COST-BENEFIT ANALYSIS OF A NATURAL GAS LATERAL PIPELINE TO THE ANNAPOLIS VALLEY

by

William L. Turner

Thesis submitted in partial fulfillment of the
requirements for the Degree of
Bachelor of Arts with
Honours in Economics

Acadia University

April, 2011

This thesis by William L. Turner

Is accepted in its present form by the

Department of Economics

as satisfying the thesis requirements for the degree of

Bachelor of Arts with Honours

Approved by Thesis Supervisor

Dr Burc Kayahan Date

Approved by Thesis Supervisor

Dr Scott Skjei Date

Approved by the Head of the Department

Dr Paul Hobson Date

Approved by the Honours Committee

Dr Sonia Hewitt Date

Signature of Author

Date

Acknowledgements

I would like to thank Ross Craik at BMO Nesbitt Burns for initially proposing the topic for my thesis and providing everything needed to hit the ground running. Professor John Davies made his support available to me in a number of ways, particularly with how to begin the planning, research and writing entailed in an economics thesis. My other supervisors, Professor Burc Kayahan and Professor Scott Skjei, were of immense help in pushing the thesis to completion by lending me their expertise in econometrics and environmental economics. While conducting my research there were two individuals that were exceptionally helpful and went the extra mile for me, and that I would like to recognize: Chief Engineer Charles Mackillop of Acadia University and Stephen Rankin at Maritime & Northeast Pipeline. This thesis also benefited greatly from the industry experience provided through consultation and editing by Bob DeWolff and Ron Turner. The meticulous Amber Milan is also to be thanked for preventing an untold number of wayward sentences and questionable formatting.

Table of Contents

List of Tables

List of Figures

Abstract

This a study of the economic benefit of bringing natural gas to the Annapolis Valley, Nova Scotia. Large volume potential customers are profiled and found to be primarily using Bunker C residual fuel oil, which then is contrasted with natural gas in terms of use, efficiency, price and environmental effects. Based on the customers' energy needs, the construction cost of a 105km 6 inch lateral pipeline connecting to the provincial pipeline network north of Halifax is calculated. With 2010 average prices for Bunker C and natural gas a Net Present Value of $51.8 million is established for the project with a 31% Internal Rate of return and break even of four years. As the economic value of this project depends greatly on the price differential between the fuels a sensitivity analysis is conducted. The environmental costs of emissions are quantified to incorporate externalities into the analysis. Limitations of the study examine why a favourable economic analysis does not necessarily mean a viable project. Based on the IRR the project does appear financially viable from a commercial standpoint.

1 Introduction

Natural gas has become available as an energy choice for many Nova Scotian customers in the past decade as the province's offshore natural gas industry developed. The purpose of this paper is to evaluate the economic potential of a natural gas pipeline to the Annapolis Valley (Figure 1). The energy cost savings of converting potential customers in the study area to natural gas from current fuel sources is evaluated against a cost estimate of the proposed lateral pipeline. Feasibility studies have been done in the province before but many of them have become dated as they do not reflect the current energy market; one done in 2002 assumed a long term oil price of \$24.00US per barrel and natural gas price of \$4.54/MMBtu[1]. 2010 and 2011 saw oil prices occasionally climb over \$100.00US per barrel and while natural gas averaged \$4.93/MMBtu[2]. Evaluating the Annapolis Valley lateral pipeline under current conditions shows that it is economically feasible and could well be commercially profitable. In addition environmental reasons for converting to natural gas are also examined; including an attempt to quantify the environmental cost of various emissions.

---

[1] Gardner Pinfold Consulting Economists Ltd. "Natural Gas and its Impacts on Greenfield Gas Areas," Sept., 2002, pp.58, available from Atlantic Canada Petroleum Institute.
[2] Heritage Gas Inc. "Historical Rates," *Heritage Gas Inc*, 2010, accessed Mar. 2, 2011, http://heritagegas.com/historical-rates.html.

Figure 1 Annapolis Valley, Nova Scotia

1.1 Nova Scotia's Existing Network and Natural Gas Industry

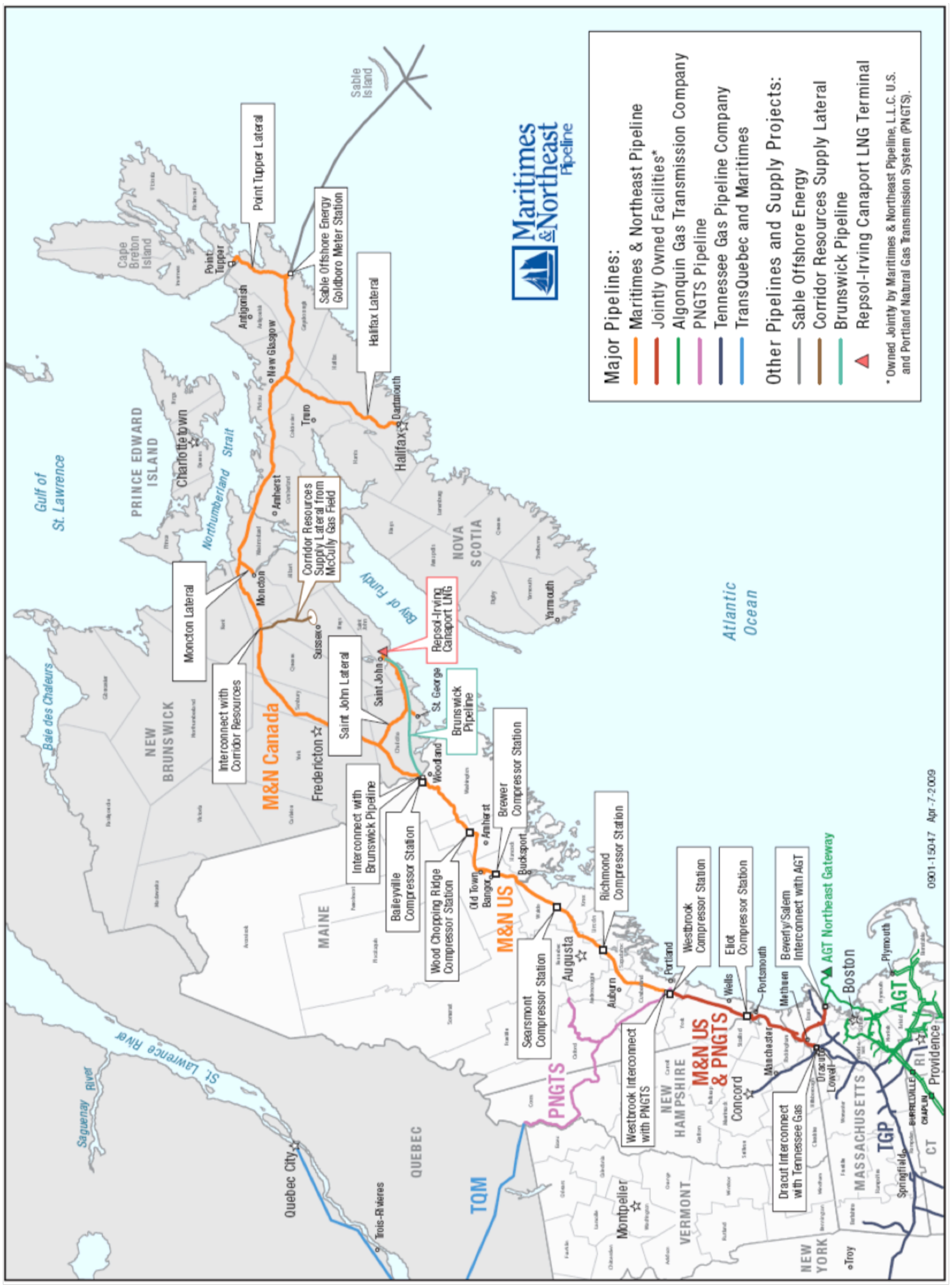
In 1999, Maritime and Northeast Pipeline (M&NP) began operation; it is a joint venture between Spectra Energy 77.53%, Emera Inc. 12.92% and ExxonMobil 9.55% (As of December 17, 2007 according to Spectra Energy's website). It is a major 1400km transmission pipeline 30 inches in diameter that runs from the coast of Nova Scotia, through New Brunswick and down into the United States to supply the pipeline grid of the Eastern Seaboard (Figure 2)[3]. It is supplied by offshore pipelines from the Sable Offshore Energy Project (SOEP). The gas is brought ashore at the Goldboro Gas Plant, capable of processing over 600 million cubic feet per day (MMSCFD)[4]. The SOEP is continuing to bring more platforms and fields online and now produces 400 to 500 MMSCFD of natural gas. EnCana is set to begin production on another

[3] Stephen Rankin, Director of External Relations Maritime & Northeast Pipeline, interview with author 2009.
[4] ExxonMobil Canada Properties Ltd. "Sable Project Operations Overview," *ExxonMobil,* 2010, accessed Jan. 24, 2010, http://www.soep.com/cgi-bin/getpage?pageid=1/0/0.

offshore natural gas project in the Deep Panuke field in 2011 with a production capacity of 300 MMSCFD[5]. Further supply to the M&NP is provided by a Repsol-Irving Canaport liquefied natural gas (LNG) terminal in New Brunswick which has (according to the Irving Oil website as of January, 2010) the capacity to import 1000 MMSCFD from LNG tankers. A third supplier to M&NP, minor but interesting because of similar possibilities in the Annapolis Valley, is the Corridor Resources Supply Lateral from the McCully Gas Field, which began producing up to 30 MMSCFD in 2007[6].

From the M&NP's main transmission pipeline in Nova Scotia several natural gas distribution laterals branch off. In 1999 Sempra Energy won a 25 year gas distribution franchise with plans to deliver gas to 78% of households in the province which they would achieve by providing service to every county in Nova Scotia[7]. Studies of laterals to each county were commissioned. In the Annapolis Valley, major industries like Minas Pulp & Paper (now Minas Pulp & Power) indicated their interest in converting to natural gas[8]. The Halifax lateral was soon underway but construction elsewhere encountered delays.

[5] EnCana. "Deep Panuke Volume 1 (Project Summary)," November 2006.
[6] Corridor Resources Inc. "A History of the McCully Field," *Corridor Resources Inc.*, 2008, accessed January 24, 2010, http://www.corridor.ca/operations/mccully-field-history.html.
[7] Sempra Energy. "Sempra Energy Wins Lucrative Nova Scotia Gas Distribution Project; New System Will Be Largest…" *Business Wire*, Dec. 16, 1999, accessed Jan. 24, 2010, http://www.allbusiness.com/energy-utilities/utilities-industry-electric-power/6776078-1.html.
[8] John Woods, Vice President Minas Pulp & Power, interview with author, 2010.



Source: Maritime & Northeast Pipeline (April 7, 2009)

The primary issue was a dispute between Sempra Energy and the Department of Transportation and Public Works revolving around using the 'right of way' of provincial highways, the buffer of land alongside the highway, for their pipelines. While the construction disputes dragged on, the price of natural gas more than tripled – Sempra had tried to include a clause allowing the halt of construction at any point if the price differential of natural gas to oil fell below $3.50/MMBtu making it a difficult for Sempra to secure new customer commitments. The end result was that Sempra Energy, after investing $35 million US and building only 15km of pipeline, surrendered the Nova Scotia natural gas distribution franchise after questioning whether in 'the current regulatory environment, a viable business case (could) be made for moving forward in Nova Scotia.[9]'

Heritage Gas, owned by AltaGas Utility Group Inc., holds the distribution franchises in six counties of Nova Scotia although there is not yet a franchise applied for or awarded in the Annapolis Valley (Figure 3). Heritage Gas owns a 229km network of plastic and steel pipe which brings gas to approximately 2,500 residential and commercial customers in Nova Scotia[10]. The primary lateral is a 124km 12 inch pipeline to Halifax anchored by a natural gas power generation facility that consumes up to 88,000 million British Thermal Units (MMBTU)/day. They also constructed a 17.6km lateral to Amherst in 2005[11] and have future plans for laterals to New Glasgow in Pictou County and Truro in Colchester, each of which would require a 20-25km high pressure lateral line.

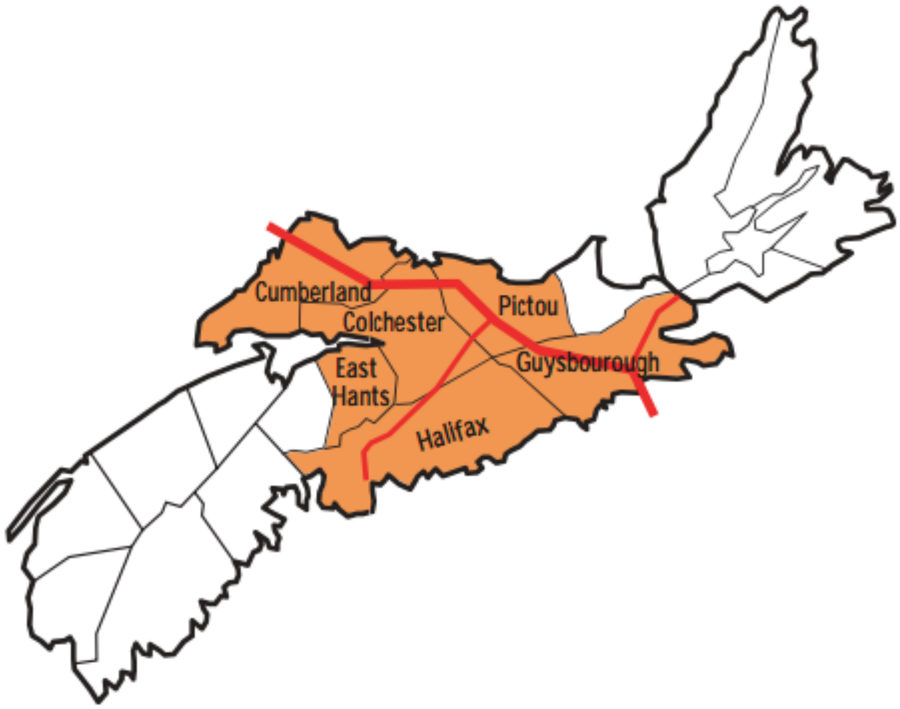
---

[9] Sempra Energy. "Sempra Energy Unit To Surrender Nova Scotia Natural Gas Distribution Franchise," *Sempra Energy,* Sept. 24, 2001, accessed Jan. 24, 2010, http://investor.shareholder.com/sre/releasedetail.cfm?ReleaseID=75747.

[10] Clare Mellor, "Alberta firm buys Heritage Gas," *Chronicle Herald*, Nov. 4, 2009, sec. L.

[11] Heritage Gas Inc. "Registration of Undertaking for Environmental Assessment: Heritage Gas Amherst Pipeline," *Nova Scotia Environment & Labour Library*, Dec 3, 2004, accessed Jan. 26, 2010, http://gov.ns.ca/nse/ea/amherstpipeline/Heritage-AmherstPipeline-PublicNotice.pdf.

Figure 3 Heritage Gas Franchise Areas

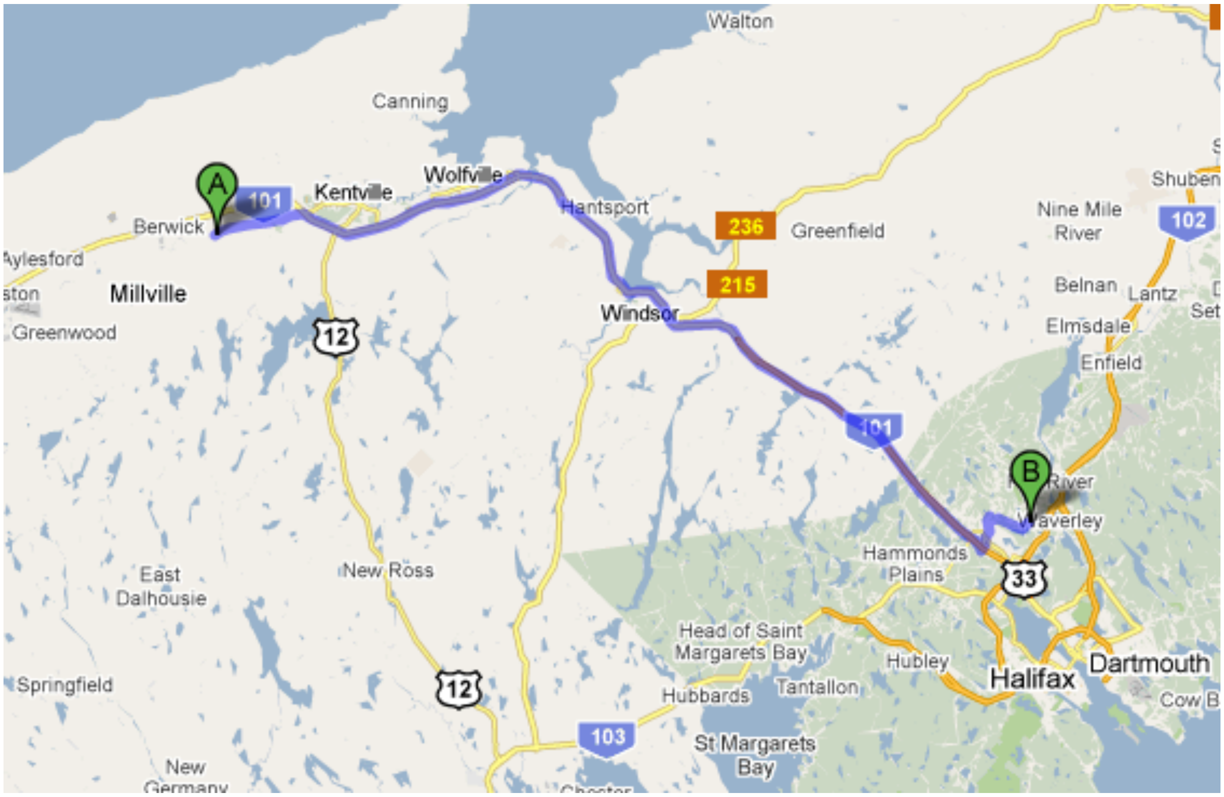


Source: The Maritimes Natural Gas Market. National Energy Board. June 2003

1.2 Study Area

The Annapolis Valley lateral would branch off the Halifax lateral at Miller Lake based on consultations with Maritime and Northeastern Pipelines (Figure 4). It would run northwest past Windsor to Wolfville and then west to Waterville (Figure 5).

Figure 4 Annapolis Valley Lateral Pipeline Route



Source: Google Maps

Figure 5 Study Area

Source: Google Maps

1.3 Potential Natural Gas Customers

In order to see a timely return on investment, pipelines typically rely on initially connecting large volume customers; smaller residential and commercial customers typically connect gradually once the core infrastructure is in place. There are four potential large volume 'anchor load' customers within the study area.

1.3.1 Michelin

A large industrial user, the Michelin Waterville plant has around 1200 employees and produces 5000-6000 industrial sized tires per day making it the second largest producer in North America by tonnage[12]. The scale and nature of the operation makes a natural gas co-generation (electricity and heat) generator a possibility. A Michelin plant in Italy has done just that, installing a 43 MW natural gas co-generation plant[13]. One attraction of onsite co-generation could be a more reliable power supply; the Waterville Michelin plant suffered significant losses when it temporarily lost power during the winter in 2009. The plant currently uses fuel oil No. 6, Bunker C.

1.3.2 Acadia University

Wolfville's Acadia University with a combined 3000 students, faculty and staff, uses a central heating system wherein the heat for most of the buildings on campus is provided by the boilers from one central location. Other fuel sources including wood chips and even fish oil have been considered but Acadia currently uses Bunker C. It receives over a hundred truckloads of the fuel per year from the Dartmouth refinery. Two of its four boilers are new (2007) and multi-fuel,

---

[12] Canadian Army. "Michelin Tire Plant," *Flickr*, Nov. 27, 2009, accessed Mar. 6, 2011, http://www.flickr.com/photos/canadianarmy/4332502761/.

[13] GE Energy. "Michelin Tire Manufacturing Facility in Italy to Be Driven by GE Energy Aero derivative Gas Turbine Generator," *ThomasNet News*, Nov. 16, 2006, accessed Feb. 25, 2010, http://news.thomasnet.com/companystory/Michelin-Tire-Manufacturing-Facility-in-Italy-to-Be-Driven-by-GE-Energy-Aeroderivative-Gas-Turbine-Generator-500100.

making an easy switch to natural gas possible[14]. As an institution that lists 'protection and sustainability of the environment' as one of its core values, the opportunity to use a greener fuel is of particular interest.[15]

1.3.3 Valley Regional Hospital

Located in Kentville the Valley Regional Hospital has 700 employees and sees over 1000 patients per day. Their current energy source is wood chips combined with No. 2 Heating Oil. The Hospital's engineer, John Madden, mentioned in an interview that wood chips require constant transfer from bins to the boiler and cause tremendous wear on the boiler system. High particulate matter emissions are characteristic of wood burning, so air quality issues are a major concern. The top of the boiler stack and fresh air intake into the hospital are at the same height, exacerbating this issue. The hospital's two boilers were installed in 2005 and are capable of using natural gas.

1.3.4 Minas Basin Pulp and Power

Formerly Minas Basin Pulp and Paper, they initially expressed interest in natural gas when contacted by Sempra in 1999. They have since diversified and are no longer looking for other fuel sources. Minas Basin has two hydro dams built in 1935 that provide a combined 5 MW to the plant and is heavily involved in tidal power projects, although these have yet to produce any power. They still use Bunker C but are planning to purchase a wood chip or pulverized 'wood flour' boiler[16]. Although this is a large industrial consumer on the same scale as Michelin, their numbers will not be included in cost-benefit calculations as in an interview with Vice President John Woods he stated they are not currently interested in natural gas. As

---

[14] Charles Mackillop, Chief Engineer Acadia University, interview with author, 2010.

[15] Acadia University. "Strategic Plan for Acadia University: Personalized Education for a Complex World," *Acadia University Board of Governors*, 2006, accessed Feb. 23, 2010, http://board.acadiau.ca/tl_files/sites/board/resources/PDF%20Files/Acadia_Strategic_Plan[2006]3.pdf.

[16] Andrew Safer, "Minas Basin's green revolution," *Canadian Consulting Engineer*, Mar., 2010, accessed Mar. 12, 2011, http://www.canadianconsultingengineer.com/issues/story.aspx?aid=1000364041.

tidal power remains unproven and there are undesirable aspects to wood generation, Minas Basin Pulp and Power could in reality, find gas the natural transition from Bunker C if it were made available.

1.3.5 Residential and Commercial

'Anchor load' customers may provide the economics to justify a pipeline but residential and commercial customers (where the density justifies it) will be expected to gradually convert to natural gas over a period of years. It may only make economic sense to buy a new $3000 natural gas furnace when the current one needs to be replaced. The Annapolis Valley has over 14,000 people living in towns (see Table 1). Together this could eventually be a significant source of demand but not in the time period looked at to justify pipeline construction.

Table 1 Annapolis Valley Population

Town	Population
Waterville	856
Kentville	5,815
New Minas	4,082
Wolfville	3,772

Source: Statistics Canada, 2010.

This often ends up a regulatory issue as government may not view it as ideal for industrial users to bypass distribution networks to connect directly to the mainline. This eliminates a major customer and source of revenue for a natural gas distribution company such as Heritage Gas, who might no longer be interested in constructing distribution infrastructure in the area. As such, Nova Scotia's franchise agreements prohibit 'bypass' access for the first 10 years although the pipeline network consisted primarily of bypasses initially[17].

1.4 Conversion Costs

The Nova Scotia government has previously assisted hospitals and universities making the conversion, with a $3.5 million expenditure in 2007 to assist Halifax's Capital Health switch its systems to natural gas[18], $368,000 (75% of total cost) to Mount Saint Vincent University in 2010[19] and $1.4 million to Dalhousie University through the Gas Market Development Fund in 2011[20]. The Gas Market Development Fund is a Department of Energy program supported by gas producers in the province and administered by Heritage Gas, in 2002 it had spent $14 million of its initial $20 million[21]. Converting from Bunker C to natural gas, is not quantified for each case as the age and type of the current boilers among other factors would have to be analyzed at the time a switch to natural gas was considered. Since the customers could expect financial assistance from the Nova Scotia government in converting their systems, the cost is not likely to be an obstacle to the project.

2 Natural Gas and Bunker C

In the study area the current primary industrial fuel source is No. 6 Heavy Fuel Oil, often known as Bunker C, for the facilities it is stored in. Although Bunker C is a fossil fuel like

[17] Canada, National Energy Board. "The Maritimes Natural Gas Market," June, 2003.
[18] CBC News. "Halifax to get natural gas by December," *CBC News Canada*, Aug. 14, 2007, accessed Jan. 13, 2010, http://www.cbc.ca/news/canada/nova-scotia/story/2007/08/14/natural-gas.html.
[19] Mount Saint Vincent University. "Mount Saint Vincent University goes even greener," *Mount Saint Vincent University*, Sept. 28, 2010, accessed Feb. 20, 2011, http://www.msvu.ca/en/home/aboutus/mediacentre/mediareleases/Sept28_2010_2.aspx.
[20] Dalhousie University. "Dalhousie University switches to Natural Gas," *Dalhousie University Media Centre*, Feb. 14, 2011, accessed Feb. 20, 2011, http://media.dal.ca/?q=node/104.
[21] Nova Scotia Department of Energy. "$14 Million Allocated for Use of Natural Gas," *Nova Scotia Canada*, Oct. 10, 2002, accessed Feb. 20, 2011, http://www.gov.ns.ca/news/details.asp?id=20021010003.

natural gas, in many ways they occupy opposite ends of the spectrum. Natural gas consists primarily of methane, a single carbon with four hydrogen atoms, while Bunker C has a variable composition of hydrocarbon chains 20-70 carbon atoms in length[22] giving it very different physical properties, emissions, uses and production processes.

2.1 Characteristics of Bunker C

Known as a 'residual' fuel oil, Bunker C is a byproduct of the oil refining process. Crude oil is heated and separated through fractional distillation which extracts the lighter more valuable hydrocarbons that vaporize at lower temperatures: gasoline, diesel, lighter fuel oils and other products which are often then further refined. The mixture of the final hydrocarbons to vaporize, a tar-like substance about one grade above asphalt, is residual fuel oil. This heavy fuel oil has limited applications due to its high viscosity, requiring significant preheating to be pumped. Although it enjoys a 2.0-2.5% combustion efficiency advantage over natural gas, as its combustion produces less moisture, the extra costs in equipment and maintenance involved in working with this fuel increase its true cost and reduce system efficiency:[23]

2.1.1 The Full Cost of Bunker C

Using Bunker C necessitates additional equipment, it must be stored, heated, pumped, atomized and requires additional maintenance.

Oil Storage An adequate supply of Bunker C must be kept in large storage tanks for each boiler. Storage tanks must also be kept as full as possible to minimize moisture build up. Maintaining a stock ties up resources but also creates exposure to the environmental risk of leaks. Michelin has already encountered this problem at their

[22] International Organization for Standardization. "Petroleum products – Fuels (class F) – Specifications of Maritime fuels," *International Standard*, 3rd ed., Nov. 1, 2005, reference number ISO 8217, accessed Mar. 2, 2011, http://lib.semi.ac.cn:8080/tsh/dzzy/wsqk/standard/ISO8217.pdf.
[23] *Techline*. "The True Cost of #6 Oil," accessed Jun. 18, 2009, http://www.pseg.com/customer/business/industrial/convert/cost.jsp.

Bridgewater plant when in 2009 several hundred liters of Bunker C leaked from a storage tank. This temporarily halted operations at the plant but fortunately the spill was contained before it could reach a nearby river[24].

Oil Additives Bunker C contains elements including sulfates and vanadium that create fuel ash corrosion when heated[25]. Additives such metallic oxides are required in order to combat this although these also increase soot production.

Oil Heating Bunker C must be continuously circulated by pumps within the tanks to ensure the additives are dispersed and a consistent viscosity is achieved. This necessitates continuous heating of the storage tanks to 49°C with a steam heat exchanger or electric element within the tank. Heat loss from the storage tank is often one of the largest inefficiencies in Bunker C use, particularly in Canadian climates[26].

Oil Pumping and Atomization In addition to the pump required within the storage tank Bunker C must be pumped to the burner. Once at the burner it still must be atomized into small droplets to be used, this is done with compressed air or steam.

Soot Blowing The quantity of impurities typically present in Bunker C makes soot a particular problem. Carbon ash builds up inside the boiler, insulating it and reducing efficiency as well as creating potentially dangerous temperature imbalances. This must be cleared with a soot blower – or in some cases by burning natural gas - on a daily

---

[24] The Canadian Press. "Oil leak shuts Nova Scotia tire plant," *The New Glasgow News,* Dec. 30, 2009, http://www.ngnews.ca/Business/Employment/2009-12-30/article-800334/Oil-leak-shuts-Nova-Scotia-tire-plant/1.
[25] Carl Branan, "Rules of Thumb for Chemical Engineers: Fourth Edition," (Oxford: Elsevier Inc., 2005) p.294.
[26] Union Gas Ltd. "Thermal Losses," *Union Gas*, accessed Feb. 24, 2011, http://www.uniongas.com/business/gastechnology/productsservices/heating/parasitic/thermal.asp.

basis[27], this particulate is flushed straight into the environment unless the boiler is not also equipped with a dust collector[28].

Makeup Water Water used as steam for heating the storage tank, atomization and soot blowing is released into the environment to prevent possible contamination of water in the boiler system. This water is replaced by 'Makeup Water' which must be heated and treated so as not to create a temperature shock in the boiler and to remove corrosive oxygen[29].

Additional Maintenance The extra pumps, storage, heating and corrosion involved with burning Bunker C unsurprisingly result in relatively higher needs for maintenance to the point where additional employees may be required.

In 2002 Dr. Herbert M. Eckerlin of North Carolina University produced a detailed study (for a consortium of natural gas utilities) that examined 67 boilers over a period of several years and quantified the additional costs and losses associated with use of Bunker C. His findings (summarized in Table 2) show that although the heat loss due to additional moisture favours Bunker C by 2-2.5% of the operating cost, once other thermal losses and additional costs are added, natural gas has the advantage by approximately 3.5%, not including storage tank heat loss which Dr. Eckerlin estimated at 8.4% in a later study[30].

---

[27] *Techline*. "True Cost of #6 Oil."
[28] Thomas Yoon, "Blow Away Your Soot," *Marine Engineer World*, 2010, accessed Feb. 28, 2011, http://www.free-marine.com/i3eng-sootblower.htm.
[29] *Techline*. "True Cost of #6 Oil."
[30] Herbert Eckerlin, "Boiler Operating Costs with Natural Gas and #6 Oil," *Union Gas*, Mar. 27, 2002, accessed Feb. 28, 2011, http://www.uniongas.com/largebusiness/customerinformation/presentations/ProfEckerlin.pdf.

Table 2 Thermal Losses and Additional Costs in Bunker C boilers

	% Increase in Cost
Oil Storage	0.52
Oil Pump	0.20
Oil Additives	1.42
Oil Heating	0.55
Soot Blowing	0.35
Makeup Water (incl. treatment and heating)	0.28
Oil Atomization	1.36
Storage Tank Heat Loss	8.40
TOTAL	**13.08**

Source: Dr. Herbert Eckerlin. An Analysis of the Losses and Costs Associated with Oil versus Gas Firing in Fuel Burning equipment.

When a new Bunker C and a natural gas fired boiler are compared it would appear that the natural gas fired boiler will have a modest efficiency advantage. Given Bunker C's base advantage in heat lost to moisture it is still 10% behind natural gas. Assuming storage tanks can be better insulated, many of those in Dr Eckerlin's study were single walled, the efficiency advantage for natural gas is still too large to ignore. A 5% increase to the price of Bunker C for associated costs and thermal losses is used for the NPV calculations in this paper.

2.1.2 Bunker C Use

The use of Bunker C requires a boiler so large as to preclude it from many applications such as residential heating. Smaller, residential boilers, use relatively expensive - more than double the price[31] - No. 2 'Light Fuel Oil'. Figure 6 shows the Canadian sectors that use Bunker C. Its market share of industrial and commercial consumers is steadily declining in the face of competition from natural gas and the imposition of more stringent environmental regulations. In the 1970s Bunker C made up 20% of all United States oil use. By 1997 this had fallen to 4%[32]. British Columbia's pulp and paper industry reduced Bunker C use by 89.8% from 1990 to 2005[33]. Many of the mills did so by converting to natural gas. Atlantic Canada constitutes approximately half of Canada's heavy fuel oil demand as can be seen in Table 3. Power generation accounts for much of this; 15% of generation in the region is from heavy fuel oil while it makes up no more than 1% of generation in other provinces[34]. Bunker C also supplies the majority of maritime transportation fuel needs, 60.7%, with diesel making up the other 39.7%. International regulations limiting the amount of sulphur in fuel may soon force ships to switch to a blend with lighter fuels or abandon Bunker C altogether in coastal waters and lakes.

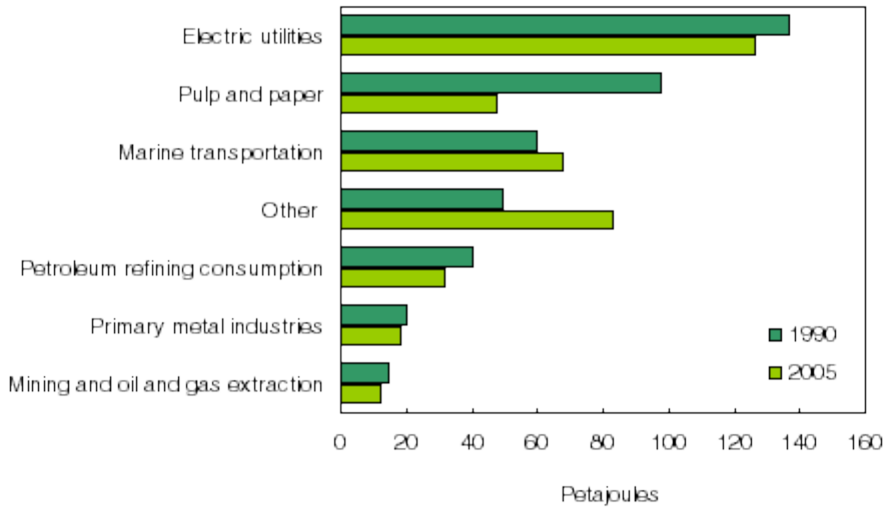
Table 3 Heavy Fuel Oil Demand by Region

	1990	**1995**	**2000**	**2005**
Atlantic provinces	189.5	152.7	178.2	172.1
Quebec	105.6	70	83.9	105
Ontario	70.9	46.9	50	58
Other provinces and territories	53.5	32.8	39	52.2
Canada	**419.5**	**302.4**	**351**	**387.3**

Source: Statistics Canada. CANSIM tables 128-0002 and 128-0009

[31] Kristin Miller, "NYC Buildings Burning Residual Fuel Pollute City's Air," *heatingoil.com*, Dec. 18, 2009, accessed Feb. 25, 2011, http://www.heatingoil.com/blog/nyc-buildings-burning-residual-fuel-pollute-citys-air1218/.
[32] United States Energy Information Administration, "Oil Market Basics: Demand," *U.S. E.I.A. Independent Statistics & Analysis*, accessed Feb, 2011, www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/demand_text.htm.
[33] Gardner Pinfold Consulting Economists Ltd. "Natural Gas, Greenfield."
[34] Paul McPhie and Anthony Caouette, "Heavy Fuel Oil Consumption in Canada," *Statistics Canada*, Nov. 12, 2009, accessed Feb. 28, 2011, http://www.statcan.gc.ca/pub/11-621-m/11-621-m2007062-eng.htm.

Figure 6 Canadian Heavy Fuel Oil use by Sector



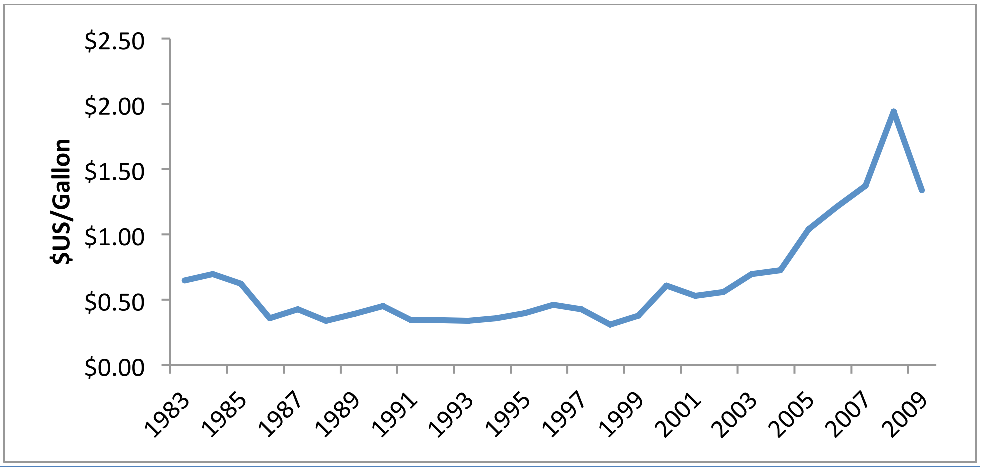
Source: Statistics Canada, CANSIM tables 128-0002 and 128-0009.

2.1.3 Bunker C Price

Bunker C price has followed general energy price trends although it does not always mirror the volatility in the price of oil (Figure 7). When oil prices rise, the cost differential between No. 2 fuel oil and Bunker C widens faster than the price of Bunker C increases. This actually makes Bunker C more attractive in many cases despite its increase in price. New York is finding plans to eliminate Bunker C use much more costly with recent high oil prices[35]. In 2011 supply disruptions in Libya, an exporter of low sulphur 'light crude', caused crude oil prices to rise dramatically. As some refineries switched to supplies of 'heavy crude' oil, which contains proportionately more Bunker C, the shock was softened for Bunker C consumers.

[35] Energy Policy Research Foundation, Inc., "The Cost of Banning No. 6 Oil in New York City," *Energy Policy Research Foundation, Inc.*, Feb. 23, 2011, accessed Feb. 28, 2011, http://eprinc.org/?p=714.

Figure 7 U.S. Residual Fuel Oil Sales



Source: U.S. Energy Information Administration

2.2 Characteristics of Natural Gas

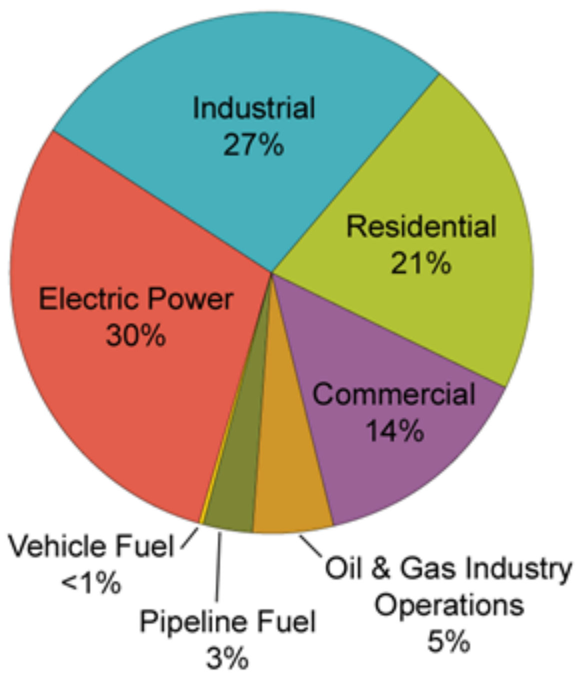
Natural gas has quite a different set of challenges to overcome; it also was once considered a residual byproduct of the oil industry. As the gas is processed, the more valuable and complex hydrocarbons like propane and butane are removed as well as other gases (CO_2, O_2). The natural gas that remains consists primarily of methane (CH_4) and variable amounts of other short hydrocarbon gases like ethane (C_2H_6). Natural gas is a clean burning fuel that is unfortunately not very dense. Without high pressure or freezing temperatures to liquefy it, natural gas does not achieve the densities needed to make transportation via pipeline or tankers viable. Oil fields and coal reserves generally contain natural gas. In the past – and still in less developed areas - if there was not demand for natural gas in close proximity to the wellhead it would simply be flared off as a waste product[36]. However, demand for this clean and easy to use fuel has developed and natural gas fields are now as sought out as oil fields and coal reserves.

[36] Jeff Johnson, "Valuing Flared Natural Gas," *Chemical & Engineering News* 85 (Sept. 10, 2007): 10, http://pubs.acs.org/cen/news/85/i37/8537notw5.html.

2.2.1 Natural Gas Use

The competitive price of natural gas has allowed it to displace fuel oil almost everywhere it is made available. Over half the homes in the U.S. use natural gas as their primary heating fuel and often to power household appliances[37]. Natural gas was also used to generate 23% of electricity in the U.S. (accounting for 30% of natural gas use, shown in Figure 8) in 2009; Bunker C accounted for only 1% of power generation[38].

Figure 8 Natural Gas Use in the United States, 2009

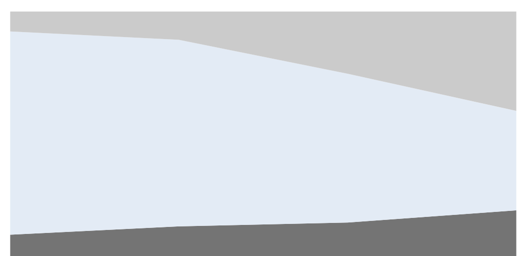


Source: U.S. Energy Information Administration, *Natural Gas Monthly* (February 2010).

[37] United States Energy Information Administration, “Natural Gas Explained,” *U.S. E.I.A. Independent Statistics & Analysis*, accessed Feb. 25, 2011, http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_use.
[38] United States Energy Information Administration, “Electricity Explained,” *U.S. E.I.A. Independent Statistics & Analysis*, accessed Feb. 25, 2011, http://www.eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states.

Nova Scotia's power generation portfolio (Figure 9) remains heavily reliant on coal and Bunker C although they optimistically forecast an increasing share of natural gas and renewable resources. Natural gas power plants are a natural partner to renewable tidal, wind and solar generation which lack predictability or control as power sources. Natural gas 'peaking' generators can be brought online when peak energy demand is not being met.

Figure 9 Nova Scotia's Past Power Generation and Future Goals (%)

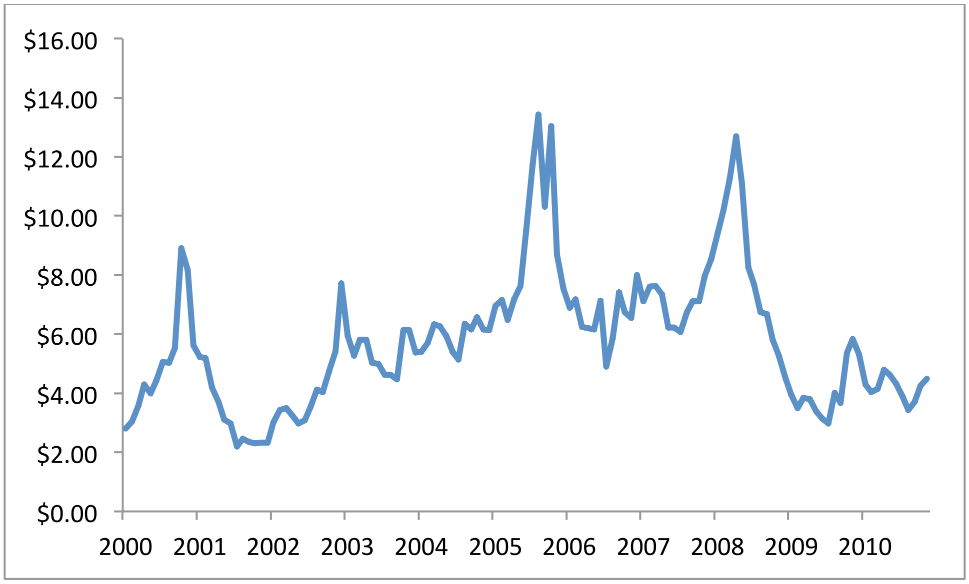


	2001	2009	2015	2020
Renewables	8	11.3	25	40
Coal/Bunker C	82	75.3	60	40
Natural Gas	10	13.3	15	20

Source: Nova Scotia Department of Energy, 2010

2.2.2 Natural Gas Prices

Figure 10 Henry Hub Natural Gas Spot Price (USD)



Source: U.S. Energy Information Administration, 2011

Natural gas has customarily been priced at a discount to heavy fuel oil. While competitive, its price is subject to high volatility (Figure 10) as pipeline supply capacity is fixed in the short term and developing new supply has a lengthy lead time. Storage facilities can ameliorate some of the short term and seasonal volatility but Nova Scotia has yet to develop them[39]. Price surges that saw the price of natural gas double or more in the past decade were enough to put some businesses that had paid to convert their systems in serious financial trouble. There is an overall consensus among forecasts that the price of natural gas will stabilize at low to moderate levels for an extended period. The reason for this optimism is the development of vast domestic unconventional shale gas reserves in North America (Figure 11).

[39] Canada, National Energy Board. "The Maritimes Natural Gas Market," June, 2003.

Figure 11 Major North American Shale Gas Deposits

The Marcellus Shale reserve in the northeastern U.S. may have enough reserves to power the entire U.S. for decades. These unconventional gas fields were unreachable by conventional drilling but have since been made accessible with advances in drilling techniques. Not only are rigs now able to drill down to the depths required for shale reserves they have also developed horizontal drilling and 'fracking', wherein water and other chemicals are forced into the shale, fracturing it and releasing gas pockets. This new technique is attracting a great deal of attention from environmental groups concerned with the large quantities of waste water and potential contamination[40]. Quebec imposed a moratorium on new 'fracking' natural gas exploration in March, 2011 until the environmental consequences are more fully understood[41]. Elsewhere in Canada and U.S. governments have done little to restrict operations. The natural gas industry has a longer history in other regions and is perhaps seen as crucial to national energy strategies.

---

[40] Jim Efstathiou Jr. and Kim Chipman, "Fracking: The Great Shale Gas Rush," *Bloomberg News*. March 3, 2011. Accessed March 12, 2011, http://www.businessweek.com/magazine/content/11_11/b4219025777026.htm

[41] News Inferno, "Fracking Suspended in Quebec Following Release of Government Report," *News Inferno*. March 9, 2011, Accessed March 12, 2011, http://www.newsinferno.com/fracking/fracking-suspended-in-quebec-following-release-of-government-report/

2.3 Emissions and Environment

As demonstrated in Table 4, natural gas creates fewer emissions and pollutants than any other fossil fuel. Being the least chemically complex of fossil fuels allows it to be more easily fully combusted, resulting in carbon emissions approximately 30% lower than Bunker C.

Table 4 Pounds of Air Pollutants Produced per Billion Btu

Pollutant	Natural Gas	Bunker C	Coal
Carbon Dioxide	117000	164000	208000
Carbon Monoxide	40	33	208
Sulphur Dioxide	0.6	1122	2591
Particulates	7	84	2744
Formaldehyde	0.75	0.22	0.221
Mercury	0	0.007	0.016

Source: U.S. Energy Information Administration

Bunker C's major environmental problem is its high sulphur content which can cause acid rain as well as resulting in sulphuric acid in any boiler that allows moisture buildup. Control of sulphur emissions is the primary form of regulation imposed on Bunker C internationally. It has a sulphur content of up to 3% by weight in some cases with a Canadian average of 1.6% in 2005. There is no federal regulation of Bunker C sulphur content, unlike diesel and gasoline, although many provinces have set standards. New Brunswick limits sulphur content in heavy fuel oil to a relatively high ceiling of 3% (adopted 1998) and Nova Scotia to 2.2% by weight, 2.0% on an annual basis (adopted 2005). These are higher than other provincial limits of 1% by 2010 in Ontario and 1.1% in British Columbia (1989 Waste Management Act). International maritime regulations were applied to the Baltic Sea in 2006 that required ships to keep fuel sulphur levels under 1.6%, necessitating the blending of Bunker C with other fuels in many cases.

Both the U.S. and Canada are also looking into a similar North American plan that would take effect in 2012[42]. Proposals to altogether ban Bunker C from use on the Great Lakes and near port cities, where air pollution is above legal limits, are also gathering support[43]. The U.S. government has chosen to deal with sulphur emissions through a 'cap and trade' system as well as emissions standards.

While not generally involved with acid rain or the greenhouse effect, particulate emissions are of particular concern for health and visibility. Bunker C still sees use heating old apartments in New York although this is currently being phased out in favour of fuel oil No. 2 (seen next to Bunker C in Figure 12), fuel oil No. 4 and natural gas. This change is estimated to decrease particulate emissions in each building by up to 95% and by some estimates save 188 lives per year in the city as air quality improves[44].

Figure 12 Fuel Oil No.2 (left) and No. 6 (right)

Source: Environmental Defense Fund, edf.org

[42] Paul McPhie and Anthony Caouette, "Heavy Fuel Oil Consumption in Canada," *Statistics Canada*, Nov. 12, 2009, accessed Feb. 28, 2011, http://www.statcan.gc.ca/pub/11-621-m/11-621-m2007062-eng.htm.
[43] Roger Harrabin, "Harrabin's Notebook: Shipping Carbon," BBC News, July 14, 2009. Science and Environment.
[44] Kristy Kershaw, "Study: NYC Could Save 188 lives, $5billion per year with Ban of Dirty Heating Oils" heatingoil.com, January 22, 2010. Accessed February, 2011, http://www.heatingoil.com/blog/study-nyc-save-188-lives-5-billion-year-ban-dirty-heating-oils/

3 Methodology

A Cost Benefit Analysis (CBA) is an economic approach used to judge the feasibility of a project. The cost of the project is weighed against future flows of costs and benefits which are discounted to account for the opportunity cost of capital to arrive at a 'present value' for each flow. By adding up the present value of the future flows of costs and benefits a Net Present Value (NPV) is created for the project (formulas contained in Appendix A). The NPV is a dollar estimate of how much would be gained, or lost, by going ahead with the project. A positive NPV means the project is feasible.

The Internal Rate of Return (IRR) is based on the same principles as the NPV. When you set the discount rate to the IRR, there is zero NPV. Therefore if IRR is higher than the discount rate, there is a positive NPV. IRR can be viewed as the rate of return on the investment of the pipeline. For this lateral to be financially viable, a pipeline construction company would be looking for an IRR higher than their cost of capital (discount rate). Companies also require timely returns, making the 'break even' year important to them. This is the year in which the NPV turns positive.

NPV for this lateral will be calculated based on 20 years of future benefits and examined at a 4% (base case) discount rate, as well as 2% and 6% for sensitivity analysis. A commercial study would likely use a higher discount rate and look for the 'break even' point to be achieved in a 10 year time frame[45], but for the purposes of calculating the full economic benefit of the project it would be insufficient. The full economic benefit can be used to justify government assistance if there are strong long term benefits.

[45] Gardner Pinfold Consulting Economists Ltd. "Natural Gas and its Impacts on Greenfield Gas Areas." September, 2002.

3.1 Benefits

The benefit for this project is the energy cost savings, the price differential between the two fuels, multiplied by the amount of fuel consumed (for formula see Appendix A.1). First the potential quantity of natural gas demand is calculated by finding the energy requirements for each of the large energy consumers previously identified in the Annapolis Valley.

3.1.1 Energy Use of Anchor Load Customers

Details of the calculations used for each customer are available in Appendix A.1.1

- **Acadia University** The energy demands for Acadia was based off total Bunker C deliveries in 2009. It was translated into an average daily use and converted to British thermal units.
- **Valley Regional Hospital** Annual energy use at the hospital is difficult to measure as they use wood chips as well as fuel oil. With 700 employees, 100 consultants, volunteers and over 1000 patients per day the hospital is about half the size of Acadia University. Hence, in calculating the daily energy consumption for the Valley Regional Hospital, we assume that their demand for energy will be proportional to Acadia University's daily consumption of Bunker C (i.e. 50% of Acadia's energy consumption).
- **Waterville Michelin** A Michelin plant in Italy has installed a 43 megawatt natural gas turbine generator which will be in continuous operation with 40% of its electricity production (15.2 megawatts) consumed by the Michelin plant and the surplus sold to the market. The gas turbine is used for co-generation (heat and electricity) so this may be underestimating the total energy needs of the Michelin plant. An alternative method, using a Michelin plant in Bridgewater, Nova Scotia and resulting in a slightly lower estimate is also available in Appendix A.1.1. If Michelin did choose to install natural gas power generation it

could potentially make sense to do so on a scale that would allow them to provide additional power for the regional grid. This would result in significantly higher consumption.

- **Average Natural Gas Required**

Table 5 Average Fuel Consumption

Consumer	MMBtu/day	% of Total
Acadia	410	22%
Hospital	205	11%
Michelin	1246	67%
Total	**1861**	100%

Adding up the average daily fuel use in Table 5, we get a total of 1861MMBtu/day for the Annapolis Valley. In Appendix A.1.1 the total consumption is calculated to be equivalent to an annual average of 1.8 million standard square cubic feet per day (MMSCFD) which will later be used to assist the selection of pipe diameter.

3.1.2 Fuel Cost per MMBtu

3.1.2.1 Bunker C

For Bunker C price, detailed records of Acadia University's 2010 costs, including delivery charges are used. In order to make a direct comparison of Bunker C and natural gas prices, units are converted to $/MMBtu. This is then increased by 5% for the additional costs associated with Bunker C based on Table 2. Calculations in Appendix A.1.2.1 put a price on Bunker C of $12.75/MMBtu.

3.1.2.2 Natural Gas

Heritage Gas purchases natural gas from the M&NP pipeline to supply their customers. This cost is averaged monthly to shield individuals from daily price fluctuations. There is no mark-up on this 'gas cost recovery rate'. Heritage gas then adds a base customer charge and usage rate set by The Nova Scotia Utility and Review Board, in order to cover their costs and profit. The total charge that customers face depends on the volume of consumption. In 2010, on average a residential customer paid a marginal rate of $11.08/MMBtu, commercial users similar to Acadia University or Valley Regional Hospital paid $6.89/MMBtu and industrial users like Michelin paid $5.04/MMBtu[46]. A breakdown of this cost is show below in Table 6; all users pay the same 'gas recovery rate'.

Table 6 Heritage Gas Average 2010 Cost Breakdown

	Fixed Charge $/month	Variable Charge $/MMBtu	Gas Recovery Rate $/MMBtu
Residential	482	6.15	4.93
Commercial	18	1.96	4.93
Industrial	1729	0.11	4.93

Source: Heritage Gas

Only the gas recovery rate component, or commodity price of natural gas, will be used in NPV calculations. The additional charges from Heritage Gas stem primarily from the construction and maintenance of the pipeline network which already are accounted for in the cost section of the analysis.

Heritage Gas 2010 average gas cost recovery rate $\$4.93\,/_{MMBtu}$

[46] Heritage Gas Inc. "Historical Rates," *Heritage Gas Inc*, 2010, accessed Mar. 2, 2011, http://heritagegas.com/historical-rates.html.

3.1.3 Energy Cost Savings

Using a natural gas price of $4.93/MMBtu, a Bunker C price of $12.75/MMBtu and a quantity consumed of 1861 MMBtu/day, the energy cost savings each year is calculated in Appendix A.1.3 to be $5,311,466/year. This amount constitutes an economic benefit in the CBA.

3.2 Pipeline Construction Costs

Of the cost components involved in constructing a pipeline, designing and surveying the route and securing right of way (access to land) increase only slightly with pipeline size and are primarily a function of length. Material costs, particularly steel which can comprise up to half the cost of larger pipelines, increase rapidly with diameter as the thickness of the pipe wall also increases to meet the same structural safety requirement[47]. Construction costs also increase with diameter as more welding and excavation is required and in some regions of the country it is necessary to hire union labour to complete a large project[48]. Pipeline construction costs are a linear function of length and diameter. The size of the diameter is selected based on required flow rates and pressure. Small increases to the diameter yield large increases in capacity making it generally more economic to transport large volumes.

3.2.1 Pipeline Length

The planned Annapolis Valley lateral would run from the Windsor Junction on the Halifax lateral at Miller Lake to Waterville (Figure 4), a length of approximately 105km. One of the major variables in pipeline construction cost is the amount of rock excavation required. While Heritage Gas has been encountering issues with bedrock and shallow topsoil in Halifax, it

---

[47] Canada, National Energy Board. "The Maritimes Natural Gas Market," June, 2003.
[48] Nick Hawkins, email to author. February, 2011.

does not appear to be a concern on the route to the Annapolis Valley based on geological maps from Nova Scotia Natural Resources[49] and consultations with Stephen Rankin of M&NP.

3.2.2 Pipeline Diameter

Recall that 1.81 MMSCFD is the average daily flow requirement as calculated in Appendix A.1.1. Note this is an average based on an entire year of use. Acadia uses over three times more energy in the winter months than the summer months. Michelin's seasonal and daily variation would be lower as it runs fulltime year round. Increased peak demand is important to take into account when deciding on a pipeline throughput capacity as well as providing room for future expansion in the demand base.

Gas pipeline capacity can be calculated based on the diameter of pipe, initial pressure and final pressure. The Halifax lateral reaches its destination with just over 500 pounds per square inch (psi). This can increase when low demand 'backs up' the pipeline, or decrease if demand in Halifax is high. A psi of 100 is sufficient for the Annapolis Valley although facilities like a natural gas power plant or co-generation turbine could require a higher pressure, were one to be built.

Nominal Pipe Size (NPS) is the North American standard for pipelines; it comes in 2 inch diameter increments (i.e. 4 inch, 6inch, 8inch etc.). In Appendix A.2.2 the capacity of several different pipe sizes is calculated.

An 8 inch pipe, still considered a fairly small diameter, would provide 13.5MMSCFD, more capacity than the Annapolis Valley could use, even with peak capacity and room for expansion in mind.

[49] Nova Scotia, Department of Natural Resources, "Mineral Resource Land-Use Maps," 2000. Accessed February 25, 2011, http://www.gov.ns.ca/natr/meb/download/dp047dds.asp.

The capacity of a 4 inch pipe, the smallest you would likely ever run this distance would exceed average annual demand, with a capacity of 2.13MMSCFD, but would leave no room for expansion and could run into issues during times of peak energy use.

A 6 inch pipeline has the capacity for 6.28MMSCFD at these pressures. This would make it a reasonable choice for an area with an initial average annual requirement of 1.81MMSCFD.

3.2.3 Pipeline Cost Estimate

There are various pipeline cost estimation methods used in the industry and literature. The Canadian Energy Pipeline Association suggests $1,000 per millimeter of diameter per kilometer as a rough estimate of pipeline cost[50]. In calculations done in Appendix A.2.3 this estimates the cost of a 6 inch lateral to the Annapolis Valley at $16 million.

A study conducted by the Massachusetts Institute of Technology used natural gas pipeline construction costs that were published in the *Oil and Gas Journal* from 1989-1998 to look at the relationship between pipeline construction costs and other confounding factors such as pipe capacity, materials used etc. The study reported that the cost of pipeline will increase by $33,853 (on average) for every inch of diameter per mile. Adjusted for inflation and converted to Canadian dollars in Appendix A.2.3 this calculation estimates the cost of the project at $15.86 million, very close to the CEPA rule of thumb. $16 million is used for NPV calculations.

3.2.4 Pipeline Annual Operations and Management Costs

FGA Consultants estimate the annual operations and management costs are $2,554 (2002 CAD) per kilometer of the lateral[51]. This will cover the cost of operating and maintaining the

[50] Canadian Energy Pipeline Association "Pipelines 101,". Accessed February, 2011, http://www.cepa.com/pipeline101.aspx?page_guid=05817B59-0D2D-4388-9600-A915F34D1CE7.
[51] FGA Consultants, "Study to Identify the Economic Impacts of a Natural Gas Pipeline to Prince Edward Island," 1999.

pipeline. Total O&M costs are estimated at \$322404/year (2011 CAD). These will be discounted for each future year in the NPV formula (see Appendix A).

3.3 Net Present Value

Recall that the consumption of natural gas is estimated to generate \$5.31 million per year in fuel savings in the Annapolis Valley. Some of this will have to pay for the pipeline construction (\$16 million) and maintenance (\$322404 per year) which are factored in next. The NPV of the project is calculated by discounting the annual net benefits, occuring in the form of fuel savings, back to the current year and subtracting the cost of the pipeline from this value. For example, the NPV of the pipeline's third year of operation, using a 4% discount rate, can be calculated as follows:

$$\frac{(^{\$5,311,446}/_{year} - ^{\$322,404}/_{year})}{(1+.04)^3} = \$4,435,601$$

A detailed yearly breakdown is available in Appendix A.3 and a summary provided in Table 7:

Table 7 Base Case NPV, 2010 Natural Gas price

Discount Rate	NPV	IRR	Break Even
2%	\$65,584,631	31%	4 years
4%	\$51,808,231	31%	4 years
6%	\$41,228,579	31%	4 years

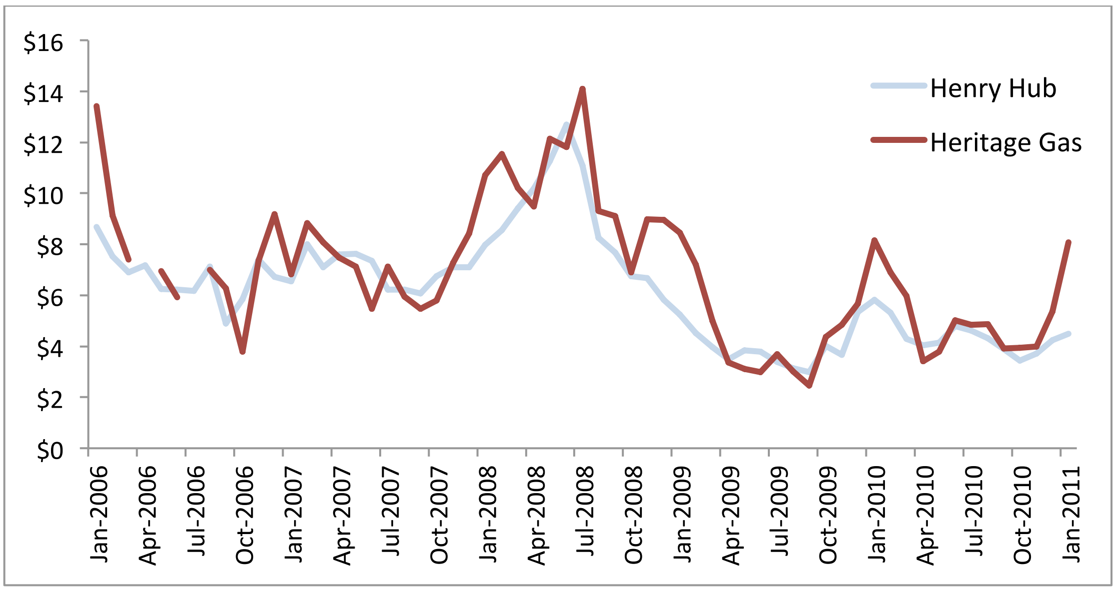
We can see from Table 7 that the project has a positive NPV at all three discount rates. It should be kept in mind at this point that this represents the complete economic surplus and the returns would have to be shared between producers (the pipeline company) and consumers (Annapolis Valley customers). Still the high positive result is so strong that the project should be financially attractive from a commercial standpoint. It raises the question of why the project has not been undertaken.

As mentioned earlier, studies were conducted in similar areas of the Maritimes by Gardner Pinfold Consulting Economists Limited in 2002. These produced weak or negative NPVs because Bunker C was cheaper than natural gas at the time, making few of the large users likely to convert. If those price conditions existed, there would only be environmental reasons for an Annapolis Valley lateral. As such, a sensitivity analysis on the price of natural gas will be conducted in the next chapter.

4 Natural Gas Price Sensitivity Analysis

The historic volatility of natural gas prices combined with the crucial role of the price differential between Bunker C and natural gas raises questions of riskiness of this project. In order to evaluate the feasibility of this project, sensitivity analysis is conducted with regards to various natural gas price forecasts based on historic data. Heritage Gas's gas cost recovery did not have a sufficient history so monthly data was gathered from Henry Hub, a major gas trading junction in Louisiana (U.S.), which is considered an accurate measure in the industry of natural gas prices in North America. Henry Hub prices were adjusted for monthly CAD value to mitigate the effects of exchange rate fluctuations. Finally, after observing that the Henry Hub price and Heritage Gas price were satisfactorily correlated using all available historical data for Heritage Gas (see Figure 13), an average mark-up was calculated. This price variation between the two locations is expected as a result of differing proximity to producers, markets and access to pipeline transportation. Heritage Gas was found to be 12% more expensive on average. Using this average price differential between two gas suppliers and the sample of Henry Hub prices for the 2003-2010 period, the corresponding price of natural gas for Heritage Gas is estimated for the 2003-2006 period.

Figure 13 Historical Natural Gas Prices (Nominal $CDN)



Source: Heritage Gas and U.S. Energy Information Administration

Since there is not a theoretical basis for a normal distribution in the price of natural gas, Chebyshev's inequality was used (which can be viewed in Appendix B) to construct a confidence interval for the price of natural gas. It shows that two thirds of historical prices are likely to be contained within 1.6 standard deviations of the average price.

4.1 Short-term Price History

Natural gas prices have been relatively stable since spiking in 2008 (see Figure 14). Many forecasts see this trend continuing, so a sensitivity analysis was conducted using variation and average price from a 1.5 year history (mid 2009-2010) with results summarized in Table 8.

Table 8 Natural Gas Short-term Price History, 4% discount rate

	Natural Gas	NPV	IRR	Break Even
+1.6σ	$7.45	$28,545,019	20%	6 years
Average Price	$4.91	$51,992,859	31%	4 years
-1.6σ	$2.36	$75,533,014	42%	3 years

Here we begin to see just how powerful the price of natural gas is on the NPV. All three natural gas prices show NPVs that would indicate the project should go ahead. However the highest with a 20%IRR and 'break even' in 6 years, might require government assistance as some of the NPV will be used to entice customers to convert. This would lower the IRR and delay the 'break even' year from a commercial standpoint.

4.2 Medium-term Price Forecast

The U.S. Energy Information Administration has extensive forecasting of Henry Hub prices. The three year (2013) forecast was marked up for Heritage Gas and converted to CAD and a confidence interval provided by data from 2007-2010. NPV was calculated with this confidence interval in Table 9.

Table 9 Natural Gas Medium Forecast, 4% Discount Rate

	Natural Gas	NPV	IRR	Break Even
+1.6σ	$10.47	$666,092	4%	19 years
Forecast Price	$5.34	$48,023,343	29%	4 years
-1.6σ	$0.21	$95,380,595	51%	3 years

The range of the confidence interval shows considerable volatility but all three values show at least a slightly positive NPV. Looking at a project that could result in between \$0.6 million and \$95.3 million of value could be a risk all participants are willing to take. \$0.21 is not a realistic price for natural gas; this confidence interval is simply a result of natural gas having a low median price with large spikes.

4.3 Long-term Price History

Wary customers considering natural gas might take a look at Heritage Gas's January, 2011 natural gas price of \$8.08/MMBtu (well above the short-term history confidence interval) and believe that natural gas is still as volatile as ever. Natural gas prices have dramatically increased several times in the past few years; early 2006 and mid 2008 saw such spikes. The volatility and average price in a, more complete, 7 year history (2003-2010) was examined in Table 10.

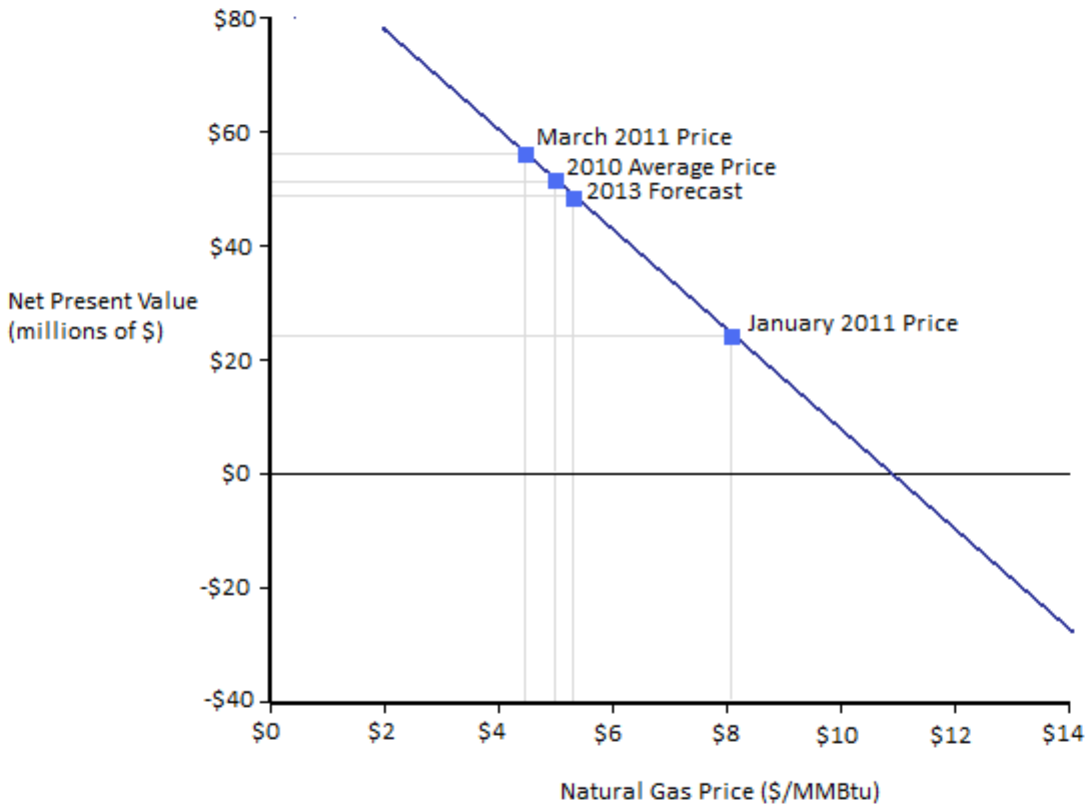
Table 10 Natural Gas Long-term Price History, 4% discount rate

	Natural Gas	NPV	IRR	Break Even
+1.6σ	\$11.37	-\$7,642,198	-2%	
Average Price	\$7.30	\$29,828,734	21%	6 years
-1.6σ	\$3.23	\$67,501,667	38%	3 years

Here we have some interesting results. The price of \$11.37/MMBtu results in a project with a negative NPV that is neither financially viable nor economically justifiable and should not be subsidized. At a price of \$7.30 the project is feasible and should go ahead but may need a government incentive (which could also take the form of a power plant, environmental restrictions or risk reduction). At a price of \$3.23 the project should be viable enough to overcome almost any limitation.

The relationship between natural gas price (price differential) and NPV is linear; a $1 jump in the price of natural gas will cut $9.2 million from the NPV of the project as illustrated in Figure 14.

Figure 14 NPV as a Function of Natural Gas Price, 4% Discount Rate



It's now clear how enthusiasm for the project could vary depending on which of these confidence intervals Annapolis Valley customers put their faith in. Those that remember the natural gas prices in 2006 and 2008 may not want to part with their Bunker C.

5 Environmental Cost

As one of the most polluting fuel choices available, Bunker C carries with it a large cost to the environment. In this section we quantify the social costs (externality) of these emissions, primarily the greenhouse gas CO_2 and acid raid forming SO_2 using the emission taxes implemented in British Columbia and SO_2 'cap and trade' allowance auctions in the United States.

5.1 CO_2

Natural gas has CO_2 emissions that are a third lower than Bunker C, even without taking into account efficiency (Table 11).

Table 11 CO_2 Emissions per MMBtu

Fuel	CO_2 Emissions
Natural Gas	53.06kg/MMBtu
Bunker C	78.8kg/MMBtu[52]

If a carbon tax modeled on British Columbia's were put into place, which could be considered as being levied at a politically feasible level, natural gas would become relatively cheaper. BC's carbon tax rate on natural gas is $0.038/m^3 or an additional $1.05/MMBtu (see Appendix C.1 for conversion). As Bunker C is no longer used by Canadian ships on the west coast and has been largely replaced by natural gas or other alternatives in industry, it is exempt from the carbon tax and other fuel taxes in BC so as not to disadvantage Canadian exports by increasing shipping costs. However its use as an energy source in Nova Scotia's industry would not afford it the same protection and a carbon tax proportionate to its CO_2 emissions can be

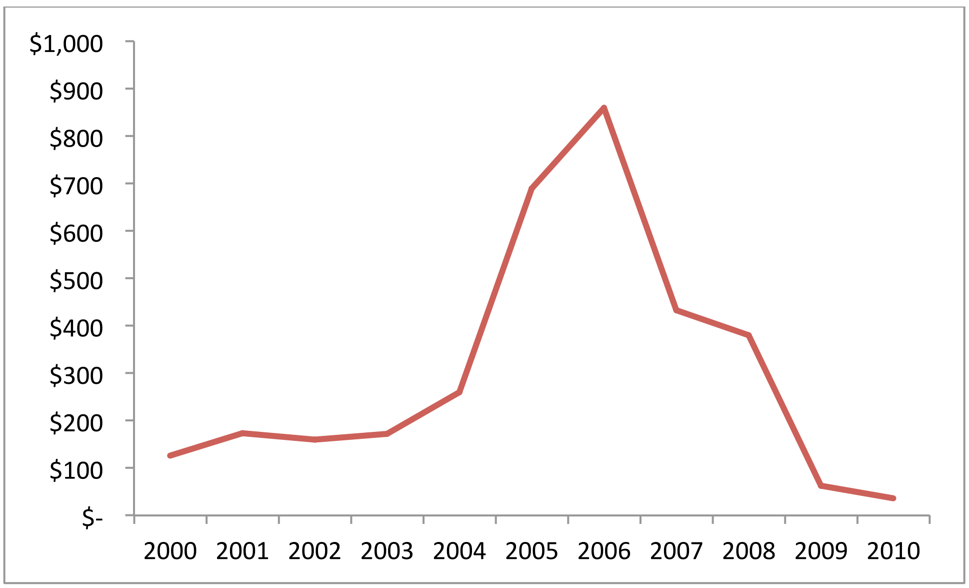
[52] U.S. Energy Information Administration. "Fuel Emission Coefficients," Voluntary Reporting of Greenhouse Gases Program, January 31, 2011. Accessed February 23, 2011, http://www.eia.doe.gov/oiaf/1605/coefficients.html.

derived. Calculations in Appendix C.1 derive an appropriate carbon tax on Bunker C of $1.56/MMBtu.

5.2 SO_2

A cap and trade SO_2 emissions allowance system has been in place in the United States since 1993. The fraction of allowances they reserve for an annual auction can be used to put a price on these emissions (Figure 15).

Figure 15 Clearing Price of SO_2 Allowances ($US/Ton)



Source: U.S. Environmental Protection Agency

The lowest successful bid or 'clearing price' (see Figure 15), in 2010 was $36.20US for the right to emit one ton of SO2 that year[53]. Calculations in Appendix C.2 translate this to the equivalent of an additional $0.02/MMBtu on the price of Bunker C. At current allowance prices the SO_2 emissions from Bunker C do not represent a significant cost. If we instead used the average 'clearing price' (remember this is lower than average winning bid) for 2000-2010, which was $304.85US we get an additional cost to Bunker C of $0.17/MMBtu.

[53] U.S. Environmental Protection Agency, "2010 EPA Allowance Auction Results," March 23, 2010. Accessed February 24, 2011, http://www.epa.gov/airmarkt/trading/2010/10summary.html.

5.3 Incorporating Emissions

Even if these emissions are not taxed, they can still be valued at these estimates of market prices to incorporate the externalities into fuel costs (Table 12) for the purposes of examining the full economic benefit which may be justification for government subsidies to eliminate the use of Bunker C.

Table 12 Fuel Prices ($/MMBtu) Incorporating Efficiency and Externalities

	Natural Gas	**Bunker C**
2010 Average Price	$4.93	$12.14
Additional Costs (5%)		$0.61
CO_2 Externality	$1.05	$1.56
SO_2 Externality	$0	$0.17
Total Cost	**$5.98**	**$14.48**

From these social fuel costs we can generate a NPV (Table 13) that the government or other environmentally minded participants could consider.

Table 13 2010 Fuel Prices, Incorporating CO_2 and SO_2 Externalities

Discount Rate	**NPV**	**IRR**	**Break Even**
2%	$73,137,362	34%	4 years
4%	$58,085,605	34%	4 years
6%	$46,526,538	34%	4 years

Valuing the emission reductions at these levels would add about $7 million to the NPV of the project at each discount rate. However customers and producers would be unable to realize any portion of this as financial gain without government policies that promote natural gas or discourage emissions. Likewise the IRR and 'break even' of the project become more attractive to society, although not necessarily to the pipeline company or customers without targeted government policy. If Michelin, Acadia University or Valley Regional Hospital were to recognize and state that they value the environmental benefits of this project, in effect that they would tolerate to some extent a natural gas price that was higher than that for Bunker C, the feasibility of the project increases.

6 Limitations

This study was performed from an economic perspective which analyzes the economic viability of the proposed lateral. However there are other perspectives outside the scope of this study that must also see the proposed lateral as viable for it to proceed.

6.1 Michelin

As Michelin provides the majority of the 'anchor load', their willingness to convert to natural gas is central to the feasibility of the lateral line. They would also have to consider the risk associated with a long term delivery contract the pipeline company could require. It would expose them to the price fluctuations of the natural gas market as futures will not cover the entire duration. Any long term delivery contract creates a balance sheet obligation Michelin may not be comfortable with. Instead of, or as well as, a long term delivery contract, Michelin could be required to provide a capital cost contribution to the pipeline construction costs. In addition they would have to weigh their own conversion costs, which in conjunction with a possible capital contribution cost could be an investment that is not in line with their financial capacity at the time. These issues: conversion costs, volatile fuel costs, pipeline contracts and capital cost contributions are also relevant to Acadia University and Valley Regional Hospital.

6.2 Nova Scotia

Nova Scotia is seeking to make natural gas available to as many Nova Scotians as possible. It may be dissatisfied with a natural gas pipeline into the Annapolis Valley that directly services three large customers if it does not include plans for a more complete distribution system. A distribution network for residential and commercial customers may have trouble getting off the ground if its biggest potential customers have bypassed it, eliminating a source of revenue necessary to attract distribution companies like Heritage Gas. The province currently does not allow any bypass arrangements in the first 10 years of a franchise.

6.3 Pipeline Ownership

There are two established companies that would consider constructing and operating a natural gas lateral to the Annapolis Valley.

The first, M&NP, is primarily a large scale transmission pipeline company that would review the economics of this pipeline as a standalone project. According to their lateral policy, as long as a lateral meets a test toll, based on the pipeline cost and quantity delivered, they will supply gas at the same price as the rest of the network. This could make the lateral more financially attractive but because these costs are spread to other customers on the M&NP network they do not represent an economic gain for society and were not considered in the study. The anchor load customers in the Annapolis Valley do not provide enough demand to meet this test toll on a $16 million pipeline. This does not mean the pipeline is not feasible, just that M&NP would not build the pipeline for free and charge the mainline toll. A government subsidy, capital contribution from a customer like Michelin or higher transmission cost would be required.

Rough estimates using industry rule of thumb for annual pipeline costs of 18% of the initial construction cost[54] show that this would, in effect, raise the cost of natural gas to the valley by over \$3/MMBtu.

$$\frac{\$16 million * 18\%}{1861 MMBtu/_{day} * ^{365 days}/_{year}} = \$4.24/MMBtu$$ > M&NP Test Toll \$0.60/MMBtu

The other potential owner is Heritage Gas. As a Local Distribution Company (LDC), Heritage gas is a utility that operates from a different business model, targeting the low pressure delivery of gas to industrial, commercial and residential consumers within a franchise area. They would have more interest in connecting additional smaller customers in the Annapolis Valley to the network and may view the anchor load as a way to penetrate a new market area. Revenues from anchor load customers would not necessarily be expected to cover the entire cost of lateral construction. They have their own feasibility tests for connecting residential neighbourhoods and commercial clients which several areas in the Annapolis Valley may pass, that were not examined in this study.

A cursory review of the economic feasibility tests used by both of these pipeline companies would indicate some form of capital contribution from Annapolis Valley customers would be required. Government subsidies have also been used in other Canadian lateral projects[55] or regulatory permission to increase fees on a network to raise the funds (postage stamp toll design).

---

[54] Ron Turner, TransCanada Pipelines, Interview with author, March, 2011.

[55] Gardner Pinfold Consulting Economists Ltd. "Natural Gas and its Impacts on Greenfield Gas Areas." September, 2002.

7 Conclusion

Under current conditions the project shows a positive NPV of $56 million at a 4% discount rate, with a 33% IRR. This NPV provides a clear economic justification for the project and the high IRR suggests it could be financially attractive from a commercial standpoint. Pipeline companies and fuel savings for customers in excess of their conversion costs would each require their share of this NPV and although there appears to be enough to go around, it may come down to appetite for risk.

7.1 Commercial Viability

Built into this NPV calculation is a 4% discount. It was also analyzed at 6% but a commercial study might use a rate of 12% and examine the NPV at 10 years. The NPV still remains positive at $12.2 million in this scenario. A pipeline company would expect revenues that covered not only the construction and maintenance costs, which were in the calculation of the economic NPV, but also debt servicing and return on equity required beyond the analyzed discount rate, taxes, amortization and management. This revenue could take the form of a capital cost contribution from the customers or government, plus a toll on natural gas transmission. Whatever form it takes, the amount a pipeline company would expect, using again the 18% rule of thumb for a rough estimate, $2.5-3 million per year for a $16 million dollar pipeline. Set against an energy cost savings of $5.3 million dollars per year it leaves about half the value of the project for conversion costs and consumer energy savings.

7.2 Energy Cost Savings and Fuel Price Risk

While customers in the Annapolis Valley may be able to grab half the current price differential between Bunker C and natural gas ($12.75/MMBtu and $4.93/MMBtu on average in 2010), they could also find themselves with all the risk. If the price differential remained at the average 2010 level they would be able to save approximately 30% on their heating bills (Table

14). This does not factor in conversion costs but it appears likely the government would assist with these costs given the precedents elsewhere.

Table 14 Estimated Annual Fuel Cost Savings at 2010 Fuel Prices

Customer	Annual Savings
Michelin	$1,780,000
Acadia University	$584,000
Valley Regional Hospital	$292,000

The sensitivity analysis showed just how reactive the value of this project is to price changes. An increase in the price of natural gas to $9.13/MMBtu, a possibility within the 1.6σ range examined in the three and seven year histories, would decrease the IRR to 12%. If the pipeline company has been fully protected in contracts this leaves no cost savings for the customers. If the price then rises beyond that point, customers in the Annapolis Valley may find themselves worse off if bound by contracts although they might retain the ability to use Bunker C to prevent further losses.

7.3 Emission Reduction

The conversion to natural gas would completely eliminate SO_2 emissions for all users. Although the Valley Regional Hospital is not producing as much SO_2 with its mix of Fuel Oil No. 2 and wood chips, this combination still puts out large amounts of particulate matter which would also be eliminated with natural gas. The Annapolis Valley would reduce its CO_2 emissions by

17,500 tons each year (detailed in Table 15), the equivalent of taking over 3000 cars off the road[56].

Table 15 Emission Reductions with a Conversion to Natural Gas

Customer	CO_2	SO_2
Michelin	11,700 tons/year	510 tons/year
Acadia University	3,800 tons/year	170 tons/year
Valley Regional Hospital	1,800 tons/year	low
Annapolis Valley	**17,500 tons/year**	**680 tons/year**

8 Further Research

There are areas outside the study area that could influence this lateral. Additional demand along the lateral from Windsor or new supply from nearby natural gas exploration would add additional utility to the pipeline. Changes in the regulatory environment, particularly environmental restrictions on Bunker C use or permission to lay the pipeline along the shoulder of the highway, should trigger a fresh look at the feasibility of the lateral. The price differential between Bunker C and natural gas remains the economic core and increases to the price of oil or a stable low natural gas price would call for an update.

8.1 Windsor

In 2003 M&NP investigated the development of a 50km lateral towards the Annapolis Valley that would supply a potential natural gas power generation plant in Windsor[57]. This would

[56]U.S., Environmental Protection Agency, "Emission Facts: Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks," April, 2000. Accessed March, 2011, http://www.epa.gov/oms/consumer/f00013.htm.

provide a much closer starting point, halving the distance to the Annapolis Valley, and would vastly improve the economics of the lateral. By the same token Windsor should be interested in connecting to an Annapolis Valley lateral that passed near it. Analysis of potential residential, commercial and industrial customers in the Windsor area could provide additional economic justification of the lateral. The investigation of power generation in Windsor suggests that the co-generation plant at Michelin could be a welcome contribution to the grid.

8.2 Nova Scotia Power

From 2009 to 2020 Nova Scotia aims to increase the amount of electricity generated from natural gas by at least 50% (see Figure 9). Exactly how it plans to accomplish this was not investigated in this study. A power plant is the ideal anchor load for a natural gas pipeline because of the volumes involved. The Halifax lateral was anchored by such a customer, Tuft's Cove Power Plant, able to run its boilers on Bunker C and natural gas it increased its generation capacity with two additional natural gas 50 MW turbines in 2003 and 2005[58]. Minas Pulp and Power with their focus on green energy generation might also be interested in operating a natural gas turbine. As Minas Pulp and Power has not yet converted away from Bunker C as of 2011, their potential as a natural gas customer and natural gas power generator could be reevaluated in the future.

8.3 Residential and Commercial Distribution

The costs of such a distribution system and rates of residential and commercial conversion could be evaluated in further research. This would be based on factors including the market share of each home heating choice in the Annapolis Valley; an electric baseboard heating system is much more expensive to convert to natural gas than a home with an existing propane or

[57] Canada, National Energy Board. "The Maritimes Natural Gas Market," June, 2003.
[58] Nova Scotia Power, "Recovering Waste Heat at Tuft's Cove," Connections Newsletter, November 2009. Accessed February, 2011, http://www.nspower.ca/en/home/residential/customernewsletter/3rdedition/tuftscove.aspx.

fuel oil system. An identification of potential areas of customer demand density could help create a layout of the distribution system and determine costs.

8.4 Highway Right of Way

In 2001 the Nova Scotia government decided not to allow high pressure natural gas lines to run alongside provincial highways. This practice is not common in Canada although not unheard of; natural gas pipelines to Whistler, BC and in Quebec make use of highway right of ways. Safety concerns and potential issues with future road maintenance/repairs were cited[59] but these might be reconsidered if usage becomes more widespread. Using the 'right of way' of the highway, would provide significant (10-15% by some estimates) savings on the construction cost of the lateral[60].

8.5 Natural Gas Exploration in the Annapolis Valley

Corridor Resources is a junior resource company that has developed a natural gas field near Sussex, New Brunswick in the Maritime Shale Gas basin which extends to the Annapolis Valley. In 2003 with the partnership of the Potash Corporation of Saskatchewan (PCS), Corridor Resources developed the field to supply nearby potash mills with natural gas. Then in 2007, with the completion of its lateral line and a gas processing facility, supply of about 30 million cubic feet per day to the M&NP mainline began[61]. This lateral has since encouraged further exploration in the area. GLJ Petroleum Consultants Inc. puts the proven plus probable gas reserves of the wells at 412 billion cubic feet[62]. Assessments of the total shale gas resources in the Corridor field

---

[59] Nova Scotia, Subcommittee of the Whole House on Supply. "Minutes of April 5, 2001". Accessed November 13, 2009, http://www.gov.ns.ca/legislature/hansard/comm/sub-su/h01apr05.htm
[60] Stephen Rankin, interview with author, 2009.
[61] Corridor Resources Inc. "A History of the McCully Field," *Corridor Resources Inc.*, 2008, accessed January 24, 2010, http://www.corridor.ca/operations/mccully-field-history.html.
[62] Corridor Resources, "Reserves Assessment and evaluation of Canadian Oil and Gas Properties," Corporate summary, December 31, 2008. Accessed November 13, 2011, http://www.corridor.ca/investors/documents/Reserves-Evaluation-December-2008.pdf.

are 60 trillion cubic feet, of which roughly 5-20% is generally recoverable[63]. This field provides a ready comparison for shale gas fields near the Annapolis Valley that have 69 trillion cubic feet in estimated reserves[64]; at a 10% recovery rate this would be double the size of the SOEP. Triangle Petroleum Corp. has been exploring the area but failed to find commercial quantities since a significant discovery in 2007 and as capital dried up has decided, along with EnCana, to halt major exploration in the region[65].

If a commercially sized quantity were to be found in the Annapolis Valley, this proposed lateral pipeline might even see its flow reversed as it supplied the study area and then sold the excess to the M&NP. Proximity to a pipeline is a major consideration in selecting exploration sites and any lateral could further stimulate natural gas development in the area.

---

[63] Don Warlick "Gas Shale and CBM Development in North America," Warlick Energy, November 1, 2006. Accessed March 2011, http://warlickenergy.info/oil-gas-articles/gas-shale-and-cbm-development-in-north-america/

[64] Judy Myrden, "Shale Gas Project Over" Chronicle Herald, Feb 24, 2010.

[65] Roger Taylor, "Times tough for N.S. gas projects." Chronicle Herald, Feb 24, 2010.

References

Acadia University. "Strategic Plan for Acadia University: Personalized Education for a Complex World," *Acadia University Board of Governors*, 2006, accessed Feb. 23, 2010, http://board.acadiau.ca/tl_files/sites/board/resources/PDF%20Files/Acadia_Strategic_Plan[2006]3.pdf.

Branan, Carl. "Rules of Thumb for Chemical Engineers: Fourth Edition." Oxford: Elsevier Inc., 2005.

Canadian Energy Pipeline Association. "Pipelines 101,". Accessed Feb., 2011, http://www.cepa.com/pipeline101.aspx?page_guid=05817B59-0D2D-4388-9600-A915F34D1CE7.

Canada National Energy Board. "The Maritimes Natural Gas Market." June, 2003

Canadian Army. "Michelin Tire Plant." *Flickr*. Nov. 27, 2009. Accessed Mar. 6, 2011. http://www.flickr.com/photos/canadianarmy/4332502761/.

CBC News. "Halifax to get natural gas by December." *CBC News Canada*. Aug. 14, 2007. Accessed Jan. 13, 2010. http://www.cbc.ca/news/canada/nova-scotia/story/2007/08/14/natural-gas.html.

Corridor Resources Inc. "A History of the McCully Field." *Corridor Resources Inc.* 2008. Accessed Jan. 24, 2010, http://www.corridor.ca/operations/mccully-field-history.html.

Corridor Resources. "Reserves Assessment and evaluation of Canadian Oil and Gas Properties," Corporate summary, Dec. 31, 2008. Accessed Nov. 13, 2011, http://www.corridor.ca/investors/documents/Reserves-Evaluation-December-2008.pdf.

Dalhousie University. "Dalhousie University switches to Natural Gas." *Dalhousie University Media Centre*. Feb. 14, 2011. Accessed Feb. 20, 2011. http://media.dal.ca/?q=node/104.

Eckerlin, Herbert. "Boiler Operating Costs with Natural Gas and #6 Oil." *Union Gas*. Mar. 27, 2002. Accessed Feb. 28, 2011. http://www.uniongas.com/largebusiness/customerinformation/presentations/ProfEckerlin.pdf.

Efstathiou, Jim and Chipman, Kim. "Fracking: The Great Shale Gas Rush," *Bloomberg News*. Mar. 3, 2011. Accessed Mar. 12, 2011, http://www.businessweek.com/magazine/content/11_11/b4219025777026.htm

EnCana. "Deep Panuke Volume 1 (Project Summary)." Nov. 2006.

Energy Policy Research Foundation, Inc. "The Cost of Banning No. 6 Oil in New York City." *Energy Policy Research Foundation, Inc*. Feb. 23, 2011. Accessed Feb. 28, 2011. http://eprinc.org/?p=714.

ExxonMobil Canada Properties Ltd. "Sable Project Operations Overview." *ExxonMobil*. 2010. Accessed Jan. 24, 2010. http://www.soep.com/cgi-bin/getpage?pageid=1/0/0.

FGA Consultants. "Study to Identify the Economic Impacts of a Natural Gas Pipeline to Prince Edward Island." 1999.

Gardner Pinfold Consulting Economists Ltd. "Natural Gas and its Impacts on Greenfield Gas Areas." Sept., 2002. Available from Atlantic Canada Petroleum Institute.

GE Energy. "Michelin Tire Manufacturing Facility in Italy to Be Driven by GE Energy Aero derivative Gas Turbine Generator." *ThomasNet News*. Nov. 16, 2006. Accessed Feb. 25, 2010. http://news.thomasnet.com/companystory/Michelin-Tire-Manufacturing-Facility-in-Italy-to-Be-Driven-by-GE-Energy-Aeroderivative-Gas-Turbine-Generator-500100.

Harrabin,Roger. "Harrabin's Notebook: Shipping Carbon," BBC News, July 14, 2009. Science and Environment.

Heritage Gas Inc. "Registration of Undertaking for Environmental Assessment: Heritage Gas Amherst Pipeline." *Nova Scotia Environment & Labour Library*. Dec. 3, 2004. Accessed Jan. 26, 2010. http://gov.ns.ca/nse/ea/amherstpipeline/Heritage-AmherstPipeline-PublicNotice.pdf.

Heritage Gas Inc. "Historical Rates." *Heritage Gas Inc*. 2010. Accessed Mar.2, 2011, http://heritagegas.com/historical-rates.html.

Hopper, D., Bonner, F. and Fisher, B.. "Mineral Resource Land-Use Maps," *Nova Scotia, Department of Natural Resources*, 2000. Accessed Feb. 25, 2011, http://www.gov.ns.ca/natr/meb/download/dp047dds.asp.

International Organization for Standardization. "Petroleum products – Fuels (class F) – Specifications of Maritime fuels." *International Standard*, 3rd ed. Nov. 1, 2005. Reference number ISO 8217. Accessed Mar. 2, 2011. http://lib.semi.ac.cn:8080/tsh/dzzy/wsqk/standard/ISO8217.pdf.

Johnson, Jeff. "Valuing Flared Natural Gas." *Chemical & Engineering News* 85 (Sept. 10, 2007). http://pubs.acs.org/cen/news/85/i37/8537notw5.html.

Kershaw, Kristy. "Study: NYC Could Save 188 lives, $5billion per year with Ban of Dirty Heating Oils" heatingoil.com, Jan. 22, 2010. Accessed Feb. 24, 2011, http://www.heatingoil.com/blog/study-nyc-save-188-lives-5-billion-year-ban-dirty-heating-oils/

McPhie, Paul, and Caouette, Anthony. “Heavy Fuel Oil Consumption in Canada.” *Statistics Canada*. Nov. 12, 2009. Accessed Feb. 28, 2011. http://www.statcan.gc.ca/pub/11-621-m/11-621-m2007062-eng.htm.

Mellor, Clare. “Alberta firm buys Heritage Gas.” *Chronicle Herald*, Nov. 4, 2009, sec. L.

Miller, Kristin. “NYC Buildings Burning Residual Fuel Pollute City’s Air.” *heatingoil.com*. Dec. 18, 2009. Accessed Feb. 25, 2011. http://www.heatingoil.com/blog/nyc-buildings-burning-residual-fuel-pollute-citys-air1218/.

Mount Saint Vincent University. “Mount Saint Vincent University goes even greener.” *Mount Saint Vincent University*. Sept. 28, 2010. Accessed Feb. 20, 2011. http://www.msvu.ca/en/home/aboutus/mediacentre/mediareleases/Sept28_2010_2.aspx.

Myrden, Judy. “Shale Gas Project Over” Chronicle Herald, Feb. 24, 2010.

News Inferno. “Fracking Suspended in Quebec Following Release of Government Report,” *News Inferno*. Mar. 9, 2011, Accessed Mar. 12, 2011, http://www.newsinferno.com/fracking/fracking-suspended-in-quebec-following-release-of-government-report/.

Nova Scotia, Subcommittee of the Whole House on Supply. “Minutes of April 5, 2001”. Accessed Nov. 13, 2009, http://www.gov.ns.ca/legislature/hansard/comm/sub-su/h01apr05.htm

Nova Scotia Department of Energy. “$14 Million Allocated for Use of Natural Gas.” *Nova Scotia Canada*. Oct. 10, 2002. Accessed Feb. 20, 2011. http://www.gov.ns.ca/news/details.asp?id=20021010003.

Nova Scotia Power. “Recovering Waste Heat at Tuft’s Cove,” Connections Newsletter, November 2009. Accessed Feb. 25, 2011, http://www.nspower.ca/en/home/residential/customernewsletter/3rdedition/tuftscove.aspx.

Safer, Andrew. “Minas Basin’s green revolution.” *Canadian Consulting Engineer*. Mar., 2010. Accessed Mar. 12, 2011. http://www.canadianconsultingengineer.com/issues/story.aspx?aid=1000364041.

Sempra Energy. “Sempra Energy Unit To Surrender Nova Scotia Natural Gas Distribution Franchise.” *Sempra Energy.* Sept. 24, 2001. Accessed Jan. 24, 2010. http://investor.shareholder.com/sre/releasedetail.cfm?ReleaseID=75747.

Sempra Energy. “Sempra Energy Wins Lucrative Nova Scotia Gas Distribution Project; New System Will Be Largest…” *Business Wire*, Dec. 16, 1999. Accessed Jan. 24, 2010. http://www.allbusiness.com/energy-utilities/utilities-industry-electric-power/6776078-1.html

Taylor, Roger. “Times tough for N.S. gas projects.” *Chronicle Herald*, Feb. 24, 2010.

Techline. “The True Cost of #6 Oil.” Accessed Jun. 18, 2009. http://www.pseg.com/customer/business/industrial/convert/cost.jsp.

The Canadian Press. “Oil leak shuts Nova Scotia tire plant.” *The New Glasgow News.* Dec. 30, 2009. http://www.ngnews.ca/Business/Employment/2009-12-30/article-800334/Oil-leak-shuts-Nova-Scotia-tire-plant/1.

Union Gas Ltd. “Thermal Losses.” *Union Gas*. Accessed Feb. 24, 2011. http://www.uniongas.com/business/gastechnology/productsservices/heating/parasitic/thermal.asp.

United States Energy Information Administration. “Electricity Explained.” *U.S. E.I.A. Independent Statistics & Analysis*. Accessed Feb. 25, 2011. http://www.eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states.

United States Energy Information Administration. “Fuel Emission Coefficients,” *Voluntary Reporting of Greenhouse Gases Program*, Jan 31, 2011. Accessed Feb. 23, 2011, http://www.eia.doe.gov/oiaf/1605/coefficients.html

United States Energy Information Administration. “Natural Gas Explained.” *U.S. E.I.A. Independent Statistics & Analysis*. Accessed Feb. 25, 2011. http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_use.

United States Energy Information Administration. “Oil Market Basics: Demand.” *U.S. E.I.A. Independent Statistics & Analysis*. Accessed Feb, 2011. www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/demand_text.htm.

United States Environmental Protection Agency. “2010 EPA Allowance Auction Results,” Mar. 23, 2010. Accessed Feb. 24, 2011, http://www.epa.gov/airmarkt/trading/2010/10summary.html.

United States Environmental Protection Agency. “Emission Facts: Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks,” April, 2000. Accessed Mar. 17, 2011, http://www.epa.gov/oms/consumer/f00013.htm.

Warlick, Don. “Gas Shale and CBM Development in North America,” *Warlick Energy*, Nov. 1, 2006. Accessed Mar. 2011, http://warlickenergy.info/oil-gas-articles/gas-shale-and-cbm-development-in-north-america/.

Yoon, Thomas. “Blow Away Your Soot,” *Marine Engineer World*. 2010. Accessed Feb. 28, 2011. http://www.free-marine.com/i3eng-sootblower.htm.

Appendix A Methodology

In this Appendix the information needed to complete the NPV formula below is gathered and then an NPV calculated. The time horizon in the study is 20 years.

$$NPV = \sum_{t=1}^{20} \frac{(energy\ cost\ savings_t - maintenance\ costs_t)}{(1 + discount\ rate)^t} - \ initial\ construction\ cost$$

A.1 Benefits

A.1.1 Anchor Load

- **Acadia University**

In 2009 Acadia used 3,686,000L[66] of Bunker C, which translates into daily consumption of fuel oil measured in gallons as:

$$\frac{\dfrac{3686000L/_{year}}{365\ days/_{year}}}{3.78541L/_{Gallon}} = 2667\ Gallons\ of\ fuel\ oil/day$$

This is equivalent to approximately 408 million Btu per day as shown below:

$$\frac{153600\ Btu}{Gallon\ of\ Fuel\ oil^{67}} * \frac{2667\ Gallons\ of\ fuel\ oil}{day} = 409{,}770{,}370\ Btu/day$$

Average daily energy consumption at Acadia University is 409,770,370 Btu or 410 MMBtu

[66] Chief Engineer Charles Mackillop, Acadia University, interview with author, 2010.
[67]Btu value of Bunker C http://www.engineeringtoolbox.com/fuel-oil-combustion-values-d_509.html

- **Valley Regional Hospital**

Annual energy use at the hospital is difficult to measure as they use wood chips as well as fuel oil. With 700 employees, 100 consultants, volunteers and over 1000 patients per day the hospital is about half the size of Acadia University. To roughly estimate daily energy use for the Valley Regional Hospital, Acadia University's daily energy use is halved:

$$\frac{410\ MMBtu/day}{2} = 205\ MMBtu/day$$

- **Michelin**

A Michelin plant in Italy has installed a 43 megawatt natural gas turbine generator which will be in continuous operation with 40% of its electricity production (15.2 megawatts) consumed by the Michelin plant. The gas turbine is used for co-generation (heat and electricity) so this may be underestimating the total energy needs of the Michelin plant.

$$15.2\ megawatts * \frac{3.414\ MMBtu}{1\ megawatt}^{68} * \frac{24\ hours}{day} = 1246 MMBtu/day$$

Alternatively, the Waterville Michelin Plant's energy demands can be estimated by examining data another nearby Michelin plant in Bridgewater, Nova Scotia, which has a similar number of employees[69]. In 1998 their annual energy demand was 350,000 MMBtu[70].

$$\frac{350{,}000\ MMBtu/_{year}}{365\ days/_{year}} = 959\ MMBtu/day$$

[68] Megawatt to MMBtu conversionhttp://www.unitconversion.org/power/megawatts-to-btus-th--per-hour-conversion.html
[69] Waterville Michelin: Number of employees http://www.companylisting.ca/Michelin_North_America_Canada_Inc1/default.aspx.
[70] Gardner Pinfold Consulting Economists Ltd. "Natural Gas and its Impacts on Greenfield Gas Areas." September, 2002.

Since the Waterville Michelin Plant is the second largest manufacturer of tires in North America by output tonnage, using the demand for the Bridgewater Michelin may be too conservative so 1246 MMBtu/day is used for the plant's demand.

If Michelin did choose to install natural gas power generation it could potentially make sense to do so on a scale that would allow them to provide additional power for the regional grid. This would result in significantly higher consumption; the Italian Michelin plant's natural gas generator consumes a total of 3523 MMBtu/day.

- **Average Natural Gas Required**

Adding up the average daily fuel use we get a total of 1861MMBtu/day for the Annapolis Valley. This is converted into a volume of natural gas to assist the pipe capacity calculations in the subsequent section. This is done in the following equation using an energy value for natural gas of 0.001027MMBtu/cubic foot and a metric conversion.

$$\frac{1861 MMBtu/_{day}}{.001027\ MMBtu/_{1\ cubic\ foot\ natural\ gas}}{}^{71} * \frac{1\ cubic\ meter}{35.314\ cubic\ feet} = 51314 MSCMD$$

Note M = Thousand, MM = Million or 'thousand thousand'

0.051314 MMSCMD – million metric square cubic meters per day (annual average)

1.8122 MMSCFD – million standard square cubic feet per day (annual average)

[71] Btu value of natural gas.
http://www.eia.doe.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics

A.1.2 Fuel Cost Comparison

A.1.2.1 Bunker C

Acadia's average 2010 price including delivery was $\$0.4924/_{L}$ for Bunker C. In the equation below this is converted into MMBTu using the conversion factors used previously:

$$\frac{\$0.4924/_{L}}{0.1536MMBtu/_{Gallon}} * \frac{3.78541L}{1\ Gallon} = \$12.14/_{MMBtu}$$

This is then increased by 5% for the additional costs associated with Bunker C use (see Table 2).

$$\$12.14/_{MMBtu} * 105\% = \$12.75/_{MMBtu}$$

A.1.3 Energy Cost Savings

Using a natural gas price of $4.93/MMBtu (average 2010 Heritage Gas commodity price), a Bunker C price of $12.75/MMBtu and a quantity consumed of 1861 MMBtu/day we can calculate the energy cost savings each year.

$$(Price_{Bunker\ C} - Price_{Natural\ Gas}) * quantity\ consumed\ per\ year = \ energy\ cost\ savings$$

$$\left(\$12.75/_{MMBtu} - \$4.93/_{MMBtu}\right) * \ 1861MMBtu/_{day} * \ 365days/_{year} = \$5{,}311{,}446/_{year}$$

A.2 Pipeline Construction Costs

A.2.1 Pipeline Length

The pipeline would run 105km or 65.2miles, this is used in calculating necessary diameter.

A.2.2 Pipeline Diameter

1.81 MMSCFD is the average daily flow requirement. This number does not take into account peak or seasonal demand, or room for future expansion. Gas pipeline capacity can be calculated based on the diameter of pipe, initial pressure and final pressure in the equation below. The Halifax lateral reaches its destination with just over 500 pounds per square inch (psi). A psi of 100 is sufficient for Annapolis Valley needs although facilities like a natural gas power plant or co-generation turbine could require a higher pressure, were one to be built.

$$\text{Gas Line Capacity} = \frac{871 * \text{Diameter}^{8/3} * \sqrt{{\text{Pressure}_1}^2 - {\text{Pressure}_2}^2}}{\sqrt{\text{Pipeline Length}}}$$

In the following equations we calculate the natural gas flow capacity supplied by various sizes of pipe:

$$NPS\ 8\ inch\ pipe\ capacity = \frac{871 *\ 8inch^{8/3} * \sqrt{500psi^2 - 100psi^2}}{\sqrt{65.2miles}} = 13.5MMSCFD$$

$$NPS\ 4\ inch\ pipe\ capacity = \frac{871 *\ 4inch^{8/3} * \sqrt{500psi^2 - 100psi^2}}{\sqrt{65.2miles}} = 2.13MMSCFD$$

$$NPS\ 6\ inch\ pipe\ capacity = \frac{871 * \ 6inch^{8/3} * \sqrt{500psi^2 - 100psi^2}}{\sqrt{65.2miles}} = 6.28MMSCFD$$

A.2.3 Pipeline Cost Estimate

The Canadian Energy Pipeline Association suggests $1,000 per millimeter of diameter per kilometer as a rough estimate of pipeline cost.[72]

$$\frac{\$1{,}000}{mm\ diameter} * 6\ inch\ pipe\ \frac{25.4mm}{inch} * 105km = \$16million$$

A 2003 MIT study of natural gas pipeline construction costs published in the *Oil and Gas Journal* from 1989-1998 found a linear correlation (R^2=0.9363) of $33853 per inch of diameter per mile.

$$\frac{\$33{,}853}{inch\ diameter} * 6\ inch\ pipe * 105km\ \frac{1mile}{1.609344km} = \$13.25million(2003\ USD)$$

Adjusting for inflation[73] and converting to CAD, costs are estimated at $15.86 million, very close to the CEPA rule of thumb. $16 million is used for NPV calculations.

A.3 Net Present Value

Year	Benefits	Costs	Net Benefits (Benefits-Costs)	Discounted Net Benefits (4% a year)	Net Present Value (Sum of DNB)
0		- $16,000,000	-$16,000,000	-$16,000,000	-$16,000,000
1	$5,311,852	$322,404	$4,989,448	$4,797,546	-$11,202,454
2	$5,311,852	$322,404	$4,989,448	$4,613,025	-$ 6,589,428
3	$5,311,852	$322,404	$4,989,448	$4,435,601	-$2,153,827
4	$5,311,852	$322,404	$4,989,448	$ 4,265,001	$2,111,175
5	$5,311,852	$322,404	$4,989,448	$4,100,963	$6,212,137
6	$5,311,852	$322,404	$4,989,448	$ 3,943,233	$10,155,371
7	$5,311,852	$322,404	$4,989,448	$3,791,571	$13,946,941

[72] CEPA, "Pipelines 101," http://www.cepa.com/pipeline101.aspx?page_guid=05817B59-0D2D-4388-9600-A915F34D1CE7
[73] Inflation Calculator. http://www.usinflationcalculator.com/

8	$5,311,852	$322,404	$4,989,448	$3,645,741	$17,592,682
9	$5,311,852	$322,404	$4,989,448	$3,505,520	$21,098,203
10	$5,311,852	$322,404	$4,989,448	$3,370,692	$24,468,895
11	$5,311,852	$322,404	$4,989,448	$3,241,050	$27,709,946
12	$5,311,852	$322,404	$4,989,448	$3,116,395	$30,826,340
13	$5,311,852	$322,404	$4,989,448	$2,996,533	$33,822,874
14	$5,311,852	$322,404	$4,989,448	$2,881,282	$36,704,156
15	$5,311,852	$322,404	$4,989,448	$2,770,464	$39,474,619
16	$5,311,852	$322,404	$4,989,448	$2,663,907	$42,138,527
17	$5,311,852	$322,404	$4,989,448	$2,561,449	$44,699,976
18	$5,311,852	$322,404	$4,989,448	$2,462,932	$47,162,908
19	$5,311,852	$322,404	$4,989,448	$2,368,204	$49,531,112
20	$5,311,852	$322,404	$4,989,448	$2,277,119	**$51,808,231**

Thus we end up with a NPV of $51,808,231 million.

Appendix B Natural Gas Price Sensitivity Analysis

Date	Henry Hub Spot ($US/MMBtu)	Heritage Gas ($CDN/MMBtu)	Canadian Exchange Rate ($US)	Heritage Gas ($US/MMBtu)	Heritage Gas Price Difference
Jan-2010	$5.832	$8.5	0.96	$8.16	139.92%
Feb-2010	$5.32	$7.35	0.94	$6.91	129.87%
Mar-2010	$4.291	$6.23	0.96	$5.98	139.38%
Apr-2010	$4.034	$3.44	0.99	$3.41	84.42%
May-2010	$4.14	$3.83	0.99	$3.79	91.59%
Jun-2010	$4.801	$5.27	0.95	$5.01	104.28%
Jul-2010	$4.627	$5.15	0.94	$4.84	104.63%
Aug-2010	$4.315	$4.97	0.98	$4.87	112.88%
Sep-2010	$3.894	$4.11	0.95	$3.90	100.27%
Oct-2010	$3.434	$4.02	0.98	$3.94	114.72%
Nov-2010	$3.714	$4.03	0.99	$3.99	107.42%
Dec-2010	$4.249	$5.47	0.98	$5.36	126.16%

Since there is not a theoretical basis for a normal distribution in the price of natural gas Chebyshev's inequality was used to compute the number of standard deviations required to construct a confidence interval for the price of natural gas.

$$Minimum\ \%\ of\ included\ values = 1 - \frac{1}{k^2}$$

Where k = # of standard deviations used to construct the interval

For k = 1.6 $60.93\% = 1 - \frac{1}{1.6^2}$

We can see that two thirds of the historical prices are likely to be contained within 1.6 standard deviations of the average price.

Appendix C Environmental Cost

C.1 CO_2

Natural gas has CO_2 emissions that are a third lower than Bunker C, even without taking into account efficiency.

Natural Gas	53.06kg/MMBtu
Bunker C	78.8kg/MMBtu[74]

BC's carbon tax rate on natural gas is $0.038/m^3 which using the equation below is equivelant to an additional $1.05/MMBtu.

$$\frac{\$.038}{cubic\ meter\ natural\ gas} * \frac{1\ cubic\ meter}{35.314\ cubic\ feet} * \frac{1\ cubic\ foot\ natural\ gas}{.001027\ MMBtu} = \$1.05/MMBtu$$

[74] U.S. EIA, "Fuel Emissions," .http://www.eia.doe.gov/oiaf/1605/coefficients.html

A tax on Bunker C proportionate to its CO_2 emissions can be derived by emulating the ratio of the tax on natural gas:

$$\frac{78.8kg \; {}^{Emissions}/_{MMBtu} \; BunkerC}{53.06kg \; {}^{Emissions}/_{MMBtu} \; Natural\ Gas} * \$1.05/_{MMBtu} = \frac{\$1.56}{MMBtu} of\ Bunker\ C$$

Carbon tax on Bunker C $1.56/MMBtu

Carbon tax on natural gas $1.05/MMBtu

C.2 SO_2

Bunker C has 1,122lb of SO_2/Billion Btu The lowest successful bid or 'clearing price', in 2010 was $36.20US for the right to emit one ton of SO_2 that year[75]. Using the following formula we can translate this into a cost per MMBtu:

$$\frac{1\ ton}{2000\ lb} * \frac{1122\ lb\ SO2}{Billion\ Btu\ of\ Bunker\ C} * \frac{\$36.20US}{1\ ton\ SO2} * \frac{1\ Billion\ Btu}{1000\ MMBtu} * \frac{1USD}{0.9897CAD} = \$0.02/MMBtu$$

The average 'clearing price' (remember this is lower than average winning bid), for 2000-2010 was $304.85US. If we use this value instead:

$$\frac{1\ ton}{2000\ lb} * \frac{1122\ lb\ SO2}{Billion\ Btu\ of\ Bunker\ C} * \frac{\$304.85US}{1\ ton\ SO2} * \frac{1\ Billion\ Btu}{1000\ MMBtu} * \frac{1USD}{0.9897CAD} = \$0.17/MMBtu$$

[75] United States, Environmental Protection Agency, "2010 EPA Allowance Auction Results", March 23, 2010. Accessed February, 2011 http://www.epa.gov/airmarkt/trading/2010/10summary.html