Report No. 060516.03

Prepared for:
Halifax Regional Municipality

Community Energy Plan

Task 3 – Future Demand and Supply Assessments

Final Report

November 2007

HALIFAX REGIONAL MUNICIPALITY

Naturally GREEN

CBCL LIMITED
Consulting Engineers

Jacques Whitford

The Sheltair Group

ISO 9001
Registered Company

Table of Contents

Appendices

SETTING THE CONTEXT – FUTURE ENERGY SUPPLY AND DEMAND PROJECTIONS

The Problem

- Energy consumption in HRM has increased by 18% in the past five (5) years.
- The cost of consumed energy in HRM has increased by 40% in the past five (5) years.
- The vast majority of the energy supply in HRM is from imported sources (outside Nova Scotia).
- Current business-as-usual forecasts predict a 10% increase in consumption of energy in the next five (5) years and a 50% increase in the next twenty (20) years.
- Sources of conventional energy are declining worldwide at the same time as the demand for fossil fuels is increasing. Increasing demand and reducing supply is leading to steadily increasing prices.
- Prices for fossil fuels are forecast to increase by between 30% and 60% in the next twenty (20) years.

HRM's Response

- Council has approved the 25-Year Regional Plan which outlines the vision of a sustainable environment.
- HRM has been exploring means to procure greater quantities of its corporate electricity consumption from renewable sources.
- HRM have been developing a green procurement strategy that will ensure that all future procurements must consider sustainability as a key criterion.
- HRM has been expanding access to public transit in order to reduce the number of private vehicle commuting trips and their resultant pollution and energy consumption.

Expected Outcomes

- This deliverable is expected to create greater awareness of the sources of energy used within HRM.
- Future supply availability and cost of some energy sources will impact decisions regarding future development.

1 INTRODUCTION

This report presents the results of the HRM Community Energy Plan (CEP) Project Task 3, Future Demand and Supply Assessments, which reviewed the various aspects of future energy demand within HRM and future energy supply to HRM. The report includes:

.1 Energy and demand projections to 2026.

.2 A forecast of the price of coal, Heavy Fuel Oil (HFO), Light Fuel Oil (LFO), natural gas and electricity per year from 2008 to 2026.

.3 General background information on the Nova Scotia electricity market.

.4 A high level, qualitative review of various risk factors that relate to the supply of energy to HRM.

.5 A summary of future energy supply goals, objectives and actions.

2 FUTURE ENERGY AND DEMAND PROJECTIONS

Demand projections were derived from a number of assumptions and historical considerations. The degree of the forecast accuracy is compromised somewhat when projections are made over a 25-year horizon. To a large extent, the community's future energy requirements are a function of the plan developed by the community's leaders. In this regard, HRM future developments, rural and urban planning, population growth and the demographics pattern have been reviewed in order to make estimates for future energy and demand projections. HRM's 25-Year Regional Plan has been a useful tool from which to anticipate HRM's population size, rate of development and type of settlements that will occur over the next twenty-five (25) years, as well as the level of economic activity that can be expected over this time period.

Apart from the 25-Year Regional Plan, other background materials from HRM's ongoing and completed functional plans were used. Similar to Task 1 of this CEP, the energy and demand profiles for HRM years 1997 and 2002 were those presented in the 2002 Greenhouse Gas (GHG) emissions inventory report that was prepared for HRM by the International Council of Local Energy Initiatives (ICLEI). Observations of trends and indicator changes between these years helped to develop a forecast of what magnitude and direction energy related changes and behaviour could be in HRM in five-year intervals. Therefore, for HRM specific energy forecasts to 2026, for the purposes of this CEP, we used a mixed approach based on the past trends, anticipated increase in economic activity, and HRM's 25-Year Regional Plan.

Table 1 summarizes HRM's residential energy forecast snapshot for 2012 (end of current Kyoto compliance period) and 2026, under the business as usual (BAU) scenario.

Table 1. Residential Energy Forecasts for 2012 and 2026

Indicator Description	2012 (Year of Kyoto target)	2026 HRM Residential Forecast		
		Low Growth	Most Likely	High Growth
Population	397,539	411,090	443,490	487,691
Dwelling Units	197,808	207,100	207,975	208,850
Persons per Household	2.01	1.98	2.13	2.34
Total Residential Energy under BAU, (GJ)	15,357,887	20,351,852	20,904,314	21,456,777
Residential Electric only, (GJ)	6,109,834	7,480,152	7,599,516	7,718,879
Residential Non-Electric, (GJ)	9,248,054	12,871,699	13,304,799	13,737,898
Per Household Average Consumption, (GJ)	78	89	90	92

Forecasts for non-electric energy demand in the Residential Sector, as shown in Table 1, are based on the anticipated population growth rates and household characteristics as outlined in the Regional Plan. Although Nova Scotia Power has provided electricity consumption estimates from 2002 to 2006 within

HRM, these were not broken down into HRM specific Sectors. The Sector breakdown of past electricity consumptions has been based on the province-wide Sector profiles. The HRM residential electricity consumption for 2006 was used as the basis of forecast for future residential consumption.

Table 2 and Figure 1 are HRM Sector profiles of electrical energy use in 1997, 2002 and 2005, and energy forecasts beyond 2005 to 2026, in gigajoules. These forecasts represent a relatively complete picture of the region's past energy consumption, and, on the basis of these trends, the region's future energy usage, assuming there is no significant change in the per capita amounts, and the ways in which energy is used in HRM.

Table 2. Community Electrical Energy Usage and Future Requirements (GJ)

Sector	Past Consumption			Future Projections		
	1997	2002	2005	2007	2012	2026
Residential	4,833,077	5,228,127	5,478,367	5,744,484	6,109,834	7,599,516
Commercial	3,892,636	4,024,606	4,217,240	4,387,617	4,844,284	6,391,929
Industrial	3,604,702	3,826,238	4,009,378	4,106,180	4,358,535	5,150,718
Other (unmetered, municipal)	841,149	910,629	954,215	984,994	1,066,356	1,331,724
TOTAL	13,171,564	13,989,600	14,659,200	15,223,275	16,379,008	20,473,886

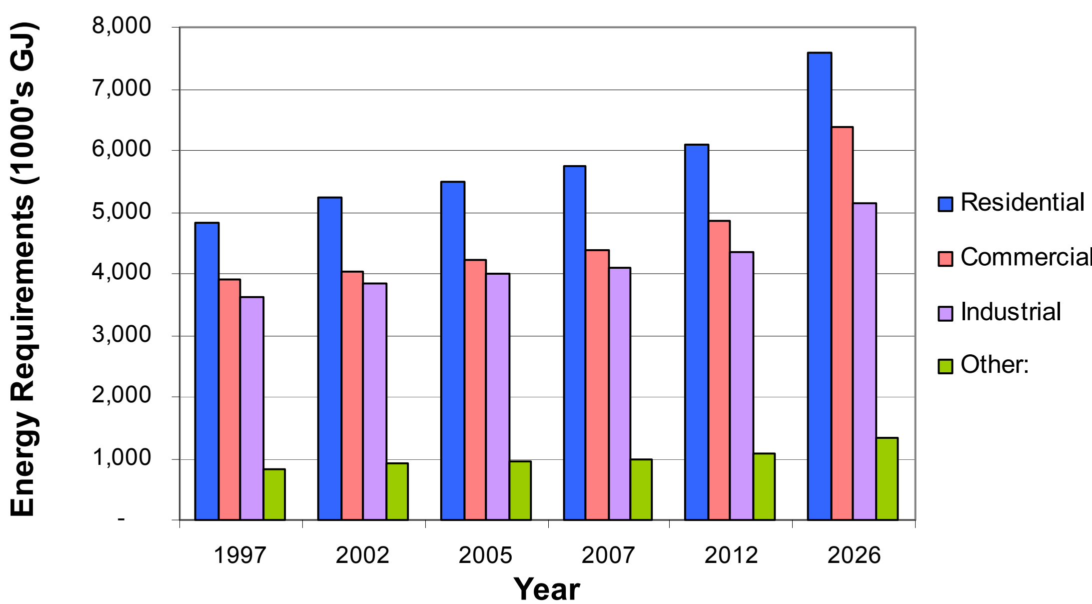


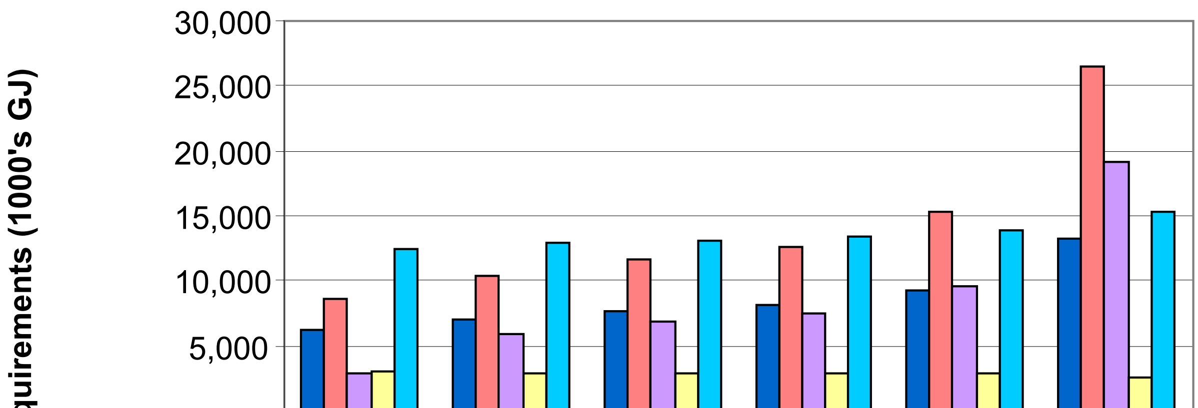
Figure 1. HRM Community Energy Requirements by Sector

Figure 1 presents the same data as Table 2. It is important to note the predicted increase in the energy needs in 2026 to meet the residential activity requirements versus other Sectors. Residential growth is forecast to escalate at about 2.7% annually. If the Residential Sector continues unaltered in it's upwards trend, it would seem likely that the HRM will face serious challenges in ramping up electrical energy supplies to meet these projections. To meet the proposed future requirements, adequate measures will have to be initiated to increase energy utilization efficiencies, implement effective DSM measures and increase supply sources, while ensuring that GHGs and other emissions are in line with GHG reduction targets.

Table 3 and Figure 2 are a depiction of community non-electrical energy forecasts, including the Transportation Sector.

Table 3. Community Non-Electrical Energy Usage and Future Projections by Sector (GJ)

SECTOR	PAST CONSUMPTION			FUTURE PROJECTIONS		
	1997	2002	2005	2007	2012	2026
Residential	6,204,212	7,093,993	7,687,997	8,111,382	9,248,054	13,304,799
Commercial	8,546,115	10,389,197	11,680,728	12,629,764	15,353,538	26,526,842
Industrial	2,837,349	5,919,233	7,312,478	8,419,068	11,974,645	32,111,364
Institutional	3,024,236	2,948,760	2,904,382	2,875,168	2,803,412	2,611,881
Transportation	12,399,101	12,865,735	13,154,103	13,349,931	13,852,349	15,361,999
TOTAL	**33,011,013**	**39,216,918**	**42,739,689**	**45,385,313**	**53,231,997**	**89,916,885**



Year	1997	2002	2005	2007	2012	2026
Residential	6,204,212	7,093,993	7,687,997	8,111,382	9,248,054	13,304,799
Commercial	8,546,115	10,389,197	11,680,728	12,629,764	15,353,538	26,526,842
Industrial	2,837,349	5,919,233	6,852,252	7,554,608	9,641,807	19,090,118
Institutional	3,024,236	2,948,760	2,904,382	2,875,168	2,803,412	2,611,881
Transportation	12,399,101	12,865,735	13,154,103	13,349,931	13,852,349	15,361,999

Figure 2. HRM Community Non-Electrical Energy Requirements (GJ)

Using different forecast approaches, combined community electric and non-electric energy totals are shown in Table 4 for pre-determined periods. Consumptions in the 1997 and 2002 periods are also shown as obtained from the ICLEI Report.

Table 4. Community Energy Projections under Different Forecast Approaches (GJ)

Forecast Approach	1997	2002	2005	2007	2012	2026
Based on BAU Trends	46,182,577	53,206,518	56,938,662	59,744,127	67,278,167	97,369,525
Based on Per Capita Consumption	N/A	N/A	61,057,366	63,173,328	69,205,347	93,750,278
Based on Households Planned in HRM	N/A	N/A	59,919,516	62,035,478	68,067,497	92,612,428

The above discussions have highlighted an array of possible future energy requirement outcomes in the HRM Community.

Corporate HRM accounts for less than 2% of the total region's energy requirements. Figure 3 below shows the forecasted total energy projections for combined Corporate and Community HRM. These projections are the overall energy estimates, while the preceding information is broken down by Sector and, thus may be used for more targeted levels of planning.

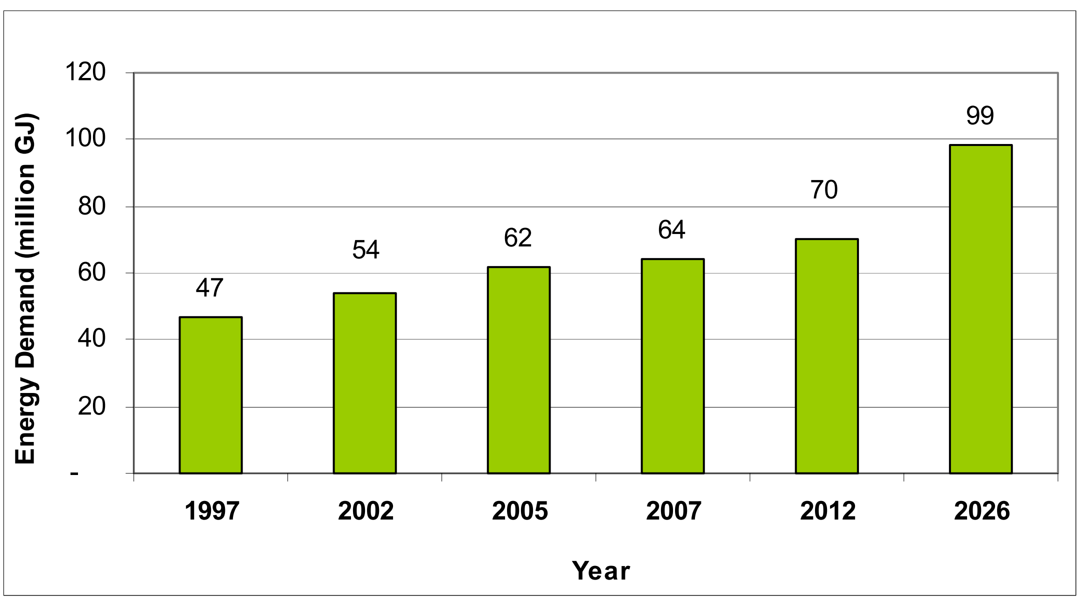


Figure 3. Combined Forecasted HRM Corporate and Community Energy Requirements

3 ENERGY PRICE FORECASTING

3.1 General Basis of Price Forecasting

3.1.1 Introduction

Today, there are large differences even in short term forecasts of energy prices. Analysts predicted prices ranging from $US 60/bbl to $US 80/bbl by the end of 2007. Natural gas prices rose from $US 2.00/MMBtu in 2003 to $US 12.00/MMBtu in 2005. This price increase was unforeseen.

Appalachia Coal prices increased significantly from $US 35/tonne in 2003 to over $US 65/tonne in 2004. It is still in the $US 55/tonne range. The price of coal in both world and North America markets is, to a large extent, unrelated to the price of oil and gas.

Increasing demand for all forms of energy in China, India and Southeast Asia, geopolitical concerns about events in places such as Iran, Iraq and Nigeria, previous hurricane damage in the Gulf of Mexico and continuing demands in the developed parts of the world are all factors contributing to uncertainties and price increases. For example, when China went from being a net exporter of coal to an importer, it had a large impact on world coal trade and prices, including transportation. However, there are large coal reserves in most parts of the world and supply will catch up to demand, thereby reducing these fluctuations.

The prices of oil and sea borne coal are set in world markets, whereas our gas prices are set in the North American markets. These commodities trade in US dollars. This makes the forecast of foreign exchange an additional, significant factor in attempting to forecast future prices for Canadian buyers. The prices referred to in this document are in US dollars, unless otherwise noted.

The differences in what various jurisdictions pay for fossil fuels are functions of transportation costs, the volumes purchased and local taxes. Prices also vary within each fuel type, based on their specific qualities. In fact, commodity spot prices can, and do, vary within most twenty-four (24) hour periods.

There are many companies and institutions dedicated to forecasting the prices of fossil fuels and, not surprisingly, there is not a great deal of consensus on explicit prices. In some cases, even the direction of future price changes is contested. This is the reality of fuel price forecasting.

The conclusion to be drawn is that caution is required when making decisions that are based on forecasted future fuel prices. When trading capital investments against different fuel choices, it would be prudent to undertake sensitivity assessments using a range of future fuel prices, to determine the ranges within which a capital investment might make economic and financial sense. In doing this, one can test the robustness of a decision's ability to withstand a plausible range of futures.

3.1.2 Electricity Price Forecasting

Forecasting the price of electricity generated from fossil fuels can be as difficult as forecasting the price of fossil fuels. First, there is the fuel price forecast. In addition, there are the uncertainties of future load growth (its nature, where and when the load materializes, and the actual demand), environmental regulations and expectations, technological advancements and investments, and fuel switching.

In the Maritimes and New England, fossil fuels are used to generate the largest percentage of electricity. Electricity prices can be expected to track the movements in fossil fuel prices over extended time periods. The earlier increases in electricity prices in the Maritimes and New England and, for that matter, elsewhere in the world, following the rises in the price of fossil fuel, are prime examples of this.

The nature of most electric generating systems is that, with the exception of simple conversions that enable fuel switching, large changes in the capacity mix come slowly. In the short term, a high level analysis of the existing capacity and energy mix within a jurisdiction might enable a rudimentary estimate to be made regarding the impacts of short term fuel price fluctuations on electricity prices.

3.1.3 The US Department of Energy - Energy Information Administration (USDOE EIA)

The USDOE issues various reports on fuels that address matters ranging from economic growth to regional use and pricing. For the purposes of this study, the USDOE EIA "Annual Energy Outlook 2006 with Projections to 2030", dated February 2006 will be used as one of the primary price forecasting tools.

In addition to analysis of its own projections, the EIA also provides a high level summary of the views of several organizations engaged in future fuel price projections. The EIA relies on many assumptions with respect to economic growth, energy demand, fossil fuel production levels, other sources of energy, existing levels of efficiency and environmental regulation, and potential for new regulations and technological development.

3.2 Energy Price Projections

This Section deals with specific projections of future energy prices, based primarily on the USDOE EIA AEO2006 Report.

3.2.1 Assumptions and Caveats

.1 Projections of world and North American fuel prices by EIA are for a short-term continuance of existing prices through 2007, and a softening of increases into the future.

.2 The relationship between crude oil and its derivatives, Heavy Fuel Oil (HFO) and Light Fuel Oil (LFO), have a relatively consistent history, and might reasonably provide some basis for projection of those prices based on crude prices.

.3 The price of natural gas in Nova Scotia is directly related to the New York Mercantile Exchange Henry Hub price. Depending on the gas supply, demand balance and pipeline capacity utilization, Nova Scotia gas prices (at the transmission level) can vary from the Boston City Gate price, to a price at Goldboro that equals the Boston price less the full M&NP pipeline transmission tariffs.

.4 The price of natural gas is likely to continue to be quite volatile, but the projected trend is for a reduction in real prices from the recently past highs, based in part by expectations of new supplies, including LNG.

.5 The Nova Scotia price of HFO can be related to the price for US imported crude oil, as projected by EIA. Those prices are averages, and the prices of HFO derived are, thus, averages. There can also be differences in HFO prices based on sulphur content and other properties.

.6 The Nova Scotia price of LFO can also be related to the price of imported crude, and some volatility can be expected.

.7 The price for electricity, as it might be related to fuel prices, at least for the short term, can be approximated from the energy mix of the NSPI generation, and the cost structure of NSPI.

.8 No fuel price projections are guaranteed, and it is up to the decision maker to recognize the risk, and provide for risk mitigation in the decision making processes.

3.2.2 Forecasted Annual Energy Prices

Table 5 presents selected data from the "US Energy Prices: Base Case" of the previously noted EIA Report.

Table 5. U.S. Energy Prices: Short Term Base Case

FUEL	2005	2006	2007
Imported Crude Average ($US/bbl)	48.95	56.76	53.60
West Texas Intermediate ($US/bbl)	56.49	63.74	60.63
Wholesale Heating Fuel (LFO) ($US/Litre)	0.43	0.46	0.44
No. 6 HFO ($US/Litre)	0.28	0.31	0.30
Henry Hub (NYMEX) Gas ($US/MMBtu)	8.98	8.11	8.74

Table 6 presents a summary of energy price projections for Nova Scotia. These energy price forecasts were produced using an empirical model developed and owned by KnAP Energy Services, which uses the previously noted EIA report as one of its primary inputs (KnAP was one of the sub-consultants used on this project). Recent appreciation of the Canadian currency may change this forecast slightly.

Table 6. Forecasted Delivered Energy Prices

Year	Predicted Foreign Exchange Cdn$/US$	Coal US$/ MMBTU	HFO US$/ MMBtu	LFO US$/ MMBtu	Natural Gas US$/MMBtu	Electricity Large General Rate Cdn$/kWh
2008	1.12595	2.36	7.36	12.57	9.97	0.083
2009	1.11830	2.42	7.16	12.25	8.95	0.084
2010	1.11155	2.48	6.96	11.90	8.52	0.085
2011	1.10480	2.55	7.10	12.15	8.73	0.087
2012	1.09830	2.61	7.24	12.39	8.94	0.089
2013	1.09180	2.67	7.39	12.65	9.16	0.091
2014	1.08547	2.74	7.54	12.91	9.38	0.094
2015	1.07913	2.81	7.70	13.17	8.72	0.096
2016	1.07280	2.88	7.96	13.62	9.03	0.098
2017	1.07280	2.95	8.23	14.09	9.37	0.101
2018	1.07280	3.03	8.51	14.57	9.71	0.104
2019	1.07280	3.10	8.80	15.06	10.07	0.107
2020	1.07280	3.18	9.10	15.57	10.25	0.111
2021	1.07280	3.26	9.45	16.17	10.63	0.114
2022	1.07280	3.34	9.81	16.78	11.03	0.118
2023	1.07280	3.42	10.19	17.42	11.45	0.122
2024	1.07280	3.51	10.57	18.08	11.89	0.126
2025	1.07280	3.60	10.97	18.76	12.31	0.130
2026	1.07280	3.69	11.34	19.38	12.78	0.134

4 THE NOVA SCOTIA ELECTRICITY MARKET: BACKGROUND INFORMATION

This Section of the report is intended to provide some general background information on the complex Nova Scotia electricity market, to provide the reader with a better understanding of the current situation and issues, and with some of the thinking on potential future changes in this market. Additional information is presented in Appendix A.

4.1 General Market Background Issues

Currently, electricity consumers at the retail level have the following options in Nova Scotia:

- buy from NSPI;
- self generate with back up from NSPI; and
- improve energy efficiency.

Wholesale purchasers of electricity (to date only the Municipal Utilities (Munis) qualify), in addition to the above, have the option of buying from other than NSPI. Independent Power Producers (IPPs) selling to the Munis, or to the export market outside Nova Scotia, need to apply NSPI's Open Access Transmission Tariff (OATT) in order to do this.

It is likely, in the foreseeable future, that the large retail customers that are served from the transmission grid will have the same purchase options as the wholesale customers, as is currently the case in New Brunswick. This would likely be followed by the larger users that are served from the distribution system. Ultimately, it is predicted that all end-users will have the choice to select their energy providers.

The issues become more complex as the market moves from one supplier to many suppliers. Future direct sales by IPPs to retail customers further increase the complexity, and will require more regulation and oversight by government and, presumably, the Nova Scotia Utility and Review Board (UARB). A major issue is the accountability for reliability.

While it may be argumentative, in general, in some jurisdictions open access has potentially greater value to generators than to consumers, whereas, in others the reverse might be the case. For example, in areas with low cost generation, if generators have access to higher priced markets, they will sell to those markets, and in effect, the prices of the higher cost markets are exported to what had been previously a lower priced market, and vice versa.

In an extreme case, if the transmission grid were infinite in capacity, electricity prices in a fully competitive North American market would be the same everywhere, higher in formerly low cost areas, and lower in previously high cost areas. It is for this reason that many jurisdictions have determined that existing utility generation should be considered heritage assets, and preserved for the benefit of existing utility customers for whom the asset base was initially developed.

4.2 The Existing Electricity System in the Maritimes

4.2.1 Summary

The Maritimes Interconnected system has a peak demand of approximately 5,700 MW and an annual energy production of about 30,000 GWh. The Maritimes generation mix is quite diverse, which should contribute somewhat to long term price stability. Fossil fuels drive costs and prices in all jurisdictions in Northeastern United States and Eastern Canada.

The potential sources of out of province electricity purchases by Nova Scotia are New Brunswick, Quebec and New England, all of which require access to the NB Power system. The New Brunswick System Operator (NBSO) is the lead operator for The Maritimes and Northern Maine. New Brunswick has interconnections with neighbouring systems and OATTs exist in all jurisdictions "within reach" of Nova Scotia, so customers in NS could purchase from outside the province (except from PEI because PEI does not yet have an OATT).

4.2.2 Maritimes Transmission Interconnections

The Maritimes transmission interconnections are summarized below.

There are various conditions attached to the ratings at any particular time, depending on system configuration. The following table shows "normal" conditions.

Table 7. NBSO Interconnections Ratings in MW

	Existing		with 2nd NB-NE Tie Line	
	Export	Import	Export	Import
Quebec	800	1,200	800	1,200
New England	700	100	1,000	400
Nova Scotia	300	350	300	350
PEI	200	200	200	200

The cost of firm transmission access is summarized in the following Table.

Table 8. Rates for Service Under Northeast Open Access Transmission Tariffs

Network Service Tariffs $/MW/mo			
	Price	Status	Losses
New Brunswick	≈ $30,000	approved	3.3%
Quebec	≈ $73,000	approved	5.2%
New England	≈ US $18,000 – $27,000	approved	
Nova Scotia	≈ $47,000	approved	3.2%
PEI	NA	NA	

Even if capacity were available, the transmission tariffs can be a deterrent to the purchase of low capacity factor peaking generation.

4.3 Overview of Electricity Purchases

The following is a high level overview of the nature and costs of potential electricity purchases from outside Nova Scotia.

Fossil fuels are commodities. From HRM's perspective, the prices of oil and coal are set in world markets, and gas in North American markets. Except for transportation differences, the wholesale costs are the same everywhere.

In addition, one must be aware that, in competitive markets, price volatility is a reality. When commodities are scarce, prices increase. During January of 2004, when power demand was high, marginal prices varied by a factor of almost five times. The high prices of January 2004 are not indicative of a market with a large surplus of cheap energy.

Fuel transportation aside, the marginal costs of energy for each source are virtually the same across NA and, for a given fuel, except for modest efficiencies in economies of scale, the costs of electricity from new plants will be similar. Regional differences might arise from different environmental and operational regulations, and from installed generation mix.

The attractiveness of external purchases, in the absence of environmental emissions constraints, is reasonably reflected in the relatively small quantities and relatively high costs of recent purchases by NSPI and NBP. NSPI purchases from the grid when the purchase price is lower than the cost of self-generation, or when due to outages, short term purchases are required to maintain a secure electricity supply for the province.

Merchant generators seek to maximize their return, and they price their product accordingly. What this would imply for a long term capacity purchase is a price based on the alternatives that the merchant generators or brokers perceive a potential customer might have. This, of course, would be the principal subject of negotiations. Firm energy always costs more than non-firm energy.

5 ENERGY SUPPLY RISK REVIEW

This Section of the report identifies some of the principal risk factors in HRM's energy supply system, and provides an overview of each of these risks. The risk factors addressed during the study were:

- electricity security;
- electricity adequacy;
- other energy dependability;
- transmission and transportation;
- environment (number of different factors);
- monetary; and
- regulatory.

This review is qualitative only, and is intended only to provide information on the extent of potential risk posed by each of the risk factors.

5.1 Security of Electricity Supply

5.1.1 Risk Definition

The criteria related to security of electricity supply, particularly at the generation and bulk transmission level, is the ability to continuously supply the system peak load requirements during a single major system failure, such as a failure of a single transmission circuit, loss of a single generating unit, etc. This is the condition imposed by the Northeast Power Co-ordination Council's (NPCC) "n-1" criteria, that a power system be sufficiently secure to withstand a single contingency occurrence, i.e. a single major problem can occur without loss of power to any part of the system.

Although not NPCC criteria, the risk related to security of supply must also consider the reliability of the electrical distribution system, mix of fuels being used, and supply diversity in general.

5.1.2 Analysis

.1 First and foremost, Nova Scotia Power, being a regulated utility, is obligated by legislation to meet the electricity needs of Nova Scotia, and to meet the NPCC's n-1 criteria.

.2 The electrical transmission system throughout Nova Scotia is very reliable, meeting all current required standards. Loss of any single transmission line supplying HRM will not normally result in loss of power to HRM, as an alternate supply source would be available. Similarly, loss of a single generating unit at Tuft's Cove Generating Station (TC), or any other generating station in the province, will not cause loss of power to HRM.

.3 The electrical distribution system within urban HRM is very reliable, as there are back-ups to virtually all of the main feeders (with manual switching, which may result in some downtime to accommodate switching of feeders). The system is not as reliable in rural HRM, as the same level of back-up does not exist because it would be cost prohibitive, relative to load density, to do so.

With memories of the extensive damage inflicted to the HRM electrical distribution system by Hurricane Juan and "White Juan" still fresh in the minds of most HRM residents, many would likely question the reliability of the system. However, the impact of such catastrophic events cannot possibly be planned into system reliability measures, due to the very low frequency of such an occurrence. The only way to counter such events is to assure that adequate emergency back-up generation is installed at all facilities that provide emergency services.

In terms of distribution system maintenance, detailed information has been recorded by NSPI for many years, tracking frequency and duration of line and customer outages. NSPI prioritizes their annual maintenance budgets on the basis of these statistics, assuring the annual budgets are utilized to correct the most probable problem areas. NSPI can predict with some accuracy where the serious problem spots are likely to be on an annual basis, and can attempt to correct these potential problem areas before they actually manifest themselves into real problem causing outages.

HRM's electrical distribution system overall has significant diversity and flexibility, appears to be appropriately maintained, and is considered to be relatively reliable. Increasing the percentage of the future distribution system that is installed underground would further increase reliability.

.4 In terms of fuel mix, the diversity of supply that generally comes with an optimized mix, **and in strict consideration of electricity supply security with no other criteria applied**, the current security of electricity supply to HRM is as good as it can be for the foreseeable future.

The primary fuel currently used to generate power in Nova Scotia is coal, followed by heavy fuel oil (HFO), with some hydro, gas and renewable energy also contributing to the total mix of generation in NSPI's system. There are many environmentally related reasons to reduce the amount of coal fired generation in this province, **but strictly from a security of supply perspective**, coal is the most secure, reliable fuel for the system. There are abundant quantities of coal in the world, most of which are not impacted by geo-political issues; it is easily and readily available; it is very price stable, relative to other fuels such as oil and natural gas; it is easy to transport and store; and all of the commercial technologies are historically proven and very reliable.

If clean coal burning technologies, such as integrated gasification combined cycle (IGCC), become fully commercially proven and available, coal will be considered as a viable option for the future, relative to supply security. Development of feasible carbon sequestration technologies could also render more conventional coal burning technologies environmentally acceptable in the future.

.5 Natural gas will be the most likely fuel choice for any new, large scale power generation plant built in the province in the future. Due to the current lack of back-up gas supplies in Nova Scotia, increasing diversity by using significant amounts of gas has some, albeit low, potential of causing a reduction in the security of electricity supply. An outage to the Sable gas supply will require that gas be supplied from U.S. sources, and if there is any chance that these might not be readily available, then the risk increases.

Gas fired distributed generation for peninsula Halifax and other specific locations within HRM is a sound objective. However, for the immediate future, any such facilities that are sufficiently large should be designed such that light fuel oil (LFO) can be used as a back-up fuel to counter potential gas supply disruptions. For smaller facilities, this is of less importance, because the grid back-up will always be there. These gas issues are further discussed in Section 5.3.

.6 A commitment to add as much renewable and clean alternative energy to the supply mix as practically and financially feasible is an integral part of this CEP. With respect to the role that renewables/alternatives will play in the security of supply, we have the following comments:

- There is little potential for renewable energy generation within urban HRM, except for the use of solar heating systems and process heat recovery to reduce electrical demand, which of course, reduces the amount of generation required. Photovoltaic installations can provide some self generation potential, but the high capital cost makes them non-commercially feasible without significant subsidies.
- There is potential for the installation of additional wind energy generation in rural HRM, but wind energy is not dispatchable by NSPI, and cannot be relied upon as a back-up energy source in the case of loss of base load generation. Therefore, for the foreseeable future, wind energy will have little or no impact on the security of supply. Wind energy also does not contribute to the reduction of conventional generation on the system, as there currently is little capacity recognition for wind energy systems. However, integration of wind energy systems into a grid that is based on dispatchable thermal plants will not decrease energy security, since the thermal plants will continue to provide backup, and the wind energy systems will reduce the consumption of fossil fuels and the associated emissions.
- There is also potential for other renewable energy generation within rural HRM, using such sources as biomass, biogas, solar, small hydro, etc. It is recommended that, where feasible, the use of these renewable sources be maximized. However, the aggregate energy produced from these sources will be tiny relative to the capacity of the grid, so the impact on security of supply will probably be modest, at least in the short term.

5.1.3 Conclusions

Our analysis of the risks related to security of electricity supply produced the following conclusions:

.1 The n-1 criteria at the transmission and generation level, where it primarily applies, is met with the current system.

.2 Future renewable energy generation will have no material impact on security of supply in the near term (say, five to ten years).

.3 All else being equal, in general, the greater the diversity of supply, the greater the security and price stability (a diversified energy portfolio approach). However, currently in HRM, and Nova Scotia in general, all else is not equal. It may be contentious, but currently our highest security and stability of supply resides with coal. As new sources of natural gas emerge and more renewable energy generation is made available, this will change, but right now, and for the foreseeable future, a more secure, reliable supply system than the one which we currently have in place would be difficult to achieve.

5.2 Electricity Adequacy (or Adequacy of the Current Electrical System)

5.2.1 Risk Definition

This risk factor interlocks significantly with the previous one, but focuses more on risk from a technology and generating plant infrastructure perspective, therefore, a separate review of this risk factor was performed. It addresses the capability of the technical resources available within the province's electrical system to meet the forecasted energy supply and peak demand needs, on a continuous basis. It addresses load versus generation, and the resultant ability to be able to supply the firm (non-interruptible) load of the province.

The NPCC criteria for electricity adequacy limits the risk to a Loss of Load Expectation of one (1) day in ten (10) years. In other words, the loss of generation for one (1) day in ten (10) years would be of such an extent that part or all firm load (i.e. load that is not on the NSPI Interruptible Load Rate base) would have to be shed. This means that there would not be enough generation on the system to supply all of the firm load after the interruptible customers have been shed.

5.2.2 Analysis

.1 Regarding the adequacy of equipment in NSPI's generating stations, all equipment is maintained on a regular basis in accordance with a rigorous preventative maintenance program, which includes overhauls at certain specified intervals, and replacement before age and/or deterioration causes reliability problems. Therefore, the equipment is very reliable, with a very low risk of failure during normal operations. There is always a risk that equipment could fail due to unpredictable, and usually unpreventable, system problems, but in such cases there is normally sufficient back-up within the system to maintain the NPCC criteria.

Information received from NSPI indicates variations in HRM peak demand over the past five (5) years from 751 MW to 858 MW, with 2006 having the second lowest peak demand at 752 MW. These demand fluctuations relate primarily to weather conditions as opposed to actual load increase, meaning that there has been little load increase that has impacted peak demand over the past five years. If it is assumed that this trend will continue for the immediate future, it can also be assumed that, from HRM's perspective, there is adequate existing generating capacity on the system to handle at least its immediate future needs, and the current generation equipment is adequate.

However, as the mix of NSPI/IPP generating capacity changes in the future, a point may be reached where the non-dispatchable IPP capacity will be high enough that it will be needed to meet peak load requirements, i.e. NSPI no longer will be able to provide all of the firm load requirements of the province from its own equipment. Regulatory changes will be necessary for this to happen, because if not, NSPI will be obligated to maintain enough capacity to supply all of the load all of the time. However, regulatory changes are inevitable. In this scenario the risk may change, because all IPPs may not invest in rigorous maintenance programs.

Wind is the only renewable energy that has the potential to have a material effect on the operation of the system. Presumably, because wind is not dispatchable, NSPI would need to maintain enough operating capacity to provide a yet to be determined percentage of back-up to Nova Scotia based wind energy generation, so wind turbine equipment failure should not pose any additional risk. Wind energy can pose a stability risk to the system, however, if the level of penetration of wind energy becomes large. It can be assumed that the proper assurances will be put in place to prevent such problems from occurring.

.2 The other issue regarding adequacy relates to load shedding. Management of this requires a sophisticated load shedding scheme to assure that the maximum firm load remains energized, should system overload occur when a base load generating unit(s) is out of service, or a system problem occurs which causes one or more of the units to shut down. NSPI has such a system, which sheds load as follows in such occurrences:

- In a slowly evolving capacity shortfall, the interruptible loads are shed first, to the amount of total load needing to be shed. These loads are substantial, and for the majority of system events, shedding these loads solves the problem.
- If time permits, designated non-critical loads will be shed next in an orderly manner.
- If there is a catastrophic problem on the system, there may not be time for the orderly shedding of non-critical loads. In this case, automatic system devices take over, and cause loads to be shed automatically, with relatively even load shedding distribution of non-critical loads province wide.
- Critical loads will not be dropped by under-frequency load shedding systems, but may lose supply if the system is stressed beyond the ability of load shedding systems to preserve system integrity or, of course, due to local supply problems.

To avoid even a partial shedding of firm (non-interruptible) load, NSPI will also purchase power across the tie line with New Brunswick, to the extent that this is possible.

A second 345kV transmission line is being built between New Brunswick and North Eastern US for operation by year end. This will increase the transfer capabilities between N.B. and N.E. from

300 to 400 MW. The decision to construct the line is based on economics, but will improve security for both New England and The Maritimes.

When a second 345 kV tie is built between New Brunswick and Nova Scotia security will improve, but again, a decision to build a second tie must be based on economics. All else being equal, greater transmission capacity means greater security.

5.2.3 Conclusions

.1 The NPCC criteria is being met.

.2 Relative to adequacy of equipment, power outages are very rare, and normally power is restored within minutes, to at most, a day. The risk to HRM is very low, but under any circumstances, other than having on site backup supply to critical loads, there is nothing more that HRM can do to mitigate this risk.

5.3 Other Energy Dependability

5.3.1 Risk Definition

"Other energy" refers essentially to fuel oil, motive fuels and natural gas. Our major focus is natural gas.

The major risk regarding fuel oil and motive fuels relates to transportation, which is discussed in Section 5.4, and source of supply, which is primarily the Imperial Oil Limited (IOL) refinery in Eastern Passage.

Relative to natural gas, only a slight risk is driven by the lack of Nova Scotia based gas supply back-up at this time due to the ability to supply gas from Western Canada via existing pipeline infrastructure when disruptions in the supply from offshore Nova Scotia occur. There is only a single main pipeline, a single lateral to HRM, and there will be only a single pipeline across the harbour to peninsula Halifax later this year. A significant problem causing a failure of any one of these lines would disrupt gas supply to all or part of HRM although that is considered highly unlikely given the service record of other pipeline infrastructure in North America.

There are no criteria similar to those of NPCC to benchmark these risks.

5.3.2 Analysis

.1 With respect to supply of fuel oil and motive fuels, disruption of this would require an unplanned shutdown of critical sections of the IOL refinery, due to a major problem(s) there. This is unlikely, although it is certainly not impossible. The impact of the disruption would depend on the length of the outage at the refinery, and the amount of fuel storage that the refinery and the fuel retailers had at the time. The back-up would be the Irving refinery in Saint John, New

Brunswick and the risk would then be driven by the ability of the Saint John refinery to handle the extra demand.

.2 The risk associated with the disruption of natural gas supply is somewhat higher. Currently, there are seven principal components within the natural gas system supplying HRM, with no local contingency for any one part. Therefore, any one of the seven could shutdown the gas supply to HRM for varying periods of time.

The lowest risk components of these seven appear to be the pipelines. Significant safety factors are built into these lines, and once installed and commissioned, nothing much can go wrong. Related pipeline infrastructure such as compressor stations, metering and transfer stations, etc., are also very reliable, with considerable redundancy built in. Therefore, we feel that the risk associated with the pipelines is quite low.

The two onshore plants are also reliable, with much installed redundancy. However, an outage to critical systems at either the gas or liquids plant could result in a field outage. Also, the liquids plant relies on rail and ocean transportation to move its three products, and although there is some storage, it is limited to a regular shipping routine. If this were disrupted for extended periods of time, this plant would have to shutdown, and if the liquids from the gas plant cannot be fractionated and shipped, this plant would only be able to operate for a short time also, and gas supply from Sable would cease until the problems were resolved.

The biggest risk component is offshore production. The Sable gas supplies are slowly decreasing, and although the permitting and procurement phases are on-going, Deep Panuke is still several years away from production. No other local development is poised to come on-stream within a time frame that would alleviate this situation.

There are six offshore facilities, the original three, Thebaud, Venture and North Triumph production platforms, the more recent Alma and South Venture platforms, and the most recent Thebaud compression platform. A shutdown of any of the latter five would result in lower production rates, and a shutdown of Thebaud, or critical systems on Thebaud, would halt production until the problems were rectified. Each of these facilities is very reliable, built for purpose relative to operating in a harsh environment, with significant redundancy, and with a high performance record. They are excellently maintained. However, they do contain many complex, sensitive systems housed within a very small footprint and, as with any other processing facility, failures are possible.

The actual overall risk associated with the loss of gas supply is difficult to quantify. In discussions with representatives from Maritimes and Northeast Pipelines (MNP), Heritage Gas and Enbridge Gas, a general, qualitative understanding of this risk has been developed. The MNP pipeline system is designed such that it can transport gas from either direction (from Sable south to North Eastern US and from N.E. US north to Atlantic Canada markets) with relatively fast turnaround. Assuming the local gas distributor can contract gas supplies from other sources, MNP should be able to reverse direction of flow in the pipeline, and supply the local market from these other sources, within a day or so. The line pack (the volume of gas that fills the pipeline) should be adequate to maintain supply until MNP can switch to the alternate source(s), and commence the flow of gas from south to north. We have been told that this has been tried and proven during several occasions already, when planned offshore outages have been necessary to accommodate the tie-ins for the Thebaud compression platform.

In summary, the system risks, relative to the ability to deliver gas to the Nova Scotia market from somewhere, are relatively low. However, the extent of the security of supply, from the perspective of continuous, expedient availability of gas from other gas suppliers, is unknown. Highly respectable industry representatives have made assurances that this will not be a problem, but we have no means to confirm this.

5.3.3 Conclusions

.1 The risk of a major failure at the IOL refinery, that would cause a significant disruption to the supply of fuel oil and motive fuels is very low, and the risk can be mitigated by using the Irving and other refineries as a back-up source.

.2 Utilizing natural gas for heating and power generation is more environmentally friendly than coal or HFO, and the use of gas should be promoted from this perspective.

.3 Even though the risk associated with dependency on natural gas appears to be relatively low, it has not been sufficiently tested on any extended basis with respect to security of gas supply from other sources for use in the Nova Scotia market. Therefore, some caution is suggested, particularly for emergency facilities, for which back-up systems are recommended, at least until the level of security of gas supply has been proven.

5.4 Transmission and Transportation

5.4.1 Risk Definition

The risk associated with transmission and transportation refers to the ability to plan for, operate and maintain the delivery systems for HFO, LFO, propane, motive fuels; i.e. all energy sources, excepting electricity and gas, which have been previously discussed. It considers on time delivery to customers, but particularly to all critical facilities.

5.4.2 Analysis

A number of scenarios need to be considered:

.1 The previous section discussed a scenario where fuel retailers could not get fuels from the local refinery. This is a source problem, not a transportation problem, and will not be further discussed here.

.2 A second risk factor is inability to deliver fuel to customers due to infrastructure failure (roads, bridges, etc.) and/or roads and streets being closed due to trees and other debris caused by a major storm such as Hurricane Juan. Major storms such as this are sufficiently rare (1 in 100 years, or some such lengthy time period), to make the risk negligible. If infrastructure has failed for any other reason, it will be for a very short time period, as at least a temporary solution will be implemented quickly.

.3 The other risk factors revolve around gas, and these have been previously discussed.

5.4.3 Conclusions

.1 The risk for loss of local fuel supply is very low.

.2 The risk for loss of fuel delivery is also very low.

5.5 Environmental Factors

5.5.1 Risk Definition

Environmental risk factors include:

- air emissions (especially GHGs, SO_2, NOx, and particulates);
- noise (from gas turbines, wind turbines, etc.);
- aesthetics (related to new plants, wind turbines, etc.);
- discharges to surrounding environment (from industry, e.g. Tuft's Cove Generating Station, Imperial Oil, new IPP generating stations, from commercial and institution space heating plants, etc.);
- industrial and commercial oil spills;
- residential oil spills from leaking oil tanks;
- environmental impacts related to the construction of new power plants; and
- other factors.

5.5.2 Analysis

.1 The HRM CEP Task 1 Report provides a description of the current energy use by source within the municipality. This data is provided for the community as a whole. The corporate proportions of the estimates of energy consumption related to HRM's direct operations is broken out as a subset of the broader community energy use. The Task 1 report also provides the analysis of the specific GHG emissions for the current Business-as-Usual and future energy demand scenarios. In addition, Section 3.2 of the Task 1 report provides a comprehensive discussion of the true environmental and health effects associated with emissions and air pollutants produced by the consumption of carbon energy forms. Also, other HRM initiatives, including the Clean Air Strategy and GHG Emissions Inventory are active planning tools used by HRM to address these environmental concerns.

Therefore, this Section of the report does not address the environmental risks associated with emissions because they are discussed in more detail in the earlier report and other complementary strategies. It is acknowledged here that carbon based emissions producing greenhouse gases, and air quality problems resulting from carbon based energy, are amongst the greatest environmental concerns facing local and global societies today.

There are significant environmental risks associated with many of the other forms of energy used in HRM, including both renewable and non-renewable forms. In general, society has been aware of these concerns, and in most cases, standards and regulations have been put in place to mitigate the environmental, ecological, and health risks associated with the commodities.

.2 The generation of electricity with hydroelectric infrastructure that occurs within HRM has environmental risks. These include safety of the dams and potential effects to aquatic resources at the sites. There are very specific standards with respect to dam safety that require monitoring and maintenance, as well as both provincial and federal regulations around watercourse "use" licensing, and alterations. The regulatory process requires the periodic renewal for the use of watercourse systems where there is a fairly rigorous inter-governmental agency evaluation around the planned or continued use of the resource. The renewal of the license can include stipulations for the continued generation of power to address identified concerns. In general, these hydroelectric installations are closely regulated and do not pose unacceptable risks relative to their value to society.

.3 The transmission and distribution of electricity poses environmental risks which, for the most part, are well understood. Much of the concern relates to vegetation control required to keep the systems reliable during adverse weather conditions. In addition, transmission and distribution lines can traverse environmentally sensitive areas such as wetlands, watercourses, and critical habitat that can be disrupted during installation, maintenance or repair activities. Again, society has recognized these risks, and through both federal and provincial regulations, has established a broad range of regulations which would address the concerns identified by these risks. It is acknowledged also that NSPI is aware of these risks and is sensitive to its social responsibilities around these activities. They have demonstrated this by establishing internal environmental departments and conducting numerous studies and assessments to address specific concerns. These activities are closely regulated and do not pose unacceptable risks relative to their benefits.

.4 Prior to the realization that climate change is being largely caused by the combustion of carbon based fossil fuels in the production of energy, spills and leakage from petroleum hydrocarbon storage systems were recognized as one of the greatest environmental concerns in North America. Hundreds of millions of dollars have been spent in HRM investigating, remediating, and monitoring spills and releases from petroleum storage systems in this region. The locations of petroleum spills are also ubiquitous; present in both highly sensitive and lesser sensitive rural and urban areas. There is a correlation between throughput at a site (e.g. a bulk transfer facility), as well as the volume and age of systems, to the risk of a spills. In addition, owner knowledge, care and responsibility are very significant risk considerations.

While significant spills of petroleum products do occur regularly in HRM, very significant preventative measures have been adopted to control this risk. These measures have been regulated and are relatively effectively enforced. An additional incentive is the risk of civil liability, where third parties are injuriously impacted by the spill, or in some cases property values significantly devalued. For these reasons, major insurance agencies, working collaboratively with government agencies and oil suppliers, have helped reduce spills through the establishment of best practices, better technology, and improved monitoring of existing systems. While spills from petroleum storage systems still pose a risk to the environment, and will occur, it is expected that continued improvements will reduce the likelihood and severity of incidents in the future.

.5 The transportation of petroleum products, both in the marine environment (i.e. harbours within the region), and land transport by trucking, poses risks to the environment. These risks are well known. Currently, the risks are controlled in the regulation of these activities, as well by very established networks for spill response.

5.5.3 Conclusions

.1 There is no significant, unmitigated environmental risk that required action at this time.

5.6 Monetary

5.6.1 Risk Definition

Monetary risk has two components, cost and price. Cost is the capital cost to construct new infrastructure and the operating and maintenance (O&M) costs during subsequent operations. Price is what NSPI, Heritage Gas, MNP, IPPs, and fuel wholesalers and retailers, among others, charge their customers.

5.6.2 Analysis

.1 Cost risks related to electricity are initially borne by NSPI or IPPs. Applications, with varying degrees of success, will likely be made by NSPI to the UARB to pass some of these risks to their customers. The risks include capital cost overruns for the construction of new infrastructure, escalations in fuel costs and potentially other costs during operation, major equipment replacement due to failure (unplanned), and/or the addition of new major equipment due to environmental regulations. IPPs will typically have binding contracts with their customers, which may not contain sufficient escalation clauses. To be sufficiently profitable, IPPs must rigorously control costs, which means that trade-offs between profitability and operability/reliability may be entertained from time to time.

For NSPI, we understand that in the order of 50% of the total O&M costs relate to generation, 10% to transmission, 30% to distribution, and 10% for all other costs such as head office and central services, and a myriad of other miscellaneous costs. Given that a very high percentage of the generation costs is for fuel, escalations in fuel costs can have a very large impact on total operating costs.

The cost risks associated with other forms of energy are largely related to fuel cost escalations. Fuel retailers will transfer this to their customers, and so are hardly affected, as their customers must buy the fuel. However, this means that there is significant risk for the customer.

For wind energy generators, most of the costs are capital related and financial success is a function of the price paid for the energy produced and the Capacity Factor.

.2 As noted above, the price risk related to various fuels will be driven by the cost risk. As the costs to the retailers increase, the price to consumers, for the most part, will also increase, likely by the same percentage. The only dampening factor may be competition. However, any effect is minimal, as all participating retailers must maintain a certain level of profitability to stay in business, and so are unable to drastically cut their prices. HRM has among the lowest prices in the country for furnace fuel oil due largely to a large number of independent fuel retailers, a large customer base, and easy access to wholesale fuel from the Imperial Oil refinery. The Imperial Oil Canadian rack rate table consistently lists HRM as having the lowest wholesale fuel prices[1].

Currently, electricity prices in the province are regulated by the UARB. However, it is anticipated that, in the relatively near future, there will be at least a partial opening of the market to IPPs, and the price will become at least partially market driven. Currently, there is only speculation about the impact of a market driven price. In the deregulated markets of the United States, prices of electricity are very high compared to Nova Scotia. However, the experience of New Brunswick, upon deregulating its transmission level customer market (greater than 30% of the total load), was that very few customers were lost to IPPs, because they simply could not compete on a price basis with New Brunswick Power.

5.6.3 Conclusions

.1 The risk of fuel price escalation is very high, and HRM consumers can do nothing to influence this, nor can the fuel retailers. To the extent that retailers can, they will transfer their fuel cost increases to the consumers. A greater use of renewables might reduce this risk somewhat.

.2 As long as the price of electricity is regulated, the risk of price increase is somewhat controllable. HRM may be able to exert some influence by lobbying against price increases to the UARB.

.3 The impact of future partial or total deregulation of the electricity market is unknown, and will depend largely on the degree of penetration of IPPs in the market. Their shareholders will demand a minimum level of profitability which will, in turn, tend to pressure the price upward. However, this will be dampened by competition, both from NSP and other IPPs. It is likely that, over time, IPPs will gain a large share of the market and prices will increase significantly. HRM can do little

[1] www.limperiale.ca/Canada-English/files/products_industrial_wholesale/IW_rack_prices.pdf

to mitigate this risk. In the nearer term, say over the next twenty (20) to thirty (30) years, the risk to HRM will be low to medium, and for the most part, manageable and predictable, as long as HRM does not enter into some unfavourable long term contract with IPPs, which is unlikely.

5.7 Regulatory

5.7.1 Risk Definition

Currently, the Nova Scotia electricity market is fully regulated, with the exception of the Municipal Utilities (Munis), which can purchase electricity directly from IPPs, with only NSPI and the Munis permitted to sell electricity to retail consumers. It is noted that the Munis are also regulated by the UARB. The risk will evolve from the future partial, or full, deregulation of the market, which, in one sense, will be favourable to HRM as it will allow HRM to purchase "green" energy directly from renewable energy IPPs. However, this may also eventually cause the price of electricity to increase, as previously discussed.

5.7.2 Analysis

The following discussion is based largely on the experience in the United States.

There is no uniform electricity market in the USA but the structures in New England, New York, Pennsylvania, New Jersey and Maryland are similar. Other jurisdictions have chosen to maintain the fully regulated, vertically integrated utility, status quo.

One arguable benefit of competitive markets is that the discipline of the market is superior to the judgement of the regulator. For example, in New England, in theory, the risk of bad decisions by IPPs is carried by the IPP, whereas regulated generators, with regulatory approval, pass on prudently incurred costs to their customers who are presumed to benefit from utility decisions.

Also, in New England distribution utilities are required to sell off generation. Customers can choose to buy from marketers, or from the regulated distribution utility through what is called Standard Offer Service (SOS). SOS is basically a form of business as usual purchase from the regulated distribution utility. The distributor acquires SOS energy from a competitive bid process, and the offerings and prices are approved by the regulators.

In New England, the Independent System Operator (ISO) dispatches generation on the basis of competitive bids. All generators that are dispatched to supply energy in each hour are paid the same price as that of the highest bid priced accepted. Low cost producers can make considerable profits. High cost producers may not survive.

In New Brunswick, the original utility has been restructured into several entities: the System Operator that runs the system and the market, a conventional generator, a nuclear generator, and the transmission and distribution entities. The distribution entity is responsible for ensuring an adequate generation supply.

Nova Scotia has opted for a precautionary approach to market restructuring by limiting the energy retailers to buy from parties other than NSPI by approximately 1.5%.

5.7.3 Conclusions

.1 Nova Scotia has chosen to restructure its electricity market in a slow manner. It is argumentative whether this is good or bad for HRM. It reduces HRM's energy supply options for now, but in the short term, may provide more price stability.

.2 HRM should carefully evaluate how it might or might not benefit from a faster or slower restructuring of the NS electricity market. The best approach should be for HRM to be involved in all opportunities to protect its interests and make its position known.

6 SUMMARY OF ENERGY SUPPLY OBJECTIVES

The primary, overall energy supply goal is to ensure security of energy supply, while optimizing diversity, primarily by increasing the use of renewable and alternative energy. There are a number of energy supply objectives and actions related to this goal, which are outlined below.

.1 Utilize natural gas (strategically) in HRM. This could be a blend of gas fired distributed cogeneration (with or without district heat) and institutional boiler conversion, at several nodes in South End Halifax. The availability of gas in Halifax will increase the diversity of energy supply, which, in turn, should increase reliability and help to stabilize pricing.

Fewer larger (say 5 – 12 MW range) cogeneration plants have some advantages, such as capital cost/kW and less permitting issues, over many smaller plants in urban HRM. In addition to encouraging IPPs to develop such plants, consideration should also be given to NSP owning and operating some of the larger of these plants, particularly if the business case for an IPP proves to be challenging. The downside is that fewer plants result in fewer nodes, and therefore, less gas distribution piping, which could ultimately cause a delay in the implementation of the gas distribution system and the subsequent conversion of more buildings to gas.

.2 Fuels that were considered and are recommended to be eliminated from the perspective of new future energy supply objectives, are: nuclear, coal, petroleum coke, and heavy fuel oil (HFO). However, advanced coal gasification technologies and/or sequestration technologies could allow these energy sources to provide reliable, clean energy in the future that is competitive with natural gas. As new technologies emerge, these fuels should be reviewed again.

.3 The security of the current electricity supply system is high, as noted in Section 5. Existing generation at the Tuft's Cove Generating Station, the Burnside gas turbines and the St. Margaret's Bay hydro plants is reliable and relatively price stable, as are the other plants and transmission and distribution networks within the NSPI system. This should be maintained as is. However, the addition of gas fired cogeneration, green power purchases, and a renewable energy program to increase "domestically" produced generation is recommended to increase diversity and reliability relative to domestic sources.

This objective includes NSPI operating Tuft's Cove (TC) with natural gas as its primary fuel. This would significantly reduce GHG emissions in HRM. However, TC is the lowest emitter amongst NSPI's fossil fuel plants, so from a provincial utility perspective, the coal fired plants should be addressed first, or at least in tandem with TC. Any environmental benefits would be to the credit of NSPI and the province, unless HRM agreed to pay any premium arising from this course of action.

.4 Consider multiple "transformational projects", i.e. smaller DSM and energy supply projects, in addition to a small number of larger, "compelling" projects.

.5 Encourage the province to provide legislation and related regulations that opens up more of the electricity market to IPPs. These regulations could include the introduction of Standard Offer Contracts (SOCs) as the norm for Power Purchase Agreements (PPAs), and the carbon credits from renewable and alternative energy projects should remain the property of the owners of these projects. Unfortunately, this additional market access may be coupled with higher electrical rates to consumers from NSPI, particularly if there is an increase in wind energy projects. As previously noted, in this case NSPI will still be obligated to maintain the majority of its existing system capacity, as wind power is currently not accepted as a system capacity provider.

.6 Increase the use of renewable and other alternative energy sources. The means of doing this could include:

- buying "green energy" to the extent that regulations permit, assuming cost effectiveness is not compromised;
- solar DHW throughout HRM corporate facilities (with an educational campaign targeting private sector facilities and residences) to reduce fuel use and electrical energy load and supply requirement. This technology is seen as a very high priority, as it could have a significant impact if widely applied;
- green roof technology throughout HRM corporate facilities, where it makes sense to do so, again in tandem with a private sector awareness program, to reduce energy load and supply requirement, and to reduce stormwater runoff, and resultant pumping and treatment requirements;
- harbour cooling for downtown buildings on both sides of the harbour;
- innovative ways to utilize the waste heat from the Tuft's Cove Generating Station that is currently discharged to the harbour;
- process heat recovery from institutional and industrial facilities;
- wind projects in rural areas of HRM, where there is a demonstrated adequate wind regime to support such projects;
- biomass energy projects in rural areas; and
- AD biogas energy projects in rural areas.

.7 Utilize new domestic energy generation to support future load growth within HRM. The current NSPI generation plants must continue to operate, to maintain system capacity. While DSM and renewable/alternative energy supply programs will reduce the amount of new conventional future generation required, as the load grows over the years, the capacity of the existing plants and these new programs may be somewhat challenged.

New, relatively small distributed gas fired generation and cogeneration will provide some of the excess requirements, however, at some point, a new single larger plant will likely be required. This plant will likely be gas fired, and could be owned by NSPI, or one or more IPPs. One example of this could be a new, large gas turbine combined cycle plant at the site of the existing NSPI Water Street facility, perhaps combined with a district heating system. Alternatively, additional power and energy requirements could be purchased from sources external to the province, especially if the Maritime Provinces grid system becomes more integrated and the transmission tie to New Brunswick strengthened.

Alternative technologies to this could include a coal fuelled Integrated Gasification and Combined Cycle (IGCC) plant that could utilize indigenous Nova Scotia coal supplies but without the higher pollution typically associated with coal combustion. Other technologies that are currently prototypical may offer future alternatives. An example is renewable energy produced hydrogen that is stored and used in fuel cells to produce, on demand, electrical and thermal energy, with the only emission being water vapour. Alternatives to hydrogen production and storage using renewable energy could include pumped water storage reservoirs, or compressed air storage in underground salt caverns. Both alternatives are expensive and require unique geographic features, which may not be available within HRM, but they produce relatively low environmental impacts. These technologies could provide dispatchable energy on-demand to supplement non dispatchable renewable energy options such as wind or tidal power.

.8 Establish policies to permit the environmental enhancement of traditional municipal infrastructure, such as multi-use trenches for municipal services.

.9 Assess energy supply options in the development of all new sub-divisions and business/retail parks. There may be opportunities for gas fired cogeneration, renewable energy projects, and optimized distribution, as well as the obvious DSM opportunities. Also assess these options in land use planning, and in all future HRM planning activities.

.10 Increase the amount of energy generated throughout HRM using the NSPI net metering program (relatively small generation/cogeneration plants, located at the load(s) to provide electricity directly to the load(s), for which the annual energy generated is roughly the same as the energy consumed). Advise NSPI on ways to make net metering more appealing to HRM, such as increasing maximum generation from the current 100 kW limit, allowing multiple sites on a single system, etc.

With a higher kW limit and multiple sites, etc., a variety of energy sources could be considered. These include natural gas, biomass, biogas (from anaerobic digestion systems which “digest” organic material and produce biogas), small wind turbines, etc., either by themselves or in various combinations.

.11 Organize an aggressive campaign to encourage other Nova Scotia municipalities to go “green”, similar to HRM, so that HRM would possibly have more leverage in influencing the development of provincial government energy regulations.

.12 NSPI and the other Large Final Emitters (LFEs) in the province may be obligated by the Federal Government in the foreseeable future to reduce GHGs. Other emissions, specifically SOx, NOx and particulates, should also be reduced by these LFEs.

Obligate all facilities within HRM that use HFO as a primary fuel, such as the hospitals, universities, etc., to convert to natural gas, or dual fuel, with light fuel oil (LFO) as a back-up fuel. This will likely require government cost subsidies as an incentive to do this.

.13 HRM corporate and private sector demonstration programs, involving small generation/ cogeneration systems, are very important to the success of this CEP from a supply perspective. DSM demonstration programs are also very important. Financial incentives will likely be necessary for the initial implementation of these programs within the private sector.

.14 There is only one domestic source of heating and motive fuels, the Imperial Oil Limited (IOL) refinery in Eastern Passage. If this refinery shut down for any reason, these fuels would have to be imported from the Irving and other Canadian refineries, which would certainly cause a short term shortage and price increases. There is little that can be done by HRM to mitigate this risk, which is relatively low. However, it would seem prudent to open a dialogue with Irving Oil to determine their response time in such an event, and to assure that IOL provides HRM with the maximum notice about such an occurrence.

Appendix A

The Nova Scotia Electricity Market: Background Information

1. ELECTRICITY ACT OF NOVA SCOTIA – KEY POINTS

1.1 Renewable Energy Standard Schedule "A" Summary

.1 It grants Powers to the Minister and the UARB.

.2 The Minister may appoint an Administrator who decides:

- what is renewable energy and the rating; and
- how it performs and meets its commitments.

.3 The UARB can hear appeals on decisions of the Administrator.

.4 The Act requires that a Load Serving Entity (LSE, e.g. NSPI) must have, at least, the following minimum renewable energy in its portfolio:

- by 2010 - 5%; NSPI must buy this from IPPs;
- by 2013 – an additional 5%; NSPI can meet this requirement by purchasing renewable energy from IPPs, or from its own facilities, and energy purchased by the Municipal Utilities (Munis) from other than NSPI must meet these same requirements.

.5 A LSE is liable for a Penalty of up to $500,000 per day for failure to comply with the Act, after a one-year grace period. The LSE can compensate for a failure to supply renewable energy, provided that it delivers twice the amount, within the next twelve (12) month period, by which it failed to meet the requirements of the previous twelve month period.

1.2 Wholesale Market Rules Summary

.1 The Open Access Transmission Tariff (OATT) provides for independent generation sales to only wholesale (Munis) and export customers. Transmission services ($\geq$ 69 kV) offered are "point-to-point" and "network integration" services.

.2 Locational loss factors apply. There will be a penalty for generation facilities located east of Onslow, and a credit for locations west of Halifax. Note that a "generation facility" includes all equipment to the point of connection to the grid.

.3 For in province sales, ancillary services must be provided by NSPI. For export sales, the buyer or seller is responsible for obtaining the ancillary services.

2. SOME KEY POINTS FROM RECENT REPORTS PREPARED FOR THE NOVA SOCTIA DEPARTMENT OF ENERGY BY ROBERT CARY & ASSOCIATES

2.1 Key Points from Report on Policy Options

This report sets out the issues, generally without recommendations. Some of the notable issues discussed are:

.1 Renewable to Retail: NSPI to offer up to 25MW for transmission level customers.

.2 Unbundling of attributes or tags: Not recommended at this time.

.3 Regulated pricing issues: General agreement on energy at Marginal Cost (MC); capacity levelized based on future needs.

.4 NSPI requirements to satisfy the Renewable Energy Standard (RES): First trench NSPI cannot build, afterwards NSPI can build.

.5 UARB Role:

- oversight of system impact study and costs;
- regulate retail sales under Options B or C (defined in Section 2.2), especially with respect to small consumers;
- determine rates for top-up, spill, and null energy. "Top–up" is energy that a renewable generator is contracted to supply, but if it is unable to deliver, NSPI might be obligated to make up the difference. "Spill" means surplus energy over what the renewable generator is contracted to supply, and NSPI might be obligated to take and pay for that surplus. "Null Energy" is the actual kWhs produced without any environmental attributes attached; and
- oversee procurement of new capacity.

.6 Community Development: Standard Offer Contract (SOC) should not differentiate ownership with respect to any renewable generation (RG).

.7 Technology Development: SOC should not support novel technology development.

.8 NSPI System capability to absorb a certain amount of intermittent generation should be set in the interim by Nova Scotia System Operator (NSSO). An independent study will be required later on.

.9 Excluded Issues:

- scope of wholesale market;
- independence of system operator;
- maritime regional initiatives;
- DSM; and

- environmental targets for electricity sector.

2.2 Fundamental Policy Options from Report on Stakeholder Consultations

These options relate to the unbundling of attributes or tags, and include:

Option A: No unbundling, no sale of credits, no renewables without credits, no sale to external markets.

Option B: Permit developments beyond Renewable Energy Standard (RES). "Null electricity" sales (renewable energy from which the green attributes have been stripped for sale separately) would be regulated to prevent renewable attribute or offset sales to external jurisdictions.

Option B1: Renewable Generation (RG) that exceeds the 2013 (RES) requirements (Section 1.1.4) can be sold to 3rd parties.

Option B2: Similar to B1, but renewable energy sales to retail customers would offset RES requirements; i.e. the direct sale of renewable energy directly to retail customers.

Option C: Attributes can be unbundled from electricity sales. This would allow sales of RG > RES to retail customers not on transmission. Nova Scotia would be exposed to external market forces, but it is more conducive to a common Maritimes Market.

2.3 Some Key Points from Report on Stakeholder Consultations

.1 Nova Scotia is moving on global climate change (GCC) before the Federal Government. Until the recent greening of the Conservative Party, it appeared that the NS Progressive Conservatives were going to act on GCC before the Feds.

.2 All renewables are included, i.e. more than just wind energy.

.3 Renewable Energy Standard is same as Renewable Portfolio Standard (RPS).

.4 Options for Achieving Policy: NSPI builds all, vs. NSPI is excluded from emerging renewables. This is very contentious.

.5 NSPI uses a RFP process with UARB oversight.

.6 Standard Offer Contract (SOC) or Feed In Tariff (FIT); some success elsewhere.

.7 Recommendation: use RFP with smaller scale projects based on SOC and FIT.

.8 Top-up and Spill Services: “Energy” at Marginal cost; “Capacity” at levelized long term cost of new capacity. These rates would be approved by the UARB. NSPI has yet to file for same.

.9 Renewable to Retail sales: Financial Contracts or Actual Physical Sales? Phase 1, sales to large customers. Phase 2, if demand exists, sales to small customers via licensed service providers.

This means that new regulations might permit sale directly to retail customers by renewable generators. Options to achieve this might be financial contracts for quantities and prices agreed between the renewable generator and the customer, or physical contracts for the delivery of specific quantities and contractually defined rates. The latter is like the traditional supply, except that some or all of a buyer's energy is deemed to come from a renewable generator. The former may provide that some or all of the attributes are for the unique benefit of the customer, or may take the form of price hedges or whatever creative arrangements are made between willing buyers and sellers

.10 Unbundling of “Attributes” or “Tags” or Renewable Energy Credits (REC) from electricity generated.

- How do these terms relate to Emission Reduction Credits or Renewable Emissions Credits (REC)??
- How does all this relate to exports”?
- How can you get a REC and a Tag from the same kWh??

.11 EcoLogo and green-e say the Tag or Attribute is lost if any part is sold separately.

.12 Recommend against selling Tags from RES generation.

.13 System Impact Studies will be required to determine how much intermittent generation will be permitted and where. Also, what will be the value of intermittent generation.

.14 The Cary report argues that no NSPI assets will be stranded by a RES.

.15 IPPs are responsible for their own financial viability.

.16 Community based projects should compete on a level playing field with other IPP proponents.

.17 Projects built before 2002 should not be included as renewable for the purposes of the RES and REC.

.18 A 5MW limit is proposed for distribution system interconnection.

3. REFERENCE WEBSITES

3.1 NSPI Sites

.1 NSPI Open Access Transmission Tariff (OATT)
http://oasis.nspower.ca/documents/oatt/ApprovedOATT052005.pdf

.2 NSPI Generation Interconnection Procedures (GIP)
http://oasis.nspower.ca/documents/StandardGeneratorInterconnectionProcedures.pdf

.3 Appendix NSPI Generation Study Queue
http://oasis.nspower.ca/documents/QUEUE_Oct13_2006.pdf

.4 NSPI System Loss Factor
http://oasis.nspower.ca/documents/LossFactor.pdf

.5 NSPI Annual Report 2005
http://www.emera.com/investors/annual_report.shtml

.6 NSPI Tariffs
http://www.nspower.ca/documents/definitions/Tariffs_March2006.pdf

.7 NSPI Air Emissions Strategy
http://www.nspower.ca/about_nspi/rates_regs/regulatory_initiatives/air_emissions/index.shtml

.8 NSPI IRP Terms of Reference
http://www.nspower.ca/about_nspi/rates_regs/regulatory_initiatives/air_emissions/IntegratedResourcePlan.shtml

.9 NSPI Rate Request 2007
http://www.nspower.ca/documents/rate2007/DIRECT_EVIDENCE_REDACTED.pdf

3.2 Province of Nova Scotia Sites

.1 Energy Strategy Background Discussion Paper
http://www.gov.ns.ca/energy/AbsPage.aspx?id=1249&siteid=1&lang=1

.2 NS Energy Strategy Volumes I and II and Appendices
http://www.gov.ns.ca/energy/AbsPage.aspx?id=1247&siteid=1&lang=1

.3 EMGC Report
http://gsa2.gov.ns.ca/search?q=EMGC+Final+Report&btnG=Search&entqr=0&output=xml_nodtd&sort=date%3AD%3AL%3Ad1&btnG.y=1&client=GOVNS_BRANDED&btnG.x=1&ud=1&oe=UTF-8&ie=UTF-8&proxystylesheet=GOVNS_BRANDED&site=GOVNS_ENERGY

.4 NS The Green Energy Framework
http://www.gov.ns.ca/energy/files/drm/ec5ff7e1-d72c-4353-9ca7-638991e43f60.pdf

.5 NS Electricity Market Rules Development Committee (MRDC)
http://www.gov.ns.ca/energy/AbsPage.aspx?ID=1512&siteid=1&lang=1

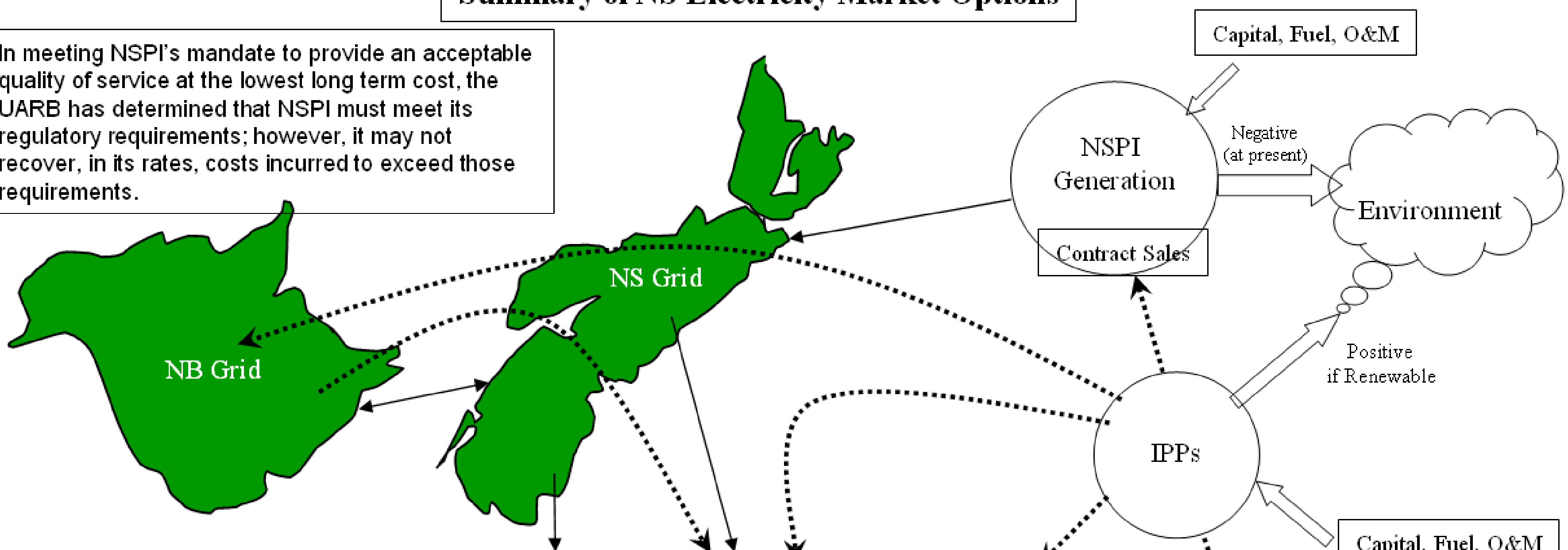
.6 MRDC - Complementary Discussion Documents
http://www.gov.ns.ca/energy/AbsPage.aspx?id=1565&lang=1&siteid=1

.7 Cary Report on Stakeholder Consultation
http://www.gov.ns.ca/energy/Download.aspx?serverfn=./files/drm/64afec42-72a9-475e-b427-ebe8b8f95617.pdf&downloadfn=Report

.8 Cary Report on Policy Options and Decisions
http://www.gov.ns.ca/energy/Download.aspx?serverfn=./files/drm/008b6f3d-4352-4ab8-9137-e58b4ee4c235.pdf&downloadfn=Report

Summary of NS Electricity Market Options

In meeting NSPI's mandate to provide an acceptable quality of service at the lowest long term cost, the UARB has determined that NSPI must meet its regulatory requirements; however, it may not recover, in its rates, costs incurred to exceed those requirements.



Concepts for Future Energy Purchase
- Null Energy - no attributes
- Top-up - NSP will cover shortfall
- Spill - NSP takes excess

Retail BAU:
Standard Offer by NSPI:
(fully regulated by UARB)
- Residential
- Commercial
- Industrial
- Other

Wholesale (Munis only for now):
- Bi-lateral Contracts with Back-up from from NSPI or 3rd Parties
- Retail (ie Residential, Commercial, Industrial, Other) not yet allowed

Direct
(Customer own use)

Unresolved Policy Options

A No unbundling, not "renewable" without attributes
B1 Renewable Generation (RG) > Renewable Energy Standard (RES) (2013) can be sold to 3rd parties
B2 As in B1 but renewable to retail offsets RES requirements
C Attributes can be unbundled from electricity sales

Definitions:
(1) Green Attributes, Renewable Attributes, Renewable Energy Credits, Transferable Renewable Credits, Green Tags said to be largely synonymous labels for the attributes of certifiable renewable resources. For NS, Tags will be called NSRECs
(2): Emission Reduction Credits and Offsets are largely synonymous BUT different from RECs, Tags etc.

Other Questions:
- Do Customers of IPP pay for inability of IPP to deliver reliability (**R**) or do IPP pay?
- Can NSPI satisfy its "renewable" requirements by purchasing from the grid or buying "credits" externally?
- What responsibilities do IPP have wrt **R**?
- Are IPPs subject to "penalties" for failure to deliver the attributes that LSE's require by NS law?

Legend
IPP ·····▶
NSPI ——▶