System Supply			Self Supply		Total
	Rate 1	**Rate 2**	**Rate 3**	**Rate 3**	**Rate 4.1**	**Total**
Allocator %	33.24%	29.36%	24.77%	[redacted]	[redacted]	100.00%
Alton Storage Field Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cushion Gas Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Allocator % (Natural Gas in Storage)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas in Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue Requirement						$14,041,509

Source: Appendix E

6.2 Comparison of Cost Allocation to Customer Benefits

Navigant prepared an analysis comparing the cost allocation produced by the seasonal volumetric approach discussed above to the benefits which customers are predicted to experience from the storage field. Navigant believes that any cost allocation approach which would provide a tariff group with a cost allocation greater than the benefits a group is expected to receive could be construed as not equitable even if strict cost allocation standards are met.

Navigant used data for the year 2013 and applied a simple algorithm to estimate the savings which are derived from the proposed Alton Facility if the storage facility were in place in 2013. The algorithm assumed that the storage field would receive injections during the lowest cost days and would experience withdrawals during the high cost days. Natural gas prices were based upon observed spot price values at Algonquin City-Gates. Navigant's analysis quantified a net benefit value of $33,237,202 for the storage field in 2013.

The next step in the analysis estimated the specific monthly value of the storage field for each month. Different tariff classes have varying levels of monthly usage. Navigant expects that customers using more natural gas during the winter would receive a greater benefit than customers with a more levelized natural gas consumption pattern because the storage field will generally provide the greatest utility during peak usage months.

The results of the comparison of the cost allocation to customer benefits are provided in Figure 3 below.

Figure 3 –Benefit Cost Ratio for the Seasonal Volumetric Approach

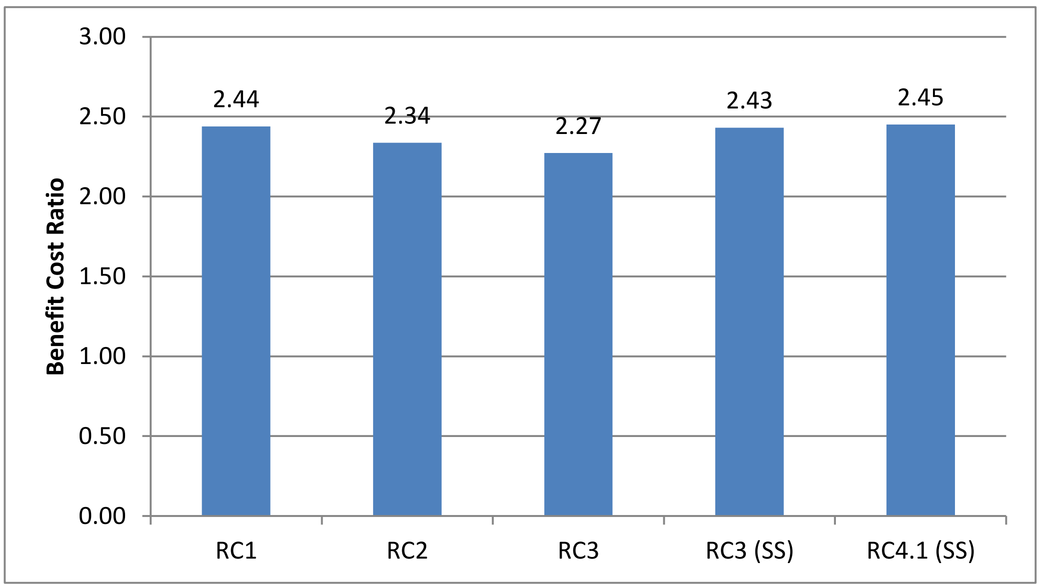


Figure 3 above illustrates that the storage field will, on average, yield a benefit-cost ratio of approximately 2.37 given market prices for the year 2013. Each tariff class is receiving something very close to the average benefit-cost ratio with Rate Class 3 receiving a ratio of 2.27 benefits to costs as the lowest benefit cost ratio and RC4.1 self supply receiving a ratio of 2.45 benefits to costs as the maximum. These values are calculated based upon the revenue requirement allocated to each rate class (or the "cost") and the estimated cost for use of the storage facility for each rate class (or the "benefit"). This "benefit" is defined by an algorithm that assumed that the storage field would receive injections during the lowest cost days and would experience withdrawals during the high cost days. Table 8 below shows the calculation of the benefit cost ratio.

Table 8 – Calculation of Benefit Cost Ratio

Description	System Supply			Self Supply		
	Rate 1	Rate 2	Rate 3	Rate 3	Rate 4.1	Total
Net Benefit	$11,480,325	$9,714,065	$7,968,372	[redacted]	[redacted]	$33,237,202
Allocated Revenue Requirement	$4,707,135	$4,157,892	$3,508,038	[redacted]	[redacted]	$14,041,509
Ratio	2.44	2.34	2.27	2.43	2.45	2.37

Navigant believes that the relatively small variance between all classes indicates that the allocation produced by the seasonal volumetric approach is equitable.

7. Proposed Pricing Design

Navigant proposes a pricing design for the recovery of storage costs offered by Heritage Gas under the following tariff classes: Rate 1, Rate 2, Rate 3, Rate 3 (self supply) and Rate 4.1 self supply. Our pricing proposal contains the following elements:

Self Supply Pricing

Pricing for the Alton Facility would be unbundled from the Cushion Gas and Natural Gas in Storage pricing. In contrast, the Cushion Gas and Natural Gas in Storage will be included in Heritage Gas rate base and receive a return.

7.1 Indicative Charges

The indicative pricing design for storage service is presented below in Table 9.

Table 9 – Proposed Storage Pricing Design for the Alton Facility

Components of Storage Charge	System Supply Charges ($/GJ)	Self Supply Charges ($/GJ)
Alton Facilities Charge ($/GJ)	$2.50131	$2.50131
Cushion Gas ($/GJ)	$0.09304	$0.09304
Natural Gas in Storage ($/GJ)	$0.18607	
Total	$2.78042	$2.59435

Source: Appendix E

Charges would be assessed on volumetric basis for all natural gas delivered during the Withdrawal Season (months of November through April).

8. Reconciliation of the Alton Facility Contract Charges

As the Alton Facility is currently in the planning stages, there is a level of uncertainty on the total expenses which this facility will charge Heritage Gas when it becomes operational. Heritage Gas will not earn a return on the expenses associated with the contractual charges from the Alton Facility the contractual charges will be an expense in the Heritage Gas revenue requirement. Further, the exact level of usage of the storage field cannot be determined at this time.

Navigant recommends that the expenses associated with the Alton Facility be treated using a Reconciling Clause Mechanism. The mechanism would be designed to provide symmetric protection to Heritage Gas and customers ensuring that the contractual expenses associated with the Alton Facility are not over- or under-recovered. Such treatment has precedent in the natural gas and electric utility industry through the implementation of purchased gas, fuel and purchased capacity adjustment clauses.

Navigant proposes the following design of the Reconciling Clause Mechanism.

Estimation of Expenses and Revenues for the First Forecast Time Period

Shortly before the Alton Facility enters service with Heritage Gas, it has been proposed that Heritage Gas provides the NSUARB with estimates of the expenses associated with the Alton Facility billed to Heritage Gas for the first year of service. Also included in the Board filing will be estimates of the revenues which Heritage Gas would anticipate receiving in the same time period from customers.

Estimation of Expenses and Revenues for the Second Forecast Time Period

During the fourth quarter in which the Alton Facility is in service, Heritage Gas will prepare and file with the Board estimates of the expenses associated with the Alton Facility billed to Heritage Gas for the second year of service. Also included in the Board filing will be estimates of the revenues which Heritage Gas would anticipate receiving in the same time period from customers.

Reconciliation of Expenses and Revenues for the First Forecast Time Period

During the first quarter of the second forecast time period Heritage Gas will prepare a reconciliation of the actual versus forecast revenues and expenses incurring during the first forecast time period. Based upon the results of the reconciliation Heritage Gas will propose a surcharge and/or refund factor targeted to achieve a zero balance in the reconciling accounts. Navigant proposes that the factors be implemented effective on July 1 and in effect for the following twelve months. This process would be repeated annually.

9. Conclusion

Navigant recommends that the Heritage Gas costs for use of the Alton Facility be classified using the "Equitable Method". The Equitable Method is recognized as the appropriate approach to cost allocation for natural gas storage fields by the United States FERC and is used in the industry. The allocation approach embraced in this analysis used techniques consistent with Heritage Gas' most recent allocated cost of service study.

The allocation of costs to each tariff class will occur using Seasonal Volumetric usage. The Seasonal Volumetric approach assess a charge to customers for all natural gas consumed during the Withdrawal Season (November to April).

Finally, Navigant is recommending the development of a reconciling clause for the charges associated with the Alton Facility and the cost to finance the inventory of natural gas in storage.

Appendix A. Glossary

BCF	Billion Cubic Feet
FERC	Federal Energy Regulatory Commission
GJ	Gigajoule
IDR	Inventory Demand Charge
M&NP	Maritimes & Northeast Pipeline
MCI	Maximum Customer Inventory
NCP	Non-Coincident Peak
WACC	Weighted Average Cost of Capital
WCR	Withdrawal Commodity Rate

Appendix B. Indicative Revenue Requirement for Storage Services

Heritage Gas		
Development of the Indicative Revenue Requirement		
Associated with Natural Gas Storage Services		
December 31, 2017		
Expenses Associated With the Cost of Storage (Alton Contract)		
Inventory Demand Rate (IDR) $/GJ/ month	[redacted] [redacted]	
Maximum Customer Inventory (MCI)	[redacted]	
Months per Year	12	
Total Inventory Demand Charges		[redacted]
Expenses Associated With Injections (Alton Contract)		
Maximum Customer Inventory (MCI)	[redacted]	
Injection Commodity Rate (ICR)	$ [redacted]	[redacted]
Expenses Associated With Injections	[redacted]	[redacted]
Maximum Customer Inventory (MCI)	[redacted]	
Estimated cost of Natural Gas in Storage - $/GJ	$ 4.25	
Percentage Fuel Gas Used for Compressors	2%	
Expenses Associated With Fuel Costs		$ [redacted]
Total Expenses Associated With Injections		$ [redacted]
Expenses Associated With Withdrawals (Alton Contract)		
Maximum Customer Inventory (MCI)	[redacted]	
Withdrawal Commodity Rate (WCR)	$ [redacted]	[redacted]
Total Expenses Associated With Withdrawals	[redacted]	[redacted]
Total Alton Facility Charges		$ [redacted]
Cost of Capital and Capital Structure		
Rate of Return (Debt)	7.25%	
Percentage of Capital Structure - Debt	55%	
Rate of Return (Equity)	11.00%	
Percentage of Capital Structure - Equity	45%	
WACC (pre-tax)	8.9375%	
Provincial and Federal Income Taxes		
Nova Scotia Provincial Tax Rate	16.00%	
Canadian Federal Tax Rate	15.00%	
Tax Rate	31.00%	
WACC (post-tax)		11.16%
Estimation of Rate Base - Cushion Gas		
Estimated Cost of Cushion Gas - $/GJ	$ 4.25	
Quantity of Cushion Gas - GJ	[redacted]	
Total Cost of Cushion Gas		$ [redacted]
Return on Cushion Gas - Pretax		$ [redacted]
Estimation of Rate Base - Natural Gas in Storage		
Estimated Cost of Natural Gas in Storage - $/GJ	$ 4.25	
Quantity of Natural Gas in Storage (System Supply)	[redacted]	
Total Cost of Natural Gas in Storage		$ [redacted]
Return on Natural Gas in Storage - Pretax		$ [redacted]
Total Revenue Requirement Associated with Alton Facility, Nat Gas Storag		**$ 14,041,509**

Appendix C. Detailed Classification of Cost

Heritage Gas									
Development of the Indicative Revenue Requirement									
Associated with Natural Gas Storage Services									
December 31, 2017									
	Storage Revenue Requirement		Classification Percentages			Classification of the Storage Revenue Requirement			
Expenses Associated With the Cost of Storage (Alton Contract)			Deliverability	Capacity	Injection / Withdrawal	Deliverability	Capacity	Injection / Withdrawal	Total
Inventory Demand Rate (IDR) $/GJ/ month	$ [redacted]								
Maximum Customer Inventory (MCI)	[redacted]								
Months per Year	12								
Total Inventory Demand Charges		$ [redacted]	50%	50%	0%	[redacted]			
Expenses Associated With Injections (Alton Contract)									
Maximum Customer Inventory (MCI)	[redacted]								
Injection Commodity Rate (ICR)	$ [redacted]								
Expenses Associated With Injections		$ [redacted]							
Maximum Customer Inventory (MCI)	[redacted]								
Estimated cost of Natural Gas in Storage - $/GJ	4.25								
Percentage Fuel Gas Used for Compressors	2%								
Expenses Associated With Fuel Costs		$ [redacted]							
Total Expenses Associated With Injections		$ [redacted]	0%	0%	100%	[redacted]			
Expenses Associated With Withdrawals (Alton Contract)									
Maximum Customer Inventory (MCI)	[redacted]								
Withdrawal Commodity Rate (WCR)									
Total Expenses Associated With Withdrawals			0%	0%	100%	[redacted]			
Cost of Capital and Capital Structure									
Rate of Return (Debt)	7%								
Percentage of Capital Structure - Debt	55%								
Rate of Return (Equity)	11%								
Percentage of Capital Structure - Equity	45%								
WACC (pre-tax)	8.9375%								
Provincial and Federal Income Taxes									
Nova Scotia Provincial Tax Rate	16.00%								
Canadian Federal Tax Rate	15.00%								
Tax Rate	31.00%								
WACC (post-tax)		11.161%							
Estimation of Rate Base - Cushion Gas									
Estimated Cost of Cushion Gas - $/GJ	$ 4.25								
Quantity of Cushion Gas - GJ	[redacted]								
Total Cost of Cushion Gas		$ [redacted]							
Return on Cushion Gas - Pretax		$ [redacted]							
Estimation of Rate Base - Natural Gas in Storage									
Estimated Cost of Natural Gas in Storage - $/GJ	$ 4.25								
Quantity of Natural Gas in Storage (System Supply)	[redacted]								
Total Cost of Natural Gas in Storage		$ [redacted]							
Return on Natural Gas in Storage - Pretax		$ [redacted]	50%	50%	0%	[redacted]			
Total Revenue Requirement Associated with Alton Facility, Nat Gas Storage & Cushion Gas			#		#	[redacted]			$ 14,041,509

Appendix D. Detailed Allocation of Costs

Indicative 2015 Rates		Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Demand - NCP		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Energy		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Percentage Allocators		Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)
Demand - Seasonal Consumption		33 24%	29.36%	24.77%	[redacted]	[redacted]
Energy		33 24%	29.36%	24.77%	[redacted]	[redacted]

Percentage Allocators (Nat Gas in Storage)		Rate 1	Rate 2	Rate 3	Rate 3 UB	Rate 4 UB
Demand - Seasonal Consumption		[redacted]				
Energy						

Alton Facility Charges	Allocator	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Deliverability	Energy	[redacted]					
Capacity	Demand - Seasonal Cons.	[redacted]					
Injection	Energy	[redacted]					
Total		[redacted]					
							$ -

Cushion Gas	Allocator	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Deliverability	Energy	[redacted]					
Capacity	Demand - Seasonal Cons.						
Injection	Energy						
Total							
							$ -

Natural Gas Storage	Allocator	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Deliverability	Energy	[redacted]					
Capacity	Demand - Seasonal Cons.						
Injection	Energy						
Total							
							$ -

Alton Facility + Cushion Gas + Nat Gas Storage	Allocator	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Deliverability	Energy	[redacted]					
Capacity	Demand - Seasonal Cons.	[redacted]					
Injection	Energy	[redacted]					
Total		[redacted]					$14,041,509
							$ -

Alton Facility + Cushion Gas + Nat Gas Storage		Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)	Total
Allocator %		33 24%	29.36%	24.77%	[redacted]	[redacted]	[redacted]
Alton Storage Field Costs		[redacted]					
Cushion Gas Costs		[redacted]					
Allocator % (Natural Gas in Storage)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Natural Gas in Storage		[redacted]					
Total Revenue Requirement							$14,041,509

Appendix E. Detailed Pricing Design

Alton Facility Charges	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)
Deliverability	$1.17805	$1.17805	$1.17805	$1.17805	$1.17805
Capacity	$1.17805	$1.17805	$1.17805	$1.17805	$1.17805
Injection	$0.14522	$0.14522	$0.14522	$0.14522	$0.14522
Total	$2.50131	$2.50131	$2.50131	$2.50131	$2.50131
$ -	[redacted]				
					[redacted]

Cushion Gas	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)
Deliverability	$0.04652	$0.04652	$0.04652	$0.04652	$0.04652
Capacity	$0.04652	$0.04652	$0.04652	$0.04652	$0.04652
Injection	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Total	$0.09304	$0.09304	$0.09304	$0.09304	$0.09304
$ -	[redacted]				
					$ [redacted]

Natural Gas Storage	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)
Deliverability	$0.09304	$0.09304	$0.09304	$0.00000	$0.00000
Capacity	$0.09304	$0.09304	$0.09304	$0.00000	$0.00000
Injection	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Total	$0.18607	$0.18607	$0.18607	$0.00000	$0.00000
$ -	[redacted]				
					$ [redacted]

Alton Facility + Cushion Gas + Nat Gas Storage	Rate 1	Rate 2	Rate 3	Rate 3 (SS)	Rate 4.1 (SS)
Deliverability	$1.31760	$1.31760	$1.31760	$1.22456	$1.22456
Capacity	$1.31760	$1.31760	$1.31760	$1.22456	$1.22456
Injection	$0.14522	$0.14522	$0.14522	$0.14522	$0.14522
Total	$2.78042	$2.78042	$2.78042	$2.59435	$2.59435
$ -	[redacted]				
					$14,041,509

Attachment 5.
Precedent Agreement between Heritage Gas and Alton
(Dated October 20, 2014)

ATTACHMENT 5.

CONFIDENTIAL

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Attachment 6.
Proposed Heritage Gas Bill Including Storage Costs

Heritage Gas
Park Place 1
200-238 Brownlow Avenue
Dartmouth, NS
B3B 1Y2
Tel: (902) 466-2003

Account No. 315485-8
Premise No. 4006895
Customer Name
Service Address AMHERST, NS

Statement Date Nov. 27, 2014

Amount Now Due $ 63.59
Amount Paid

Meter No.	Usage From	Usage To	Days	Meter Reading From	Meter Reading To	Type	Volume (m3)	X	Conversion Factors Pressure	X	Conversion Factors Energy	=	Billing GJ
1000	Oct. 19, 2014	Nov. 21, 2014	33	2,311	2,368	Actual	57		1.0136		0.03948		2.28

Your Account Information
Type: SGS Small General Service

PREVIOUS AMOUNT DUE		$ 43.09	
Payment - Thank You	Nov. 16, 2014	43.09 CR	
Balance Forward			$ -

CURRENT CHARGES from Oct. 19, 2014 to Nov. 21, 2014

Delivery Costs					
Fixed Monthly Customer Charge					21.87
Base Energy Charge					
	2.28GJ	@	$ 8.685	/GJ- Oct. 19 to Nov. 21	19.80
Commodity Costs					
Gas Cost					
	.68GJ	@	$ 5.550	/GJ- Oct. 19 to Oct. 31	3.77
	1.60GJ	@	$ 5.550	/GJ- Nov. 01 to Nov. 21	8.88
Storage Cost					
	.68GJ	@	0.000	/GJ- Oct. 19 to Oct. 31	-
	1.60GJ	@	2.7804	/GJ- Nov. 01 to Nov. 21	4.45
Municipal Payments					1.88
Sub-Total					60.65
Harmonized Sales Tax @ 15%					8.82
Provincial Rebate					5.88 CR
Total Current Charges					63.59

Amount Now Due $ 63.59

Pre-authorized payment for this statement will be made on Nov. 17, 2014

Special Messages
Effective November 1, 2014, the Gas Cost Recovery Rate will increase to $5.55 per gigajoule (GJ).