Nova Scotia POWER
An Emera Company

NSPI – APRIL 2012

Utility Performance Benchmarking Analysis

energy everywhere.™

Background

- Operating benchmarking is valuable in assessing the performance of the Company with its peer group to identify industry trends and opportunities.

- The absolute performance values are important but require analysis to fully correlate as differences in corporate structure (vertically integrated utility vs. distribution only utility) and accounting practices (capitalization policy, pension accounting) will influence absolute operating costs. The overall trending pattern of values provides greater insight on performance management with operating costs.

- As part of an operations review in 2007, the Nova Scotia Utility and Review Board (UARB) engaged the consulting firm Kaiser Associates (KA) to complete an internal analysis of NSPI and an external benchmarking study of relevant, comparable utilities focusing on OM&G costs.

Approach

- Overall approach of this operating performance benchmarking analysis was to apply the specific benchmarking metrics and comparable utilities used in the 2007 Kaiser Associates study. The three benchmarking metrics include:

  - Operating expense as a percent of revenue
  - Operating expense per customer
  - Operating expense per megawatt hour (MWh)

- The analysis was based solely on public information sources including annual financial reports, regulatory filings and company annual information forms

- The aggregate reported operating expenses were used. Operating results for comparable companies with other operations (eg. water utility, construction or real estate subsidiary) were segregated based on the available segment financial results contained in audited financial statements.

- Information is also presented on NSPI's capital employed per customer. Capital employed is an indicator of depreciation expense which is not a component of Operating.

Comparables

- Kaiser Associates screened a diverse mix of potential comparables and selected four principal comparables as well as two best in class comparables. NSPI's benchmarking analysis has retained these six utility comparables for its baseline review.

Newfoundland Power and NB Power were identified as "best in class" comparables. Both companies demonstrated characteristics in specific functional groups to lower overall OM&G expenses (eg. NB Power's vegetation management program and Newfoundland Power's customer service technology investments)

Comparables Profile

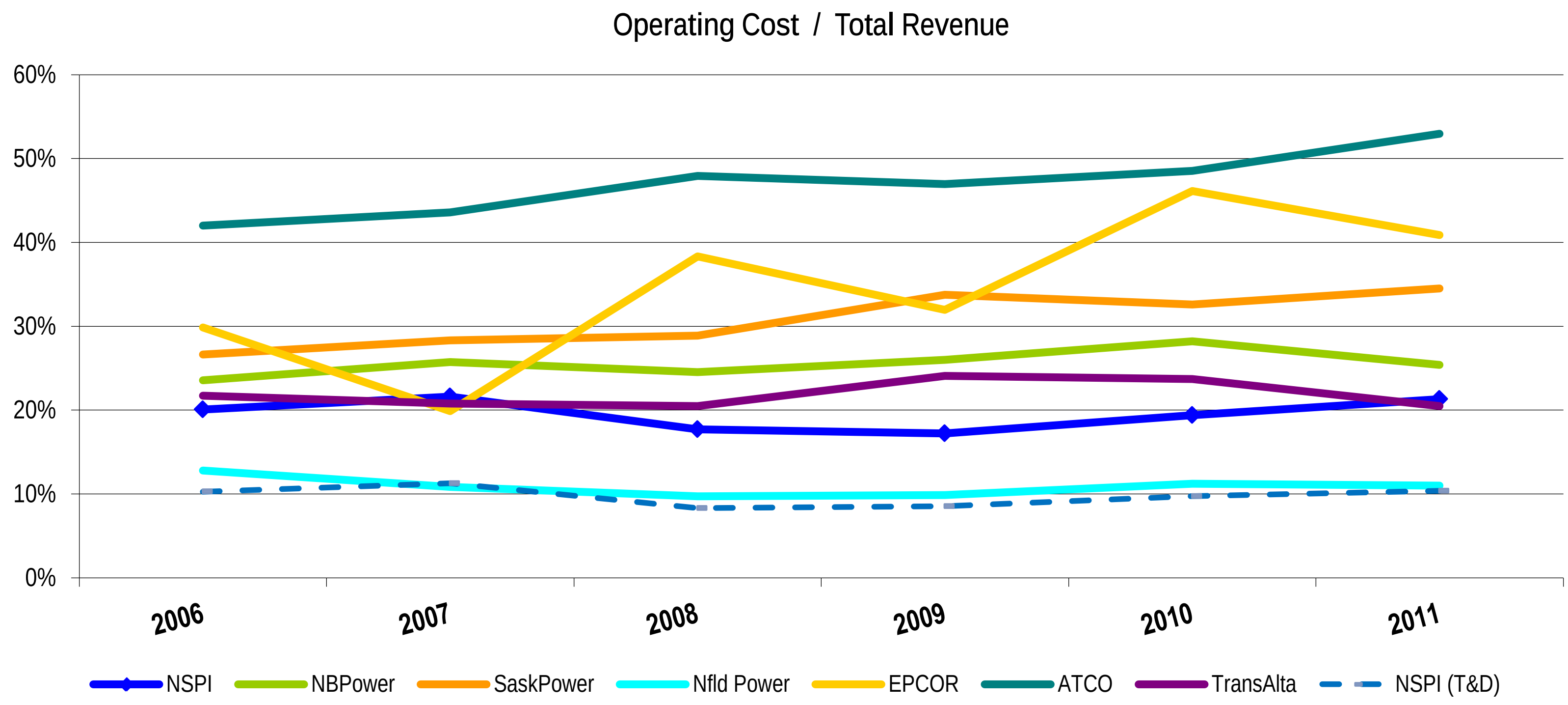
ATCO	Includes utilities and energy operating segments. ATCO utilities include a natural gas distribution and electric distribution & transmission operation as well as a natural gas transmission operation. The global enterprises and industrials business segments were excluded from the analysis. 1.4 million gas distribution and electric customers with 19 generation stations totaling 4,885 MW of capacity
EPCOR	Reflects electric distribution and transmission operations as well as a separate power generation business up to July 2009. The water and energy services business segments were excluded. 335,000 electric customers. Former generation portfolio included 3,500 MW of capacity at 31 facilities in Canada and US.
Énergie NB Power	NB Power is a vertically integrated electric utility. Cost of service regulation. Government owned and operated. 384,000 customers with generation capacity of 3,194 MW
NEWFOUNDLAND POWER A FORTIS COMPANY	Newfoundland Power is a cost of service regulated electric distribution and transmission company. OM&G costs exclude power generation function expenses. 243,000 customers with 85% residential mix
SaskPower	Vertically integrated electric utility. Cost of service regulation. Government owned and operated. 482,000 customers with 70% residential mix, 3,840 MW of generation capacity
TransAlta™	Merchant generation company with energy trading operations. OM&G costs exclude electric distribution and transmission function expenses. 8,641 MW of generation (54% coal, 25% renewable, 21% gas)

Comparables Profile

Company	Net Assets ($ Billion)	Number of Customers	Utility Type	Generation Capacity (MW)	Transmission Line (Kms)	Distribution Line (Kms)
ATCO	$12 Billion	1,411,000	Pipes, Wires, and Generation	4,885 MW	10,000 km	63,000 km
EPCOR	$1 Billion	338,100	Wires Only	n/a	203 km	5,548 km
NB Power	$5 Billion	383,896	Vertically Integrated	3,194 MW	6,841 km	20,595 km
Newfoundland Power	$1 Billion	243,426	Wires Only	140 MW	11,000 kms of both T&D	
NSPI	$3 Billion	491,158	Vertically Integrated	2,368 MW	5,000 km	29,000 km
SaskPower	$5 Billion	481,985	Vertically Integrated	3,840 MW	12,404 km	145,169 km
TransAlta	$9 Billion	n/a	Merchant Generation	8,641 MW	n/a	n/a

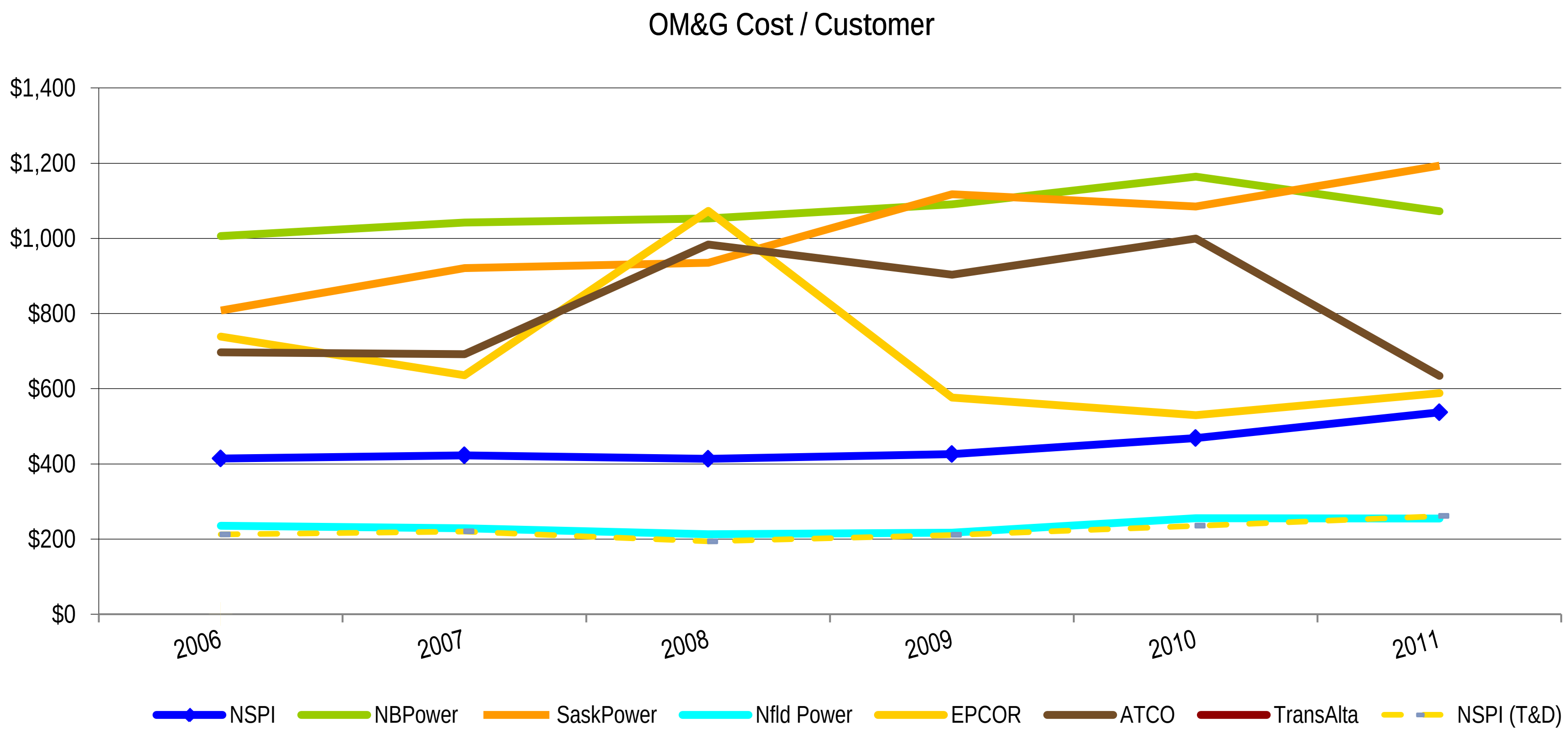
Operating expense vs. Revenue

NSPI has demonstrated a favourable trend in OM&G/Revenue in the period. NSPI's revenues have increased at a higher rate than increases in actual OM&G expenses based on the recovery of increased fuel costs. The NSPI (T&D) benchmark provides a position that is more comparable to wires only utilities such as Newfoundland Power.



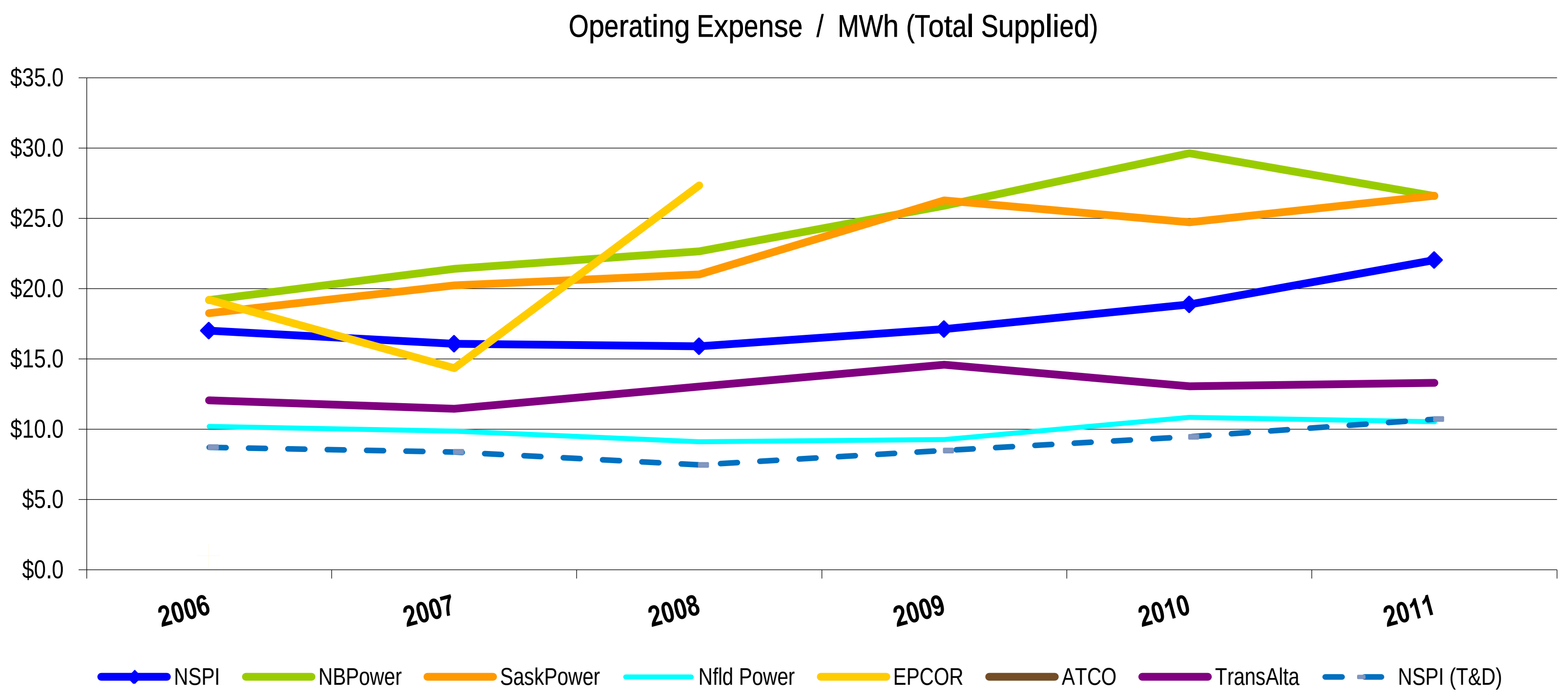
Operating Expense per Customer

NSPI has a lower OM&G expense per customer than its vertically integrated comparables and has demonstrated a constant trend profile over the period. Increased OM&G costs for 2010 are evident for NSPI and its peers.



Operating Expense per Mwh

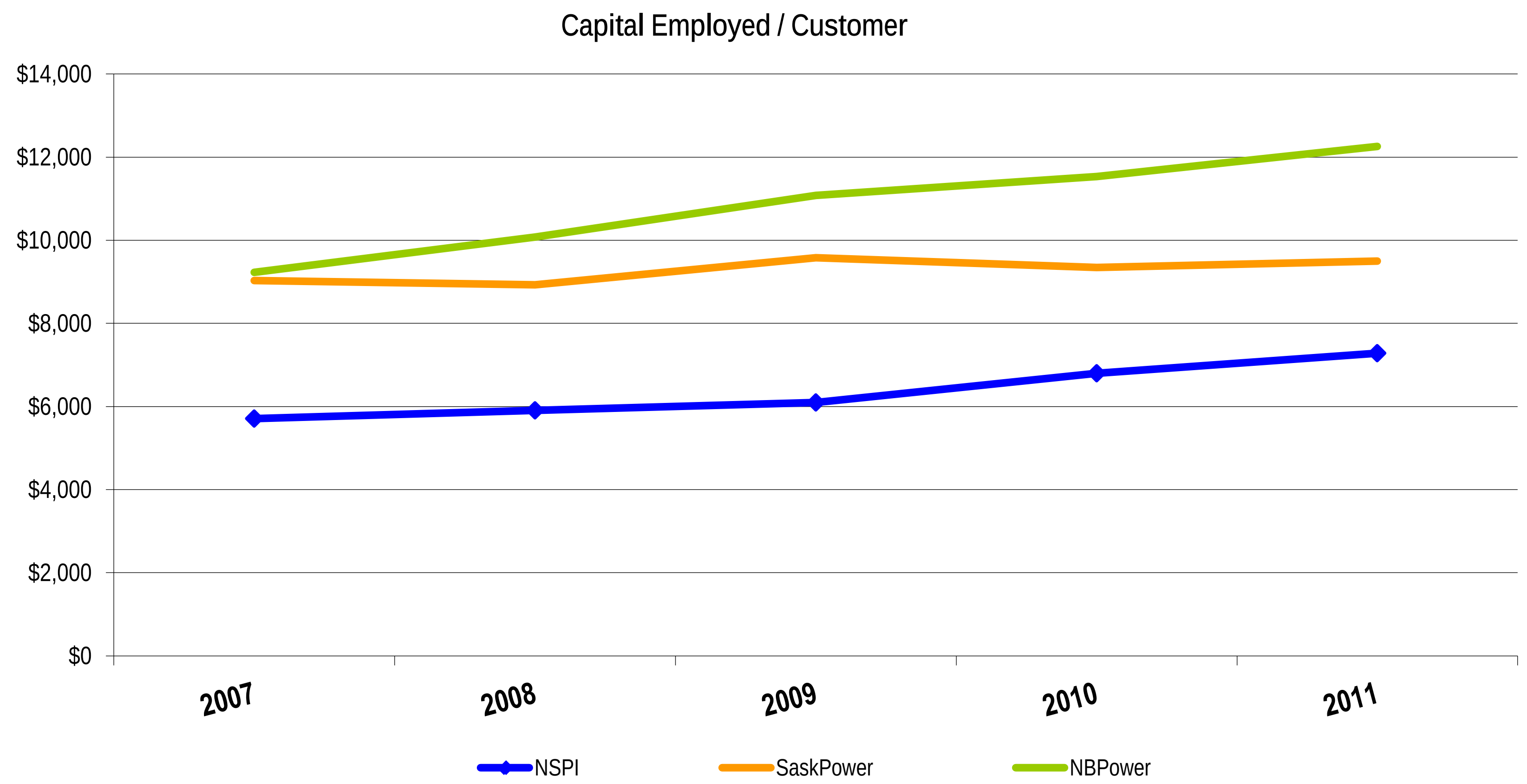
Relative to its vertically integrated utility peers, NSPI has the lowest Operating expense per mwh and has demonstrated a more favourable trend profile.



energy everywhere.™

Nova Scotia POWER An Emera Company

Capital Employed per Customer



1 FUEL PORTFOLIO, FUEL CONTRACTS AND TRANSPORTATION

NS Power's solid fuel procurement policy is to procure and manage a reliable and competitively priced supply of fuel on a system-wide evaluated cost basis for our generation fleet, consistent with regulatory and environmental requirements. Our policy incorporates a portfolio approach to procurement with contracts spanning various time frames and fuel characteristics. Figure 1-1 provides detailed information on the make-up of our Solid Fuel Portfolio.

Figure 1-1

[redacted]

Note: This figure is confidential.

NS Power reviews its commitments on an on-going basis, while monitoring our requirements and changes in market conditions to ensure the fuel portfolio is optimized to produce the lowest overall cost while meeting our environmental commitments. The fuel contracts that form the fuel portfolio are summarized in Figure 1.2 and outlined in the following sections.

Figure 1-2

[redacted]

Note: This figure is confidential.

1.1 Long-Term Contracts

NS Power enters into long-term commitments for a portion of solid fuel requirements. Long-term contracts are contracts that have a duration [redacted] or more.

NS Power has [redacted] commitments for solid fuel as follows:

Figure 1-3

[redacted]

Note: This figure is confidential.

[redacted].

1.2 Medium-Term Contracts

NS Power enters into medium-term commitments for solid fuel for a portion of its requirements. Medium-term contracts are defined as contracts that have a duration of [redacted].

NS Power has [redacted] contracts as follows:

Figure 1-4

[redacted]

Note: This figure is confidential.

1.3 Short-Term Contracts

The balance of NS Power's solid fuel requirements are purchased on a short-term basis. This amount varies based on overall burn and contractual volume options. The short-term commitments also include coal purchases for test burns and for emissions management.

1.4 Transportation

NS Power receives solid fuel at two port facilities. The International Pier, located in Sydney, receives self-unloading vessels that typically originate from along the eastern seaboard of North and South America. The second facility, the Point Tupper Marine Terminal (PTMT), has the ability to handle bulker vessels that can economically deliver coal from a greater number of supply basins.

We purchase most coal on a free-on-board (FOB) loadport basis and are therefore responsible for the procurement of ocean freight. Petroleum coke purchases are generally made on an as delivered basis with the supplier responsible for freight.

The type of freight we use depends primarily on economics but, as noted above, deliveries to the International Pier are currently limited to self-unloaders. PTMT can accommodate most vessel types.

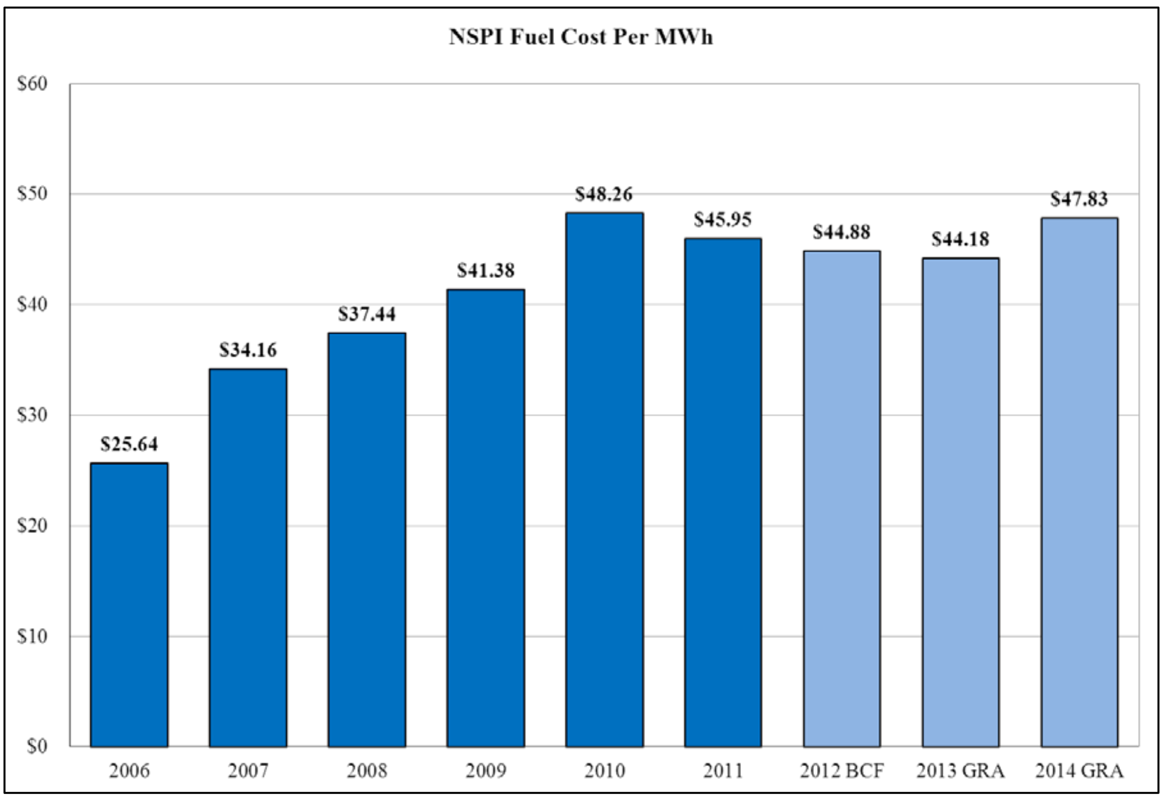
NS Power has multi-year ocean freight contracts in place with [redacted]. NS Power will be entering into new contracts in 2012 for freight for 2013 and beyond.

2 FUELS FORECAST

Fuel costs include the delivered cost of solid fuels, natural gas, oil, and purchased power, offset by the net proceeds from export energy sales.

As illustrated in Figure 1-5, the Base Cost of Fuel (BCF) decreases from $44.88/MWh, as determined in the 2012 GRA, to $44.18/MWh in 2013, with a subsequent increase to $47.83/MWh in 2014. This represents a 1.5 percent decrease in 2013, followed by an 8.2 percent increase in 2014.

Figure 1-1



The following sections provide details on our 2013 and 2014 fuel requirements, compared to 2012 BCF. All commodities that are purchased in United States Dollar (USD) have been converted to Canadian Dollars (CAD) at an average exchange rate of $1.0136 CAD for each USD in 2013 and $1.0138 CAD for each USD in 2014. The derivation of this exchange rate is described later in this section of this document.

2.1 Solid Fuels Forecast

In developing the solid fuel budget for this Application, NS Power followed the forecasting methodology outlined in the FAM POA.

Solid fuel is used at four generating facilities.[1] Most of the coal and all of the petroleum coke consumed at these stations is imported. NS Power purchases domestic coal when it is available, meets environmental requirements, and is competitively priced. The blended average solid fuel costs are shown in Figure 1-6.

Figure 1-7 compares the mix of solid fuels in the 2012 BCF to the forecast mix in the 2013 and 2014.

Figure 1-2

[redacted]

Note: This figure is confidential.

This reflects a combination of a change in the fuel mix, lower petcoke pricing, and a softening in the global coal price.

[1] Lingan, Point Aconi, Point Tupper and Trenton.

Figure 1-3

[redacted]

Note: This figure is confidential.

2.2 Natural Gas Forecast

Figure 1-8 shows the cost of natural gas in the 2013 and 2014 GRA forecasts versus the 2012 BCF. We forecast the average cost of natural gas consumed, including transportation charges to Tufts Cove, to be [redacted] delivered in 2013, and [redacted] delivered in 2014. The lower price in 2013 is driven by falling natural gas prices. The 2014 price reflects our forecast for [redacted].

Figure 1-4

[redacted]

Note: This figure is confidential.

We manage financial exposure to changes in the market price of HFO and natural gas through the use of swaps.[2]

The HFO and natural gas prices in this Application are produced using forward price curves and in-place hedges.[3]

2.3 Biomass

The table below illustrates the current forecast pricing relative to what was in the original capital filing for the Port Hawkesbury Biomass facility.[4]

Figure 1-5

[redacted]

Note: This figure is confidential.

The fuel cost increase in this Application relative to the original capital filing has increased on the basis that the lower cost residual biomass fuel from the mill is not available.

---

[2] Swap contracts are financial instruments used to lower volatility in pricing terms for a supply contract.

[3] The term *forward price curve* refers to a graph of future prices decided upon by both buyer and seller for any given commodity.

[4] NSPI Port Hawkesbury Biomass Capital Work Order Application, NSUARB-NSPI-P-128.10, April 9, 2010, Appendix 8.

2.4 Heavy Fuel Oil (HFO)

Given the relative forward market prices of each fuel, Tufts Cove is not expected to burn HFO in the dual-fired steam boilers (Units 1-3).

We anticipate consuming 20,000 barrels of HFO in 2013, and 23,000 barrels of HFO in 2014 as support fuel at our coal fired plants, compared to 646,000 barrels in the 2012 BCF.

Figure 1-10 shows HFO costs for 2013 and 2014 versus the 2012 BCF. The forecast price is [redacted] in 2013 and [redacted] in 2014, or approximately [redacted] in 2013, and [redacted] in 2014 per barrel delivered. The 2014 price represents an increase of 13 percent in the unit price of HFO relative to the 2012 BCF.

Figure 1-6

[redacted]

Note: This figure is confidential.

2.5 Light Fuel Oil (LFO)

We expect to consume 11.3 million gallons of LFO in 2013 and 2014 as start-up fuel in our thermal units and for operation of the oil-fired combustion turbines. The quantity of

LFO forecast is lower than the 2012 BCF consumption of 22 million gallons, reflecting projected lower peak demand requirements. Figure 1-11 shows LFO price for the 2013 and 2014 GRA versus the 2012 BCF. The forecast price for LFO in 2013 is [redacted], and the forecast price for LFO in 2014 is [redacted]. This is a [redacted] increase per MMBtu relative to the 2012 BCF.

Figure 1-7

[redacted]

Note: This figure is confidential.

2.6 Renewable Energy

2.6.1 NS Power-Owned

The renewable energy generated by NS Power comes from hydro, tidal, wind and biomass.

The level of hydro generation forecast for 2012 is based on a 23-year average, consistent with the Board's 2002 Rate Decision, in which the Board stated "longer-term data is preferable for purposes of hydro generation".[5] The use of this average, results in a 2013 and 2014 production forecast of 985 GWh per year.

---

[5] NSPI 2002 Rate Case, UARB Decision, NSUARB-NSPI-P-875, October 23, 2002, paragraph 91.

We forecast the Nuttby Mountain Wind Farm will produce 140 GWh, the Digby Wind Farm to produce 110 GWh and wind turbines located at Grand Étang and Little Brook to produce a total of 3.3 GWh in 2013 and 2014 (per year). We also have a 46.69 percent stake in the Point Tupper Wind Farm, which we forecast to produce 68 GWh in 2013 and 2014 (per year).

2.6.2 Independent Power Producer Contracts

Prior to the end of 2001, we entered into four long-term Power Purchase Agreements (PPAs) with independent power producers to produce renewable energy from biomass and hydro. The total capacity from these pre-2001 contracts totals approximately 24 MW and we forecast them to produce 156 GWh annually for 2013 and 2014.

Between 2002 and 2008, we procured the output from an additional 62 MW of renewable energy, primarily from wind sources, through long-term PPAs. As part of the 62 MW, Pubnico Point Wind Farm Inc. began full production from its 30.6 MW wind farm at Pubnico Point in early 2005 and continues to produce approximately [redacted] annually. During the period from 2002 to 2008, NS Power executed PPAs with five wind developers, one biomass developer and one biogas developer.[6] Total generation from these post-2001 contracts is approximately 160 GWh annually.

Since 2008, we have entered into PPAs for an additional 218 MW of wind energy capacity. Of the 218 MW, 193 MW will come from five transmission connected projects. The remaining 25 MW will come from smaller distribution connected projects.

In 2009, the 51 MW wind farm at Dalhousie Mountain was operational. In 2010, the following wind farms came on line: Nuttby Mountain (50 MW), Digby (30 MW),

[6] Comeau Lumber Limited, a biomass developer, filed for bankruptcy protection in early 2009. The PPA will remain in effect if they are able to resume production.

Maryvale (6 MW), and Point Tupper (22 MW). By the end of 2011, the 62 MW facility at Glen Dhu was fully operational. The remaining smaller projects began coming online in 2011, and NS Power expects all to be operational by mid-2013. Generation from these post-2008 contracts totals approximately 470 GWh annually.

The additional procurement of 218 MW since 2008 was largely driven by the provincial renewable electricity requirements. In 2004, the Nova Scotia government passed legislation outlining renewable energy requirements going forward.[7] The Renewable Electricity Regulations created a Renewable Electricity Standard (RES) that required, by 2011, NS Power produce five percent of its energy from renewable resources constructed after 2001.

By 2013, this target is increased to 10 percent, or approximately 1,075 GWh for the 2013 GRA forecasts. NS Power forecasts qualifying projects to contribute 1,315 GWh of energy in 2013, and 1,532 GWh of energy in 2014. More detailed capacity and generation information is available in standardized filing section OP-06.

Please refer to Appendix C for NS Power's RES Compliance Plan.

2.7 Load Forecast

As described in previous sections, the decrease in fuel expenses for 2013 is partially a function of changes in commodity prices and purchased power.

The 2013 total system requirement is forecast to be 10,751 GWh in 2013 and 10,740 in 2014, including exports, versus 12,682 GWh in the 2012 BCF. The majority of this load decrease is related to in-province load.

---

[7] Renewable Electricity Regulations, made under Section 5 of the *Electricity Act*, S.N.S. 2004, c.25.

We expect to export a small amount of energy in 2013 and 2014. These 2013 and 2014 export sales reduce the overall revenue requirement by $0.3 million, to the benefit of customers. The load forecast is discussed in greater detail in Section 3.

2.8 US Dollar Requirements and Foreign Exchange Rates

Most of our fuel requirement is purchased in United States Dollars (USD), as global fuel markets are USD denominated.

We typically use forward contracts to hedge our USD requirements for fuel. A forward contract is a commitment to purchase specific securities (in this case, USD) at an agreed upon rate at a specific date in the future.

We hedge our USD requirements based on known and forecast requirements. Our guidelines are to hedge 30 to 50 percent of the three forward years. For the current 12-month period, a maximum of 30 percent of the forecast USD requirement would remain open to allow for changes in the cash flow timing and volume of USD requirements. The hedged rates are factored into the costs for fuel.

We monitor and report on our risk management strategies. This includes budgeted volumes of underlying positions not hedged and risk management strategies regarding revisions to the budget volume.

Through our purchase of forward foreign exchange contracts, we have 67 percent of our 2013 and 2014 USD requirements at an average rate of 1.0251 (2013) and 1.0106 (2014) and have forecast a blended rate of 1.0136 (2013) and 1.0138 (2014) on all fuel costs in this Application. The blended rate in the 2012 BCF is 1.0089.

RES 2013, 2015 and 2020 Compliance

	Assumes Bowater on , PH Mill off		
	RES 2013	**RES 2015**	**RES 2020**
NSR	10,721	11,274	11,922
DSM effects	(DSM inlcuded)	528	1,263
NSR less DSM	10,721	10,746	10,659
Sales (Assume 7% Losses)	10,020	10,043	9,961
RES %	10%	25%	40%
RES Requirement (GWh)	**1002**	**2511**	**3985**
NSPI Wind	254	254	254
Post 2001 IPPS	742	742	742
PH Biomass Project	323	418	418
COMFIT	0	100	300
Small Hydro - Marshall Falls	0	0	15
Minas Basin Biomass	0	55	55
Pre 2001 IPPS	156	156	156
NSPI Legacy Hydro	985	985	985
Maritime Link	0	0	1102
Total Renewable Energy	**1318**	**2709**	**4026**
Surplus/Deficit	316	198	41

Assumes Bowater on; PH Mill PM2 on (PM2 ~1140 GWh)		
RES 2013	**RES 2015**	**RES 2020**
11,861	12,414	13,062
(DSM inlcuded)	528	1,263
11,861	11,886	11,799
11,085	11,108	11,027
10%	25%	40%
1109	**2777**	**4411**
254	254	254
742	742	742
269	357	357
0	100	300
0	0	15
0	55	55
156	156	156
985	985	985
0	0	1102
1264	**2648**	**3965**
156	**-129**	**-446**

Options for 2015 and Beyond Renewable Energy Supply

Wind	150	
Maritime Link -Supplemental Purchase		500

Notes:
Jan 2012 GRA Load Forecast
NSPI Wind and IPP Wind as per 2014 GRA assumptions
PH Biomass project output is dependent on whether the PH Paper Mill is on or off.

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

Testimony of Leonard Crook, ICF International

(04-30-2012)

Q. Please state the purpose of your testimony.

The purpose of this testimony is to provide ICF's market outlook and view of developments in the natural gas market and to comment on NSPI's gas acquisition strategy in the context of our views.

Q. What is your role with NSPI?

By way of background, since 2006, my colleagues at ICF and I have provided NSPI with assistance on various aspects of natural gas supply and planning, including:

- Evaluating future natural gas needs
- Assessing the benefits and costs of natural gas storage
- Reviewing and commenting on internal NSPI studies about gas market developments in the Maritimes
- Advising on the RFPs for both replacement natural gas supplies and for resales of excess gas supply
- Evaluating bids submitted under various RFPs
- Advising in supply contract negotiations
- Hedging analysis

ICF's most recent work for NSPI has been to assess basis hedging options. In short, ICF has advised on NSPI's natural gas decision making as an independent third party reviewer and advisor.

I have filed testimony from time to time with the Board on some of these issues on behalf of NSPI.

Q. Please comment on the state of the natural gas market in which NSPI operates.

Natural gas prices in North America are set by what we call gas-on-gas competition where gas prices are determined by the forces of supply and demand across a large, highly interconnected (via pipelines) gas market. In contrast with the North American market, gas prices in other markets are generally set in reference to other fuels, most often oil.

Gas-on-gas competition manifests itself with trading (buying and selling gas) at market centres or trading “hubs” where buyers and sellers conduct transactions. There are a number of types of transactions in or around these hubs. At the core are arms-length transactions for fixed volumes of gas. Most often, these transactions are for a single day of gas supply, with the trade occurring on the day before the gas is delivered. There are also monthly transactions where a daily volume of gas is bought or sold for delivery on every day in the following month.

Gas prices are reported in the trade publications at around 100 market hubs. The trading companies report the volumes and prices of the trades to the trade publications. To assist in price transparency and to ensure accurate reporting, the industry has developed best practices for the reporting of these prices and regulators, such as the U.S. Federal Energy Regulatory Commission (FERC), have adopted standards for the reporting of these prices as they apply to the jurisdictional tariffs and rates of pipelines.

Hubs are often located near concentrations of supply (or storage), interconnections between pipelines, and in proximity to large end-use markets. In short, the location of hubs is determined by natural congregation of trading participants. As new points of interest develop, the trade publications add locations where prices are collected and reported. Occasionally, price reporting at a location may be discontinued when activity at the location drops to a level where there is insufficient volume to assure meaningful price data.

Prices at these hubs reflect local and regional supply/demand balances which are in turn influenced by pipeline capacity to and from these locations. Prices at one hub can be related to prices at a connected hub and so on across the continent by differences in transportation costs and supply sources. The price difference between any two hubs is called the "basis." The basis is a measure of the *value* of gas pipeline transportation between two locations along the pipeline network. These values are affected by the regulated transportation rates for pipeline services, but can produce values that are either higher or lower than the regulated cost of transporting the gas. I should also clarify that the prices quoted at market hubs are for the commodity only, and do not include explicit transportation costs or other elements of value to a user. Thus the basis spread between any two connected market hubs implies a value for pipeline transportation under the current market conditions at those market hubs.

Henry Hub in Louisiana is a national marker for natural gas prices due to its designation by the New York Mercantile Exchange (NYMEX) as the delivery point for gas futures contracts. Much of the time, prices at other hubs move in concert with Henry Hub prices. (Gas prices have a seasonal pricing pattern because so much of the gas is used for heating; this also causes prices in many locations to move in similar patterns.) When they do not move in concert it is because of local or regional developments, usually supply availability or weather that causes the basis between Henry Hub and the other hub location to diverge from normal spreads.

As I said, pricing at any one hub reflects the market balance in that region. Strong demand in a region, due for example to a cold front affecting that region, can cause gas prices to spike relative to other hubs which may not be influenced by the cold front. Pipeline capacity into a region affects the ability of supply to reach the market and has an influence on prices when pipes are constrained, due either to an outage or very strong demand relative to pipeline capacity. When this happens in consuming markets, prices in those markets spike and the basis to Henry Hub or some other relevant hub becomes very high. When it happens in a way to bottle up supply in a region, i.e., where there is more gas trying to reach market than there is pipeline capacity to carry the gas out of the producing region, the prices in the region can collapse and again, the basis between that region and Henry Hub or other market hubs will expand. Basis spreads, like gas prices themselves, can be volatile. The NYMEX offers basis swap products at a number of other hub locations where the product is the basis from Henry Hub. (There is no basis swap offered for Dracut, however.)

What I have described above takes place in both the daily spot market and the month-ahead market. All gas is traded in bi-lateral contract deals between producers, marketers, distributors, and end users. Most gas moves under month-ahead contracts, where the buyer and seller agree on a price indexed to a first of the month price quoted for those hubs with first of the month pricing (not all hubs have such pricing, Dracut does not). For those contracts, the buyer pays the seller the first of the month price for the duration of the month for a set volume of gas. When more or less gas is needed, buyers and sellers can enter the daily spot market to round out their sales and purchases. There is no price or volume reporting for "indexed" gas transactions.[1]

Hub pricing, basis relationships, and the dynamics around hub pricing are signature characteristics of the North American market. Because of these characteristics, there is enormous price transparency in the markets and overall significant market liquidity, such that at some price gas will always be able to be bought or sold.

One of the hubs with price reporting nearest and most relevant to NSPI is at Dracut, Massachusetts, where M&NP-US meets the Tennessee Gas Pipeline (TGP), near Boston. NSPI's current gas contracts are priced in reference to daily prices at Dracut. Other relevant hubs are TGP-Zone 6 and Algonquin Gas Transmission (AGT) City Gates. (Some hubs are not specific points but are pipeline zones or an accumulation of points on

[1] In addition to fixed price and "indexed" gas transactions, there are also transactions that are customized to the specific needs of a buyer or seller. One such transaction is a "swing volume" transaction, where a minimum and maximum daily volume is specified and one of the parties, generally the buyer, has the right to take an amount gas each day that is between the maximum and the minimum quantity. Often swing volumes are combined with a fixed or "base" volume in a single contract. Since the buy is receiving an "option" to vary a volume of gas, there is generally a premium above the price paid for fix volumes of gas associated with swing service.

a pipeline.) As such, there is trading on the TGP pipeline in its northernmost market zone adjacent to Dracut – this is Tennessee Zone 6. (Trading takes place on other segments of TGP as well.) Similarly gas prices are quoted on the other major pipeline serving New England, Algonquin Gas Transmission (AGT), as the Algonquin City Gates.

Historically, natural gas destined for New England came from several areas – the U.S. Gulf Coast over the Texas Eastern Transmission Company (TETCO), which feeds AGT at Lambertville, New Jersey, at another trading hub referred to as Tetco-M3 (so designated for the third market zone on the pipeline). TGP also has brought gas into New England from the Gulf Coast, but also from Midwestern Sources, and since the 1990s, from Western Canada via TransCanada Pipeline (TCPL) interconnections at Niagara, N.Y. The Portland Natural Gas Transmission System (PNGTS) entered service in the early 2000s bringing Canadian gas from Alberta into New England via Ontario and Quebec and feeding into the M&NP-US pipeline. Since the 1970s New England has received liquefied natural gas (LNG) from the Distrigas LNG import terminal in Everett, Massachusetts (Boston Harbor). With the inauguration of Sable Energy Offshore Project (SOEP) production in 2000 and construction of the MNP system in both Canada and the U.S., Nova Scotian gas has also been available to New England, and for the first time in Nova Scotia itself. Since 2009, the Canaport LNG terminal has provided gas for New England.

For much of its history as a gas consuming market, the gas supply in New England has come from relatively distant places – the Gulf Coast, the Mid-America region, and Alberta. In a sense, New England was at the “end of the pipe.” The transportation costs over the long distance pipelines tended to make New England a high-priced market relative to areas closer to supply. This is one reason for the viability of the Distrigas terminal in Everett. Similarly, economics supporting the development of Nova Scotian gas was possible by the high prices prevailing in New England.

Q. You said NSPI gas prices are set in reference to Dracut prices. Would you explain that statement?

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

The vast majority of all modern gas contracts in North America that are longer than a single day are priced relative to some gas market index, be it Henry Hub or some other hub. In the past, before the gas market evolved to what it is today, gas prices might have been fixed with an escalator (for example, the quarterly change in the GDP), or tied to some other market-priced fuel like oil. NSPI's former long-term gas supply contract had elements of each in it. Today, with a much more robust market dominated by gas-on-gas competition, contracts typically refer to an appropriate index for the base price of the gas. The index chosen depends on the location of the transaction, where a California transaction would be based on one of the California border points, an Ontario transaction might be based at Dawn, Ontario and so on.

To this publicly available index price, amounts will be added or subtracted depending on the physical location of the delivery point relative to the index (i.e., is the gas to be delivered to the buyer upstream or downstream of the index point) and to reflect other terms in the contract that affect value. These include, for example, the commitment to firm deliveries or interruptible deliveries; take-or-pay requirements; resale limitations; variability in takes; renewal terms, and so forth. In point of fact, the gas price in a contract will be different from the pure commodity value of the gas that one might see in a published hub index price for the spot market because of the terms of the contracts themselves. Gas is seldom sold as a pure commodity but is sold as a delivered service. This is clearly the case with NSPI in its term contracts where there are provisions that enhance the value of the delivered gas and thus affect the price relative to pure commodity sales.

To elaborate on this point, NSPI's gas purchasing strategy has focused on flexibility to ensure that it has enough but no more gas than is required to meet the burn at Tufts Cove. This has been done by layering contracts with different suppliers and by relying on daily markets to fill in the gaps. Within the contracts themselves, there are different tranches of supply at different prices and delivery requirements that further allow NSPI to tailor the supply to the expected burn. Furthermore, the flexibility also allows NSPI to respond quickly to price changes – using more gas when the price is low, for example.

Q. Would you comment on current developments in North American gas markets that may affect NSPI's gas purchases and purchase costs?

The most important development in natural gas markets is the collapse of gas prices relative to the recent past. This collapse has been driven by the following major events: 1) the recession of 2007, which reduced natural gas demand primarily in the industrial, commercial and power generation sectors; 2) extremely warm weather in North America in 2011-2012 that reduced gas demand for space heating, and; 3) the improvements in drilling technology that have allowed for the exploration and production of unconventional gas supplies, most notably shale gas.

The North American natural gas market has been characterized by significant price volatility. The last several years have been particularly remarkable in that regard, with the effects of the Gulf hurricanes in the fall of 2005 and the run up in oil prices in July 2008 (Brent crude was $144/bbl) that also pulled natural gas prices significantly higher (Henry Hub hit $13.00/MMBtu). From that high point, both oil and gas prices declined, but where oil has since rebounded, North American gas prices have declined and appear to have de-coupled from oil. Today, gas prices at Henry Hub are hovering around $2.00 per MMBtu while Gulf Coast residual fuel oil prices are near $18.00 per MMBtu (with crude trading at $105 per barrel).[2] The low gas prices are due to several factors as noted above: increased supply, a still weak economy, and a warmer than normal winter. Meanwhile, oil prices are set in an international market where demand has been strong and anxiety about Middleastern conflict has increased prices.

The major longer term trend however is the growth of shale gas resources and the resulting increase in gas supply in North America. ICF provides a quarterly gas market forecast to clients under our Compass service. Our current view, which we are advising clients, is that the growth in shale gas is the dominant development in the North American market and it is having significant effects across the continent. The shale gas

[2] Platts *Gas Daily*, March 28, 2012. See also The Wall Street Journal, "Once Linked, Oil and Gas Break Up." March 30, 2012.

production will help to moderate prices nationally and change the patterns of natural gas flows, particularly in the east. We nevertheless believe that the current prices are unsustainably low and that prices will rebound once producers begin slowing their drilling rates and shut in wells. Over the longer run, ICF expects gas prices to firm with economic recovery, a return to normal weather, and the decline in the supply surplus as producers have scaled back their production plans in the face of low prices. Still, we expect prices over the next five years to be in the $4.00/MMBtu to $5.50/MMBtu. This is higher than some forecasts, but represents our assessment of the effects of less well drilling and higher demand due to prices and economic recovery. It also assumes more normal weather.

Q. How does imported LNG fit into the North American market?

LNG historically has been attracted to North America when gas prices have been high or supply weak. The first wave of LNG import terminals were built in the late 1970s (Distrigas) and early 1980s (Cove Point, Elba Island, and Lake Charles). This was a period of perceived gas shortages due to price regulation of interstate gas supplies and the terminals were part of pipeline efforts to get more supply. Reform of gas markets and exporters' insistence on receiving higher prices than the U.S. buyers would accept led to the shutdown of these terminals, except for Distrigas and to some extent Lake Charles throughout the balance of the 1980s and 1990s.[3]

Beginning in the early 2000s, with the run-up in natural gas prices in North America due to declining production of conventional gas, many more LNG import terminals were planned and constructed and the old terminals taken out of mothballs. Canaport is part of this second wave of construction. Initially, utilization rates at the new terminals were low due to a lack of supply of LNG. Most LNG was transacted using long-term contracts with other buyers and new export capacity was not yet on line. With the advent of new supplies, such as those from Trinidad and Tobago, more supply began coming to the

[3] These facilities operated at very low load factors. Distrigas, as an important component of New England and Boston gas supply, continued to buy Algerian gas from time to time, mainly to supplement winter supply. The Trunkline facility at Lake Charles actually suspended service for a while but restarted around 1988-89 to take occasional cargoes.

United States, but still far below the import potential. Gas prices in Europe and the Far East were higher and sales more attractive in those markets. Then, unfortunately for the new LNG import terminals, shale gas made its appearance into the market. North America is now perceived to have an overabundance of supply. Gas prices have declined to the point that most of the import terminals in the U.S. are seeking permission to install liquefaction facilities to make LNG and export authorizations from the Department of Energy.

Q. Would you please contrast world LNG markets with the North American market?

Most LNG is traded under long-term contracts that tie the seller to the buyer over a defined trade arrangement where liquefaction, tankers, and regasification facilities are dedicated to the transaction. LNG trades can be characterized in two geographic markets: the Atlantic Basin and the Pacific Basin. The main consuming market in the Atlantic is Europe; in the Pacific, Japan and Korea, with growing demand in China and India. Natural gas prices in Europe are generally linked to fuel oil thus LNG prices in Europe tend to be priced against oil. But this is not a hard fast rule. In the Far East, gas prices are set in reference to the Japanese Customs-cleared Crude (JCC) price of a market basket of imported crude to Japan. (When we refer to linkage, it usually means that the price of LNG is some percent of the oil price.)

Because of the large capital requirements of LNG facilities, entities investing in and committing to the trade tend to be large international oil companies or national state-owned oil companies. In North America, the import terminals often have been built by one company which then sells capacity in the terminal to another company or group of companies, much like a pipeline sells capacity to shippers. The capacity-holding companies are large trading organizations that may have a position in the liquefaction plants and who purchase the LNG, transport it, and then sell it in the United States. Exhibit 1 provides a list of the terminals in North America; note the capacity holders in those terminals. Many of these companies will hold capacity in more than one import terminal and swing supplies between markets as prices and specific contracts allow.

There also is a spot LNG trade. Many long-term contracts allow some limited amount of diversion from the designated port of import. Also, with the growth in the world-wide LNG trade over the last 10 years, opportunities arise for spot cargoes and such one-off deals have become more common. Still the market is dominated by long-term commitments in order to support the massive infrastructure developments.

Compared to the North American market, LNG markets lack the short-term flexibility, overall liquidity, and pricing transparency. There is less opportunity for small players to participate in this market. There is no world market "Henry Hub."

Q. What is the role of LNG in the North American market?

Historically, LNG has been on the fringes of North American gas supply, despite the recurring waves of enthusiasm for imports. LNG has never commanded more than a small percentage of the total market. Today, the import terminal boom in North America is over, with most of the terminals seeking to switch to export LNG. This switch is being driven by the excess supply in North America where gas is trading at $2.19 per MMBtu (March 23 price).[4] Compare this with Asian LNG trading between $15.70 and $15.80 per MMBtu, while in Europe, the National Balancing Point in the UK at $8.46 per MMBtu and in other parts of Europe at over $10.00/MMBtu.[5] The existing terminal import capacity in North America will likely operate well below full capacity.

North America nevertheless, may still import LNG from time to time at key locations. The Distrigas facility in Boston is likely to continue to import LNG to supplement winter supplies . New England will likely remain at a premium to Gulf Coast markets. Another feature of the North American market attractive to LNG suppliers is the abundance of storage compared to Europe. Finally, because of the liquidity of the North American market, LNG shipped here can be sold at the prevailing market price. Still, LNG imports

[4] See Platts *Gas Daily*, March 23, 2012.
[5] For the Asian market, Reuters, "Global LNG – Asian LNG Prices near $16/MMBtu," March 23, 2012; http://www.reuters.com/article/2012/03/23/markets-lng-asia-idUSL6E8EN6P420120323. For the NBP price see *Platts European Gas Daily*, March 23, 2012.

to North America will be a challenge, with its abundant gas supply and low prices relative to other markets.

Q. Given the developments in the North American market and LNG markets world-wide, how should NSPI be thinking about gas supply?

In the North American market, the main development, as I described earlier, has been the decline in natural gas prices in the last year due to the abundance of supply from shale resources as well as the lingering effects of the recession and warmer than normal weather. This development will affect the overall price level and could sustain gas prices at levels competitive with coal for a period of time. This competition with coal, in which gas appears to be "winning" for now, is unfolding across the market.

Another trend to be mindful of is the growth in the use of gas in the power sector generally and particularly in New England. Several independent system operators (ISOs) as well as some gas system operators are looking into the interactions between gas and power as power assumes a larger role in the gas market. The concerns focus on two areas. First is the ability of gas systems to supply power generators under peak gas demand conditions when power generators have always relied on interruptible gas supply and transportation. With higher levels of gas use for power generation, the peak demand can occur on both systems at the same time with the firm gas customers having the claim on capacity that power generators do not. Thus there are the implications for reliable power supply. The cure for this is additional pipeline capacity which is costly and may not be recoverable under current ISO market rules.

The other concern about gas system and power system interactions is the effect of intermittent power generation (wind and solar) on the need for firming power which is almost always gas-fired quick start generation. The issue is similar in that these quick start generators, which also provide ancillary services to the grid, can impose large demands on gas systems that may not have the capability to manage the swings absent investment in storage or some other rapidly deployable gas delivery systems. Again, the question turns on who pays for the additional capacity?

Power demand for gas in the Northeast has implications for NSPI. The demand in New England for pipeline capacity and supply to serve New England's power loads and growing peak day loads should increase. The gas system may become more constrained leading to higher gas prices in New England relative to the rest of the market (so called occasional basis "blow-outs.") Eventually one would expect additional pipeline capacity would be built into New England. However, we have seen no proposals to do so nor are we aware of any moves in that direction. More capacity into New England alleviating these constraints, if it is interconnected to M&NP, could open new supply sources for NSPI.

Turning to international LNG markets, we do not see much opportunity for NSPI to secure LNG at prices favourable to NSPI and its customers. Previously I have pointed out current prices for LNG in the European and Asian markets. Under these conditions it is hard to see how any firm supply could be secured on favourable terms. As I noted earlier, North America should see some imports of LNG but these are likely to be erratic, with suppliers responding to specific opportunities to that may present themselves. In all likelihood, North America will become an exporter of LNG.

Q. Are there developments in the Maritimes gas market that also affect gas purchasing by NSPI?

Yes. While the North American and international LNG markets inform NSPI's gas supply options in a general way, the real drivers of NSPI's gas supply environment are developments in the Maritimes. The important development in the Maritimes is the continuing decline in SOEP gas production. The field seems to be plagued with shut-downs and cuts in service. [redacted].

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

The other important development in the Maritimes is the ongoing delays in the start-up of Encana's Deep Panuke production. This is also creating much supply uncertainty.

The declining Maritimes supply also appears to be affecting the gas pricing structure. Previously, buyers in Nova Scotia could assume a cost of incremental gas being something like a Baileyville price (i.e., a price set at the Dracut hub, minus the cost of transportation over M&NP-US). [redacted].

This can be seen in NSPI's most recent round of gas supply solicitation. To meet the expected burn at Tufts Cove through the winter and spring, NSPI solicited bids for incremental gas supply for the 2011-2012 winter (through March 2012) and the April through June of 2012. All of the offers received were for gas delivered to Tufts Cove at prices that were [redacted] to Tufts Cove as described in NSPI's December 2011 "Natural Gas in Review" report for the period Nov. 1, 2010 to Oct. 31, 2011).

[redacted].

Q. Have there been factors that have affected the Dracut price itself recently?

A major factor has been a general lowering of the gas price relative to the historical prices. Dracut has moved down along with the rest of the gas market. Previously I quoted a March 23 price for Henry Hub; the price at Dracut was only $2.28 per MMBtu, less than ten cents higher. The low basis between Henry Hub and Dracut was probably due to the warm winter weather. So, where the pricing structure for Nova Scotia may be changing due to developments in Maritimes gas production, the overall price of gas from New England is much lower (which exacerbates the production challenges in the Maritimes) mitigating the structural changes.

Despite the lower gas prices, constraints on the pipeline system into the Northeast, can under some conditions create large price differences between New England, and by extension, Nova Scotia, relative to the rest of the market. These can have significant effects on the prices paid by buyers in Nova Scotia. For a recent example, in 2010-2011, prices at the various New England hubs diverged from the broader North American market more than they normally do. New England prices have typically been at a premium to the broader market due to the distance from the supply regions and in the winter due to constrained pipeline capacity and bouts of severe weather. Thus the basis (i.e., the price difference between Henry Hub and New England – represented by the hubs at Dracut, Tennessee Zone 6, Algonquin City gates) typically expands in the winter to reflect the higher demand for gas.

In the winter of 2010-2011, this traditional relationship became exaggerated across the region as gas prices at different times in the winter months diverged far more from Henry Hub than historically has been the case. Buyers in the daily markets saw very high prices relative to Henry Hub. This “basis blow-out” appears to have happened for several reasons. First, it was a particularly cold and hard winter, which increased demand. Second, there was a pipeline disruption on TransCanada Pipelines (TCPL) that reduced flows into New York over Iroquois, while there were also some difficulties in getting cargoes into Canaport. Third, the national prices quoted at Henry Hub were influenced by the abundance of gas supplies in the rest of the country such that the usual winter run-up was more moderate than usual. Fourth, high levels of storage also moderated prices elsewhere relative to New England. This pattern did not repeat in the most recent winter (2011-2012). Rather, the major occurrence in the past year has been the weakness in gas prices relative to coal prices and the increase across the market – not only in Nova Scotia – in higher gas consumption by electric generators.

Q. Is NSPI more or less exposed to the effects of these "basis blowouts" than in the past?

With the decline in production from SOEP and the uncertainty of the Deep Panuke supply, NSPI and other Nova Scotian buyers will become more reliant on gas supply from the south. If gas prices continue to be referenced at Dracut[6], then the volatility in New England prices would continue to be reflected in prices to NSPI. However, NSPI has a hedging program to reduce its exposure to price volatility.

The more important point is how the gas pricing structure changes with the decline in Maritimes production. As noted previously, we would expect to see pricing formulas swing from a Dracut minus to a Dracut plus pricing structure. Fundamentally, this would involve a Dracut index plus the costs of transportation to Nova Scotia. Such a price would be something like Dracut index [redacted].

Q. NSPI is using [redacted] for 2013 & 2014 natural gas pricing in this General Rate Application (GRA). In your view, is this reasonable?

The [redacted] structure for the 2013-2014 period is based on the recent bid offerings received by NSPI for the 2011-2012 winter and spring which I discussed previously. Whether this is a reasonable price structure depends on future developments at SOEP and Deep Panuke. [redacted]

[6] There is the possibility that Dracut could cease to be a market hub if volumes from M&NP delivered into the hub decline further. Liquidity could dry up and reporting for prices there could cease.

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

[redacted]. Moreover if there is a more normal winter, gas prices could be stronger and we could see congestion on pipelines into New England. Under these conditions, one might expect something closer to the [redacted] I described.

Q. Does this conclude your testimony?

Yes.

.

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

Exhibit 1. North American LNG Import Terminals

Country	State	Terminal Name	Owner	Re-gas Cap. (Bcfd)	Capacity Held (Bcfd)	Term (Years)	Cap. Utilization	Approved Export to FTAs 2/	Approved: Export to non-FTAs
Mexico	**Tamulipas**	**Altamira**	**Vopak (60%), Engas (40%)**	**0.70**			**10.0%**	**NA**	**NA**
			Shell		0.53	-			
			Total		0.17	-			
Mexico	**Baja CA**	**Energía Costa Azul**	**Sempra LNG**	**1.00 3/**			**1.5%**	**NA**	**NA**
			Shell México Gas Natural		0.50 4/	20			
			Sempra LNG		0.50 5/	-			
US	**MD**	**Cove Point**	**Dominion**	**1.80**			**1.5%**	**X**	**Under Review**
			Statoil Natural Gas, LLC		1.02	20 7/			
			Peaking customers 6/		Varies	Varies			
			BP Energy Company		0.24	20			
			Shell NA LNG, Inc		0.24	20			
			Sempra Energy Trading LLC		0.02	8			
US	**GA**	**Elba Island / Southern LNG**	**El Paso**	**1.80**			**12.6%**	**NA**	**NA**
			BG LNG Services, LLC		0.62	15			
			Shell NA LNG LLC		0.54	30			
			Shell NA LNG LLC (Elba III)		0.40	27			
US	**MA**	**Everett**	**Distrigas of MA LLC (DOMAC)**	**0.70**			**57.1%**	**NA**	**NA**
			GDF SUEZ Energy North America		0.70	-			
US	**TX**	**Freeport**	**Freeport LNG Development LP**	**1.50 8/**			**0.02%**	**X**	**Under Review**
			ConocoPhillips		1.00	-			
			Down Chemical		0.50	20			

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

			Mitsubishi		0.15	-			
			Macquarie		Unspecified	-			
US	**LA**	**Cameron**	**Sempra LNG**	**1.50**			**0.7%**	**X**	**Under Review**
			ENI USA Gas Marketing LLC		0.60	20			
			Sempra LNG Marketing LLC		0.05 9/	1			
US	**LA**	**Lake Charles**	**Tunkline LNG Co, LLC**	**1.80 10/**			**0.00%**	**X**	**Under Review**
			BG LNG Services, LLC		1.75	22			
US	**LA**	**Sabine Pass**	**Cheniere Energy**	**4.00**			**0.1%**	**X**	**X**
			Total		1.00	20			
			Chevron		1.00	20			
			Cheniere Marketing		2.00	-			
Canada	**NB**	**St. John**	**Canaport LNG**	**1.20**			**32.7%**	**NA**	**NA**
			Repsol Energy Canada Ltd.		1.20	-			
US	**TX**	**Golden Pass LNG**	**Qatar Petroleum (70%), ExxonMobil (17.6%), ConocoPhillips (12.4%)**	**2.60**			**0.6%**	**NA**	**NA**
			ConocoPhillips Company		0.79 11/	25			
			Golden Pass LNG Terminal LLC		0.62 11/	25			
			ExxonMobil LNG Supply Company Inc		1.12 11/	25			
US	**MS**	**Pascagoula**	**Gulf LNG Energy LLC**	**1.30**			**0.00%**	**Under Review**	**Under Review**
			ENI		0.56	20			
			Angola LNG Supply Services LLC 12/		>50% of Re-gas Capacity	-			

1/ ICF International. GMM Input.

2/ FTA: Countries with Free Trade Agreements over national treatment of natural gas import/export: Australia, Bahrain, Canada, Chile, Dominica Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Singapore

PARTIALLY CONFIDENTIAL - DO NOT CITE OR QUOTE – PREPARED UNDER DIRECTION OF COUNSEL

4/ Shell México Gas Natural assigned a portion of its reserved capacity at Energía Costa Azul to Gazprom Marketing & Trading Mexico. (Source: Sempra Energy. "Sempra LNG." 2010 Financial Report. pp. 6. http://www.sempra.com/annualreport/img/sempra-2010AR.pdf)

5/ Under a contract to expire in 2022, Sempra LNG sells an average of approximately 0.15 bcfd of natural gas to Comisión Federal de Electricidad (CFE) at prices based on the Southern CA border index. Any gas not sold to CFE is sold to Royal Bank of Scotland (RBS) Sempra Commidities under agreement. (Source: Sempra Energy. "Sempra LNG." 2010 Financial Report. pp. 6. http://www.sempra.com/annualreport/img/sempra-2010AR.pdf)

6/ Peaking customers include: Atlanta Gas Light Co, Public Service Company of NC, Inc, Virginia Natural Gas, Washington Gas Light

7/ 0.78 bcfd of the reserved firm transportation service (FTS) is from Mar 26, 2009 to Dec 31, 2020.

8/ Peak send-out capacity is over 2.0 bcfd. (Source: Freeport LNG. "Regasification terminal technology." http://www.freeportlng.com/regas_technology.asp)

9/ Volume obtained from FERC. Cameron Interstate Pipeline, LLC. Index of Customers. http://www.ferc.gov/docs-filing/forms/form-549b/data.asp

10/ Natural gas peak sendout capability: up to 2.1 bcfd (Source: Panhandle Energy. "Flexible LNG Services." Trunkline LNG Company. http://www.panhandleenergy.com/serv_lng.asp)

11/ Re-gasification capacity by capacity holder estimated by Index of Customers for Golden Pass Pipeline LLC, owner of the Golden Pass Pipeline: 69-mile long, FERC-regulated interstate pipeline originating at Golden Pass LNG Terminal and interconnects to intrastate and interstate pipelines.

12/ Angola LNG is owned by affiliates of Sonagas, Chevron, BP, Total, and ENI.

Appendix E
Operating Costs
Line-by-Line Account and Variance Analysis

NOVA SCOTIA POWER INC.
REGULATED OPERATING COSTS
FOR THE YEARS 2011 THROUGH 2014

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*% of Total OM&G*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2012 Forecast*	*2013 Fct. Vs. 2011 Actual*	*2013 Fct. Vs. 2014 Forecast*
Executive Management	1,252	1,179	[redacted]	1,147	1,160	0.4%	(105)	[redacted]	(32)	13
Corporate Office of Secretary and General Counsel	7,481	7,079	[redacted]	8,530	8,833	3.1%	1,049	[redacted]	1,451	303
Corporate Finance	5,666	5,691	[redacted]	6,466	6,571	2.3%	800	[redacted]	775	105
Investor Relations, Communications and Public Affairs	2,433	2,063	[redacted]	2,360	2,394	0.8%	(73)	[redacted]	297	34
Corporate Human Resources (including Safety)	5,206	4,766	[redacted]	5,554	5,648	2.0%	348	[redacted]	788	94
Facilities and Procurement	8,947	11,886	[redacted]	9,991	10,122	3.6%	1,044	[redacted]	(1,895)	131
Information Technology	10,500	10,746	[redacted]	11,737	12,126	4.2%	1,237	[redacted]	991	389
Regulatory Affairs	5,854	6,518	[redacted]	6,332	6,236	2.3%	478	[redacted]	(186)	(96)
TOTAL CORPORATE GROUPS	**47,339**	**49,928**	[redacted]	**52,117**	**53,090**	18.7%	**4,778**	[redacted]	**2,189**	**973**
TECHNICAL & CONSTRUCTION SERVICES	**13,290**	**13,605**	[redacted]	**14,431**	**14,550**	5.2%	**1,141**	[redacted]	**826**	**119**
SUSTAINABILITY	**1,970**	**3,188**	[redacted]	**1,508**	**1,527**	0.5%	**(462)**	[redacted]	**(1,680)**	**19**
Head Office	16,911	15,064	[redacted]	24,740	23,950	8.9%	7,829	[redacted]	9,676	(790)
Thermal Plants	66,326	72,793	[redacted]	61,995	63,479	22.2%	(4,331)	[redacted]	(10,798)	1,484
Combustion Turbines	1,316	1,384	[redacted]	1,272	1,301	0.5%	(44)	[redacted]	(112)	29
Hydro & Wind Energy	14,810	12,685	[redacted]	14,390	14,707	5.2%	(420)	[redacted]	1,705	317
Biomass	-	-	[redacted]	5,380	6,261	1.9%	5,380	[redacted]	5,380	881
Energy, Fuels and Risk Management	3,816	3,328	[redacted]	3,819	3,909	1.4%	3	[redacted]	491	90
TOTAL POWER PRODUCTION	**103,179**	**105,254**	[redacted]	**111,596**	**113,607**	40.0%	**8,417**	[redacted]	**6,342**	**2,011**
Regional Operations	23,310	24,643	[redacted]	22,542	23,094	8.1%	(769)	[redacted]	(2,101)	552
Control Center	8,062	7,318	[redacted]	7,996	8,194	2.9%	(66)	[redacted]	678	198
Reliability and Transmission & Workforce Management	16,665	18,275	[redacted]	22,382	22,866	8.0%	5,717	[redacted]	4,107	484
Administration (incl Storm)	17,436	18,823	[redacted]	26,331	26,315	9.4%	8,895	[redacted]	7,508	(16)
TOTAL CUSTOMER OPERATIONS	**65,473**	**69,059**	[redacted]	**79,251**	**80,469**	28.4%	**13,777**	[redacted]	**10,192**	**1,218**
CUSTOMER SERVICE	**32,404**	**39,932**	[redacted]	**37,026**	**37,358**	13.3%	**4,622**	[redacted]	**(2,906)**	**332**
Corporate Adjustments	(17,958)	(19,573)	[redacted]	(16,895)	(17,507)	-6.1%	1,063	[redacted]	2,678	(612)
TOTAL CORPORATE ADJUSTMENTS	**(17,958)**	**(19,573)**	[redacted]	**(16,895)**	**(17,507)**	-6.1%	**1,063**	[redacted]	**2,678**	**(612)**
TOTAL REGULATED OPERATING COSTS	**245,697**	**261,393**	[redacted]	**279,034**	**283,094**	100.0%	**33,336**	[redacted]	**17,641**	**4,060**

Executive Management

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Actual	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	**537**	**558**	[redacted]	**547**	**562**	**10**	**(11)**	[redacted]	**15**
010 Office Supplies	8	5	[redacted]	8	8	-	3	[redacted]	-
011 Travel Expense	55	35	[redacted]	56	57	1	21	[redacted]	1
012 Materials	-	1	[redacted]	-	-	-	(1)	[redacted]	-
013 Contracts	5	4	[redacted]	5	5	-	1	[redacted]	-
015 Frt, Post & Delivery	1	1	[redacted]	1	1	-	-	[redacted]	-
021 Telephones	8	8	[redacted]	8	8	-	-	[redacted]	-
028 Consulting	204	123	[redacted]	107	109	(97)	(16)	[redacted]	2
029 Membership Dues	194	202	[redacted]	96	98	(98)	(106)	[redacted]	2
041 Meals & Entertainment	69	53	[redacted]	70	72	1	17	[redacted]	2
042 Employee Benefits	154	162	[redacted]	230	221	76	68	[redacted]	(9)
056 Training & Development	5	3	[redacted]	5	6	-	2	[redacted]	1
066 Other Goods & Services	12	24	[redacted]	14	13	2	(10)	[redacted]	(1)
Total Non-Labour	***715***	***621***	[redacted]	***600***	***598***	***(115)***	***(21)***	[redacted]	***(2)***
Total	***1,252***	***1,179***	[redacted]	***1,147***	***1,160***	***(105)***	***(32)***	[redacted]	***13***

Responsibility Area Corporate Groups Executive Management	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	1,147	1,160	1,252	1,179	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Executive Management is responsible for providing corporate leadership and strategic direction to ensure that the Company provides low cost reliable service to customers and a reasonable return to investors.	13	(105)	(32)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Other variations**	13			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Consulting** decrease due to end of consulting contract in March 2012		(97)		
> **Membership Dues** decrease due to NSPI discontinuing memberships with two organizations		(98)		
> **Employee Benefits** increase due to increased pension expense		76		
> **Other variations**		14		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Membership Dues** decrease due to NSPI discontinuing memberships with two organizations			(106)	
> **Employee Benefits** increase due to increased pension expense			68	
> **Other variations**			6	
2013 Forecast vs. 2012 Forecast (Thousands of $)				
> **Other variations**				[redacted]

Corporate Secretary and General Counsel

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	1,251	1,167	[redacted]	1,286	1,322	35	119	[redacted]	36
010 Office Supplies	12	9	[redacted]	12	12	(0)	3	[redacted]	-
011 Travel Expense	62	18	[redacted]	64	64	2	46	[redacted]	-
012 Materials	-	1	[redacted]	-	-	-	(1)	[redacted]	-
013 Contracts	6	5	[redacted]	4	4	(2)	(1)	[redacted]	-
015 Frt, Post & Delivery	16	9	[redacted]	16	16	0	7	[redacted]	-
021 Telephones	15	25	[redacted]	15	15	(0)	(10)	[redacted]	-
027 Corporate Filing Fees	122	116	[redacted]	125	127	3	9	[redacted]	2
028 Consulting	-	426	[redacted]	-	-	-	(426)	[redacted]	-
029 Membership Dues	35	22	[redacted]	36	36	1	14	[redacted]	-
032 Subscrpt/Info.Software	17	15	[redacted]	17	18	(0)	2	[redacted]	1
033 Rental/Mtnce equipment/software	20	-	[redacted]	20	20	-	20	[redacted]	-
034 Appl. Software	-	17	[redacted]	-	-	-	(17)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	-	52	[redacted]	-	-	-	(52)	[redacted]	-
036 Directors' Fees & Exp	1,010	852	[redacted]	1,108	1,126	98	256	[redacted]	18
037 Ext. Legal & Audit	487	477	[redacted]	499	507	12	22	[redacted]	8
038 Annual Shareholder Meeting	256	40	[redacted]	262	266	6	222	[redacted]	4
041 Meals & Entertainment	45	52	[redacted]	46	47	1	(6)	[redacted]	1
042 Employee Benefits	353	301	[redacted]	531	512	178	230	[redacted]	(19)
043 Insurance	4,400	4,146	[redacted]	5,145	5,402	745	999	[redacted]	257
056 Training & Development	17	19	[redacted]	17	17	0	(2)	[redacted]	-
057 Corp. Support Transfer	(654)	(715)	[redacted]	(687)	(695)	(33)	28	[redacted]	(8)
066 Other Goods & Services	11	25	[redacted]	14	17	3	(11)	[redacted]	3
Total Non-Labour	***6,230***	***5,912***	[redacted]	***7,244***	***7,511***	***1,014***	***1,332***	[redacted]	***267***
Total	***7,481***	***7,079***	[redacted]	***8,530***	***8,833***	***1,049***	***1,451***	[redacted]	***303***

Forecasts are compiled for purposes of the Rate Application and are not intended to be relied upon for other purposes.

Responsibility Area Corporate Groups Corporate Secretary and General Counsel	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	8,530	8,833	7,481	7,079	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
The office of the Corporate Secretary and General Counsel provides corporate secretarial, legal and risk management (insurance and claims) services to the Company.	303	1,049	1,451	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Insurance** increase due to increased premiums	257			
> **Other variations**	46			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Insurance** increase due to increased premiums		745		
> **Directors' Fees and Expenses** increase due to increased allowances per individual members		98		
> **Employee Benefits** increase due to increased pension expense		178		
> **Other variations**		28		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** increase due to staff complement changes			119	
> **Consulting** decrease due to completion of the Paperless Office Project in 2011			(426)	
> **Insurance** increase due to increased premiums			999	
> **Employee Benefits** increase due to increased pension expense			230	
> **Computer Hardware and Operating Software** decrease due to completion of the Paperless Office Project in 2011			(52)	
> **Annual Shareholder Meeting** increase due to increased associated costs			222	
> **Directors' Fees and Expenses** increase due to increased allowances per individual members			256	
> **Other variations**			103	
2013 Forecast vs. 2012 Forecast (Thousands of $)				[redacted]
> **Insurance** increase due to increased premiums				
> **Directors' Fees and Expenses** increase due to increased allowances per individual members				
> **Employee Benefits** increase due to increased pension expense				
> **Other variations**				

Corporate Finance

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	**4,889**	**4,726**	[redacted]	**5,869**	**6,160**	**980**	**1,143**	[redacted]	**291**
			[redacted]					[redacted]	-
010 Office Supplies	61	58	[redacted]	60	61	(1)	2	[redacted]	1
011 Travel Expense	130	153	[redacted]	193	197	63	40	[redacted]	4
012 Materials	4	6	[redacted]	5	5	1	(1)	[redacted]	-
013 Contracts	415	447	[redacted]	427	434	12	(20)	[redacted]	7
015 Frt, Post & Delivery	1	1	[redacted]	1	1	-	-	[redacted]	-
016 Tools & Equipment	-	20	[redacted]	31	31	31	11	[redacted]	-
021 Telephones	49	22	[redacted]	50	51	1	28	[redacted]	1
028 Consulting	286	500	[redacted]	279	295	(7)	(221)	[redacted]	16
029 Membership Dues	32	39	[redacted]	45	47	13	6	[redacted]	2
032 Subscrpt/Info.Software	65	59	[redacted]	75	77	10	16	[redacted]	2
033 Rental/Mtnce equipment/software	20	20	[redacted]	21	21	1	1	[redacted]	-
034 Appl. Software	3	12	[redacted]	3	3	-	(9)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	1	11	[redacted]	6	6	5	(5)	[redacted]	-
037 Ext. Legal & Audit	330	522	[redacted]	338	344	8	(184)	[redacted]	6
041 Meals & Entertainment	47	45	[redacted]	53	55	6	8	[redacted]	2
042 Employee Benefits	1,340	1,486	[redacted]	2,426	2,388	1,086	940	[redacted]	(38)
052 Non Reg.Cost Recovery	-	(5)	[redacted]	-	-	-	5	[redacted]	-
056 Training & Development	117	59	[redacted]	142	141	25	83	[redacted]	(1)
066 Other Goods & Services	33	14	[redacted]	27	27	(6)	13	[redacted]	-
051 Gen.Cost Recovery	(264)	(289)	[redacted]	(271)	(275)	(7)	18	[redacted]	(4)
057 Corp. Support Transfer	(1,893)	(2,215)	[redacted]	(3,314)	(3,498)	(1,421)	(1,099)	[redacted]	(184)
Total Non-Labour	***777***	***965***	[redacted]	***597***	***411***	***(180)***	***(368)***	[redacted]	***(186)***
Total	***5,666***	***5,691***	[redacted]	***6,466***	***6,571***	***800***	***775***	[redacted]	***105***

Responsibility Area Corporate Groups Corporate Finance	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	6,466	6,571	5,666	5,691	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Corporate Finance includes costs for the activities of : Finance, Corporate & Capital Accounting, Tax Planning and Compliance, Internal Audit, Security, Risk Management and Treasury.	105	800	775	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Labour** increase due to labour escalations and an additional FTE partially recovered from affiliates through corporate support transfers	291			
> **Corporate Support Transfer** increase due to increased affiliate allocations.	(184)			
> **Other Variations**	(2)			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** increase due to labour escalations, new positions and staff complement changes in 2013 partially recovered from affiliates through corporate support transfers		980		
> **Travel** increase due to increased activity in Internal Audit and Tax		63		
> **Employee Benefits** increase due to increased pension costs		1,086		
> **Corporate Support Transfer** increase due to increased affiliate allocations.		(1,421)		
> **Other variations**		92		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** increase due to labour escalations and new positions in Security and Tax partially recovered from affiliates through corporate support transfers			1,143	
> **Consulting** decrease due to higher costs in 2011 for US GAAP project			(221)	
> **External Legal & Audit** decrease due to higher costs in 2011 for US GAAP project			(184)	
> **Employee Benefits** increase due to increased pension costs			940	
> **Training & Development** increase due to higher anticipated costs			83	
> **Corporate Support Transfer** increase due to increased affiliate allocations.			(1,099)	
> **Other variations**			113	
2013 Forecast vs. 2012 Forecast (Thousands of $)				[redacted]
> **Labour** increase due to labour escalations and new positions in Security and Tax partially recovered from affiliates through corporate support transfers				
> **Employee Benefits** increase due to increased pension costs				
> **Corporate Support Transfer** increase due to increased affiliate allocations				
> **Other variations**				

Investor Relations, Communications & Public Affairs

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	793	661	[redacted]	787	809	(6)	126	[redacted]	22
			[redacted]					[redacted]	
010 Office Supplies	5	6	[redacted]	5	5	-	(1)	[redacted]	-
011 Travel Expense	51	22	[redacted]	42	43	(9)	20	[redacted]	1
012 Materials	7	31	[redacted]	7	7	-	(24)	[redacted]	-
013 Contracts	145	33	[redacted]	133	135	(12)	100	[redacted]	2
014 Overtime Meals	-	2	[redacted]	-	-	-	(2)	[redacted]	-
015 Frt, Post & Delivery	4	2	[redacted]	4	4	-	2	[redacted]	-
020 Royalties/Easements/Appraisals	20	-	[redacted]	-	-	(20)	-	[redacted]	-
021 Telephones	-	14	[redacted]	21	21	21	7	[redacted]	-
028 Consulting	737	719	[redacted]	745	760	8	26	[redacted]	15
029 Membership Dues	6	7	[redacted]	6	6	-	(1)	[redacted]	-
032 Subscrpt/Info.Software	6	73	[redacted]	6	6	-	(67)	[redacted]	-
034 Appl. Software	7	15	[redacted]	7	7	-	(8)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	10	-	[redacted]	10	10	-	10	[redacted]	-
040 Advertising	365	214	[redacted]	220	224	(145)	6	[redacted]	4
041 Meals & Entertainment	25	21	[redacted]	21	21	(4)	-	[redacted]	-
042 Employee Benefits	242	225	[redacted]	331	319	89	106	[redacted]	(12)
056 Training & Development	10	4	[redacted]	15	16	5	11	[redacted]	1
066 Other Goods & Services	-	14	[redacted]	-	1	-	(14)	[redacted]	1
Total Non-Labour	***1,640***	***1,402***	[redacted]	***1,573***	***1,585***	***(67)***	***171***	[redacted]	***12***
			[redacted]					[redacted]	
Total	***2,433***	***2,063***	[redacted]	***2,360***	***2,394***	***(73)***	***297***	[redacted]	***34***

Responsibility Area Corporate Groups Investor Relations and Communications & Public Affairs	2013 Forecast	2012 Forecast	2011 Actual	2012 Compliance	2014 Forecast
	2,360	[redacted]	2,063	2,433	2,394
Overview			**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Compliance**	**2014 Forecast vs. 2013 Forecast**
Communications & Public Affairs and Investor Relations provides all public affairs, investor and government relations for the Company.			297	(73)	34
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Other Variances**					34
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Employee Benefits** increase due to increased pension costs				89	
> **Advertising** decrease due to planned reductions				(145)	
> **Other variations**				(17)	
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalations and full staff complement.			126		
> **Contracts** increase due to increased activity, CISION costs being forecasted as contracts in 2013, and new contracts for [redacted]			100		
> **Employee Benefits** increase due to increased pension costs			106		
> **Subscription/Information Software** decrease due to CISION being included in 2011 costs as Subscriptions but is now budgeted as contracts expense.			(67)		
> **Other variations**			32		
2013 Forecast vs. 2012 Forecast (Thousands of $)					
> **Other variations**		[redacted]			

Human Resources

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	2,783	2,791	[redacted]	2,935	3,017	152	144	[redacted]	82
010 Office Supplies	21	18		18	18	(3)	-		-
011 Travel Expense	284	253		308	313	24	55		5
012 Materials	186	103		110	112	(76)	7		2
013 Contracts	540	597		594	604	54	(3)		10
014 Overtime Meals	3	-		-	-	(3)	-		-
015 Frt, Post & Delivery	-	1		-	-	-	(1)		-
021 Telephones	52	36		42	43	(10)	6		1
028 Consulting	561	439		585	605	24	146		20
029 Membership Dues	26	9		24	24	(2)	15		-
032 Subscrpt/Info.Software	3	2		3	3	-	1		-
033 Rental/Mtnce equipment/software	55	41		62	63	7	21		1
035 Comp.Hrdwr & Op.Sftwr	5	(2)		5	5	-	7		-
037 Ext. Legal & Audit	123	30		139	142	16	109		3
040 Advertising	10	8		12	12	2	4		-
041 Meals & Entertainment	168	129		176	179	8	47		3
042 Employee Benefits	766	818		1,143	1,101	377	325		(42)
045 Pensioner Benefits	98	93		101	103	3	8		2
052 Non Reg.Cost Recovery	-	(4)		-	-	-	4		-
056 Training & Development	40	59		46	67	6	(13)		21
057 Corp. Support Transfer	(522)	(592)		(748)	(761)	(226)	(156)		(13)
066 Other Goods & Services	4	(63)		(1)	(2)	(5)	62		(1)
Total Non-Labour	***2,423***	***1,975***		***2,619***	***2,631***	***196***	***644***		***12***
Total	***5,206***	***4,766***		***5,554***	***5,648***	***348***	***788***		***94***

Responsibility Area Corporate Groups Human Resources	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	5,554	5,648	5,206	4,766	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Human Resources team supports all employees in the areas of employee and industrial relations, training, apprenticeship, performance management, safety, pension, benefits, wellness administration, recruitment and payroll.		94	348	788	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		82			
> **Employee Benefits** decrease due to decreased pension expense		(42)			
> **Other Variations**		54			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to labour escalation and increased Term Labour			152		
> **Materials** decrease due to decreased activity, partially offset by increased use of contracts			(76)		
> **Contracts** increase due to increased activity, partially offset by reduced materials			54		
> **Employee Benefits** increase due to increased pension expense			377		
> **Corporate Support Transfer** increase due to increased affiliate allocations.			(226)		
> **Other variations**			67		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalation and changes in staff complement				144	
> **Travel** increase due to increased activity				55	
> **Meals & Entertainment** increase due to increased activity and increased travel				47	
> **Consulting** increase due increased activity including Employee Files system upgrade.				146	
> **Employee Benefits** increase due to increased pension costs				325	
> **Corporate Support Transfer** increase due to increased affiliate allocations.				(156)	
> **External Legal and Audit** increase due to collective bargaining activity				109	
> **Other Goods and Services** increase due to cost escalations				62	
> **Other variations**				56	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalation and change in staff complement					
> **Employee Benefits** increase due to increased pension costs					
> **Other variations**					

Facilities, Procurement and Purchasing

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	4,895	4,521	[redacted]	5,022	5,162	127	501	[redacted]	140
010 Office Supplies	15	44	[redacted]	15	15	-	(29)	[redacted]	-
011 Travel Expense	95	158	[redacted]	97	99	2	(61)	[redacted]	2
012 Materials	116	133	[redacted]	119	121	3	(14)	[redacted]	2
013 Contracts	2,787	2,472	[redacted]	2,857	2,904	70	385	[redacted]	47
014 Overtime Meals	1	-	[redacted]	1	1	-	1	[redacted]	-
015 Frt, Post & Delivery	257	566	[redacted]	263	267	6	(303)	[redacted]	4
019 Water	36	75	[redacted]	37	37	1	(38)	[redacted]	-
021 Telephones	48	49	[redacted]	50	50	2	1	[redacted]	-
028 Consulting	10	272	[redacted]	10	10	-	(262)	[redacted]	-
029 Membership Dues	7	3	[redacted]	7	7	-	4	[redacted]	-
032 Subscrpt/Info.Software	2	1	[redacted]	3	3	1	2	[redacted]	-
033 Rental/Mtnce equipment/software	1	3	[redacted]	1	1	-	(2)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	1	11	[redacted]	1	1	-	(10)	[redacted]	-
041 Meals & Entertainment	23	39	[redacted]	23	24	-	(16)	[redacted]	1
042 Employee Benefits	1,298	1,248	[redacted]	1,953	1,882	655	705	[redacted]	(71)
044 Energy Use (Non-Elect	211	85	[redacted]	216	219	5	131	[redacted]	3
046 Energy Use	-	235	[redacted]	-	-	-	(235)	[redacted]	-
050 Rent	90	3,091	[redacted]	93	94	3	(2,998)	[redacted]	1
052 Non Reg.Cost Recovery	(1,139)	(1,054)	[redacted]	(1,409)	(1,432)	(270)	(355)	[redacted]	(23)
056 Training & Development	59	66	[redacted]	61	62	2	(5)	[redacted]	1
058 Personal Equipment	13	10	[redacted]	14	14	1	4	[redacted]	-
061 Write-offs	50	(274)	[redacted]	51	52	1	325	[redacted]	1
062 Recoveries	-	(406)	[redacted]	-	-	-	406	[redacted]	-
066 Other Goods & Services	5	58	[redacted]	5	8	-	(53)	[redacted]	3
091 Tax Assessment	-	346	[redacted]	-	-	-	(346)	[redacted]	-
051 Gen.Cost Recovery	(1,110)	(1,048)	[redacted]	(705)	(705)	405	343	[redacted]	-
083 Short-term interest	1,201	1,183	[redacted]	1,231	1,251	30	48	[redacted]	20
190 Miscellaneous Revenue and Recoveries	(25)	(1)	[redacted]	(25)	(25)	-	(24)	[redacted]	-
Total Non-Labour	***4,052***	***7,365***	[redacted]	***4,969***	***4,960***	***917***	***(2,396)***	[redacted]	***(9)***
Total	***8,947***	***11,886***	[redacted]	***9,991***	***10,122***	***1,044***	***(1,895)***	[redacted]	***131***

Responsibility Area Corporate Groups Facilities & Procurement	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	9,991	10,122	8,947	11,886	[redacted]
Overview Facilities and Procurement provide related services to operating groups. The Procurement group is involved in the sourcing of approximately $80M of operating expenditures annually. The Facilities group is responsible for management of all land & facilities not directly associated with the production or delivery of energy.		**2014 Forecast vs. 2013 Forecast** 131	**2013 Forecast vs. 2012 Compliance** 1,044	**2013 Forecast vs. 2011 Actual** (1,895)	**2013 Forecast vs. 2012 Forecast** [redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		140			
> **Contracts** increase due to cost escalation.		47			
> **Employee Benefits** decrease due to decreased pension costs.		(71)			
> **Other variations**		15			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to labour escalations			127		
> **Contracts** increase due to cost escalation.			70		
> **Employee Benefits** increase due to increased pension costs			655		
> **Non-regulated Cost Recovery** increased recovery from affiliate rent in Lower Water Street.			(270)		
> **General Cost recovery** decreased recovery due to leases expiring			405		
> **Other variations**			57		

Responsibility Area Corporate Groups Facilities & Procurement	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	9,991	10,122	8,947	11,886	[redacted]
Overview Facilities and Procurement provide related services to operating groups. The Procurement group is involved in the sourcing of approximately $80M of operating expenditures annually. The Facilities group is responsible for management of all land & facilities not directly associated with the production or delivery of energy.		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
		131	1,044	(1,895)	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalations and new positions in restructuring.				501	
> **Travel** decrease due to lower travel requirements than 2011.				(61)	
> **Contracts** increase due to full twelve months in Lower Water Street in 2012 as opposed to three months in 2011.				385	
> **Freight, Postage and Delivery** decrease due to new [redacted] agreement, 2011 close outs with [redacted] contract.				(303)	
> **Water** decrease due to move to LWS. Filtered water is now available instead of bottled water.				(38)	
> **Consulting** decrease due to 2011 consultants working on process improvements and Procurement and Inventory Management Assessment.				(262)	
> **Employee Benefits** increase due to increased pension costs				705	
> **Energy Use** decrease due to move to Lower Water Street				(104)	
> **Rent** decrease due to move to Lower Water Street.				(2,998)	
> **Non-regulated Cost Recovery** increased recovery due to increased revenue from affiliate occupied space in Lower Water Street				(355)	
> **Write-offs** increase due to write-off of inventory with implementation of work management system.				325	
> **Recoveries** decrease due to receipt of credits in 2011 from suppliers not forecasted for 2013.				406	
> **Other Goods & Services** decrease due to allocation of costs in 2013.				(53)	
> **Tax Assessment** decrease due to move to Lower Water Street.				(346)	
> **General Cost recovery** decreased recovery due to leases expiring and move to Lower Water Street.				343	
> **Other variations**				(40)	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalation					
> **Contracts** increase due to cost escalation					
> **Employee Benefits** increase due to increased pension costs					
> **Other variations**					

Information Technology

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	2,812	2,914	[redacted]	2,982	3,066	170	68	[redacted]	84
010 Office Supplies	3	3		3	3	-	-		-
011 Travel Expense	34	41		34	35	-	(7)		1
012 Materials	1	10		1	1	-	(9)		-
013 Contracts	3,259	3,392		3,341	3,396	82	(51)		55
015 Frt, Post & Delivery	2	1		2	2	-	1		-
021 Telephones	14	(218)		14	14	-	232		-
023 Data Communication Circuits	1,356	1,376		1,440	1,514	84	64		74
028 Consulting	258	193		265	269	7	72		4
029 Membership Dues	1	2		1	1	-	(1)		-
033 Rental/Mtnce equipment/software	2,464	2,768		2,991	3,290	527	223		299
034 Appl. Software	3	7		4	4	1	(3)		-
035 Comp.Hrdwr & Op.Sftwr	2	-		2	2	-	2		-
041 Meals & Entertainment	16	27		16	16	-	(11)		-
042 Employee Benefits	768	843		1,205	1,161	437	362		(44)
052 Non Reg.Cost Recovery	(556)	(610)		(630)	(715)	(74)	(20)		(85)
056 Training & Development	63	55		65	66	2	10		1
066 Other Goods & Services	13	11		15	15	2	4		-
051 Gen.Cost Recovery	(13)	(69)		(14)	(14)	(1)	55		-
Total Non-Labour	7,688	7,832		8,755	9,060	1,067	923		305
Total	***10,500***	***10,746***		***11,737***	***12,126***	***1,237***	***991***		***389***

Responsibility Area Corporate Groups Information Technology	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	11,737	12,126	10,500	10,746	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Information Technology department provides related support services and equipment to all NSPI operating groups.		389	1,237	991	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		84			
> **Contracts in**crease due to increased use of support services		55			
> **Data Communication Circuits** increase due to increased use of bandwidth		74			
> **Rental / Maintenance Equipment / Software** increase due to support of new application software		299			
> **Employee Benefits de**crease due to decreased pension costs		(44)			
> **Non Reg. Cost Recovery** increased recovery due to increase use of IT services from affiliates		(85)			
> **Other variations**		6			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to labour escalations and succession planning for Manager: Security and Planning and new IT infrastructure planning role			170		
> **Contracts** increase due to increased use of support services			82		
> **Data Communication Circuits** increase due to increased use of bandwidth			84		
> **Rental / Maintenance Equipment / Software** increase due to support of new application software			527		
> **Employee Benefits** increase due to increased pension costs			437		
> **Non-Regulated Cost Recovery** increase recovery due to increased use of IT services from affiliates			(74)		
> **Other variations**			11		

Responsibility Area Corporate Groups Information Technology	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	11,737	12,126	10,500	10,746	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Information Technology department provides related support services and equipment to all NSPI operating groups.	389	1,237	991	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** increase due to labour escalations			68	
> **Contracts** decrease due to decreased usage of desktop services			(51)	
> **Telephones** increase due to a one time credit received in 2011 on new contract			232	
> **Data Communications Circuits** increase due to increased use of bandwidth			64	
> **Consulting** increase due to support of applications and interfaces and hardware			72	
> **Rental / Maintenance Equipment / Software** increase due to support of new application software			223	
> **Employee Benefits** increase due to increased pension costs			362	
> **General Cost recovery** decreased recovery due to lower expected general recovery of IT services from affiliates			55	
> **Other variations**			(34)	
2013 Forecast vs. 2012 Forecast (Thousands of $)				[redacted]
> **Labour** increase due to labour escalations, succession planning for IT Security and new IT infrastructure planning role				
> **Contracts** increase due to increased use of support services				
> **Data Communications Circuits** increase due to increased use of bandwidth				
> **Rental / Maintenance Equipment / Software** increase due to support of new application software				
> **Employee Benefits** increase due to increased pension costs				
> **Non-Regulated Cost Recovery** increase due to increased use of IT services from affiliates				
> **Other variations**				

Regulatory Affairs

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	1,533	1,348	[redacted]	1,491	1,509	(42)	143	[redacted]	18
010 Office Supplies	2	2	[redacted]	3	3	1	1	[redacted]	-
011 Travel Expense	33	30	[redacted]	34	35	1	4	[redacted]	1
012 Materials	11	37	[redacted]	11	11	-	(26)	[redacted]	-
015 Frt, Post & Delivery	3	2	[redacted]	3	3	-	1	[redacted]	-
021 Telephones	13	8	[redacted]	13	13	-	5	[redacted]	-
028 Consulting	2,060	3,085	[redacted]	2,352	2,238	292	(733)	[redacted]	(114)
029 Membership Dues	11	6	[redacted]	12	12	1	6	[redacted]	-
032 Subscrpt/Info.Software	-	1	[redacted]	-	-	-	(1)	[redacted]	-
033 Rental/Mtnce equipment/software	2	-	[redacted]	2	2	-	2	[redacted]	-
034 Appl. Software	16	13	[redacted]	17	17	1	4	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	1	1	[redacted]	1	1	-	-	[redacted]	-
037 Ext. Legal & Audit	1,584	1,474	[redacted]	1,625	1,651	41	151	[redacted]	26
040 Advertising	40	15	[redacted]	41	41	1	26	[redacted]	-
041 Meals & Entertainment	29	47	[redacted]	29	30	-	(18)	[redacted]	1
042 Employee Benefits	428	405	[redacted]	610	579	182	205	[redacted]	(31)
052 Non Reg.Cost Recovery	-	(3)	[redacted]	-	-	-	3	[redacted]	-
056 Training & Development	33	14	[redacted]	34	35	1	20	[redacted]	1
066 Other Goods & Services	55	33	[redacted]	54	56	(1)	21	[redacted]	2
Total Non-Labour	4,321	5,170	[redacted]	4,841	4,727	520	(329)	[redacted]	(114)
Total	***5,854***	***6,518***	[redacted]	***6,332***	***6,236***	***478***	***(186)***	[redacted]	***(96)***

Responsibility Area Corporate Groups Regulatory Affairs	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	6,332	6,236	5,854	6,518	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Regulatory Affairs includes the resources responsible for regulatory compliance and management.	(96)	478	(186)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Consulting** decrease due to 2013 Renewable Energy Administrator (REA) costs not continuing in 2014.	(114)			
> **Other variations**	18			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Consulting** increase primarily due to Cost of Service and REA related costs, partially offset by 2012 FAM Audit costs.		292		
> **Employee Benefits** increase due to increased pension costs		182		
> **Other variations**		4		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** increase due to full year of staff complement and escalation.			143	
> **Consulting** decrease due to 2011 Load Retention Tariff hearing, COMFIT and Depreciation Settlement, partially offset by anticipated Cost of Service costs.			(733)	
> **External Legal & Audit** increase due to cost escalation.			151	
> **Employee Benefits** increase due to increased pension costs			205	
> **Other variations**			48	
2013 Forecast vs. 2012 Forecast (Thousands of $)				[redacted]
> **Consulting** increase primarily due to Cost of Service Initiative				
> **Employee Benefits** increase due to increased pension costs				
> **Other variations**				

Technical & Construction Services

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	8,720	8,458	[redacted]	8,865	9,088	144	407	[redacted]	223
010 Office Supplies	33	22	[redacted]	34	34	1	12	[redacted]	-
011 Travel Expense	572	458	[redacted]	564	573	(8)	106	[redacted]	9
012 Materials	173	156	[redacted]	173	176	-	17	[redacted]	3
013 Contracts	530	670	[redacted]	556	565	26	(114)	[redacted]	9
014 Overtime Meals	1	1	[redacted]	1	1	-	-	[redacted]	-
015 Frt, Post & Delivery	22	17	[redacted]	23	23	1	6	[redacted]	-
016 Tools & Equipment	53	12	[redacted]	55	55	2	43	[redacted]	-
017 Chemicals	7	6	[redacted]	8	8	1	2	[redacted]	-
021 Telephones	114	139	[redacted]	138	140	24	(1)	[redacted]	2
025 Leasing	1	-	[redacted]	1	1	-	1	[redacted]	-
028 Consulting	185	349	[redacted]	172	175	(13)	(177)	[redacted]	3
029 Membership Dues	99	176	[redacted]	102	104	3	(74)	[redacted]	2
031 Fleet Fuel	25	35	[redacted]	26	27	1	(9)	[redacted]	1
032 Subscrpt/Info.Software	12	6	[redacted]	13	13	1	7	[redacted]	-
033 Rental/Mtnce equipment/software	112	55	[redacted]	115	117	3	60	[redacted]	2
034 Appl. Software	49	41	[redacted]	50	51	1	9	[redacted]	1
035 Comp.Hrdwr & Op.Sftwr	17	5	[redacted]	18	19	1	13	[redacted]	1
037 Ext. Legal & Audit	-	492	[redacted]	-	-	-	(492)	[redacted]	-
041 Meals & Entertainment	185	160	[redacted]	159	162	(26)	(1)	[redacted]	3
042 Employee Benefits	2,506	2,531	[redacted]	3,555	3,416	1,049	1,024	[redacted]	(139)
050 Rent	12	15	[redacted]	13	13	1	(2)	[redacted]	-
052 Non Reg.Cost Recovery	-	(189)	[redacted]	-	-	-	189	[redacted]	-
056 Training & Development	105	79	[redacted]	111	113	6	32	[redacted]	2
057 Corp. Support Transfer	(162)	(122)	[redacted]	(278)	(283)	(116)	(156)	[redacted]	(5)
058 Personal Equipment	20	16	[redacted]	18	19	(2)	2	[redacted]	1
066 Other Goods & Services	109	176	[redacted]	105	109	(4)	(71)	[redacted]	4
190 Miscellaneous Revenue and Recoveries	*(211)*	*(159)*	[redacted]	*(166)*	*(169)*	*44*	*(7)*	[redacted]	*(3)*
Total Non-Labour	4,570	5,147	[redacted]	5,566	5,462	996	419	[redacted]	(104)
Total	***13,290***	***13,605***	[redacted]	***14,431***	***14,550***	***1,141***	***826***	[redacted]	***119***

Responsibility Area Technical & Construction Services	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	14,431	14,550	13,290	13,605	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Technical & Construction Services costs include Generation Planning & Services, Project Implementation, T&D Engineering & Planning & Performance, Environmental Services & Policy and the Protection Equipment Test Centre.		119	1,141	826	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalation.		223			
> **Employee Benefits** decrease due to decreased pension costs		(139)			
> **Other variations**		35			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to labour escalation partially offset by increase in FTEs charged to capital			144		
> **Employee Benefits** increase due to increased pension costs			1,049		
> **Corporate Support Transfer** increase allocation to affiliates			(116)		
> **Other variations**			64		

Responsibility Area Technical & Construction Services	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	14,431	14,550	13,290	13,605	[redacted]
Overview Technical & Construction Services costs include Generation Planning & Services, Project Implementation, T&D Engineering & Planning & Performance, Environmental Services & Policy and the Protection Equipment Test Centre.		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
		119	1,141	826	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalation partially offset by increase in FTEs charged to capital				407	
> **Travel** increase due to more travel relating to operating activities				106	
> **Contracts** decrease due to multi-year Canadian Clean Power Coalition (CCPC) commitment ends in 2012.				(114)	
> **Consulting** decrease due to non-recurring consultant costs for transition to Lower Water Street in 2011.				(177)	
> **Membership Dues** decrease due to Centre for Energy Advancement through Technological Innovation (CEATI) reimbursement in 2013.				(74)	
> **Rental/Maintenance equipment/software** increase due to additional planning software.				60	
> **Ext. Legal & Audit** decrease due to Biomass legal expenses in 2011				(492)	
> **Employee Benefits** increase due to increased pension costs				1,024	
> **Corporate Support Transfer** increase allocation to affiliates				(156)	
> **Non-Regulatory Cost Recovery** increase due to no recovery forecasted in 2013				189	
> **Other Goods and Services** decrease due to one time relocation expenses in 2011				(71)	
> **Other variations**				124	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to escalations partially offset by increase in FTEs charged to capital					
> **Employee Benefits** increase due to increased pension costs					
> **Other variations**					

Sustainability

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	751	684	[redacted]	581	597	(170)	(103)	[redacted]	16
010 Office Supplies	14	6		6	6	(8)	-		-
011 Travel Expense	64	(10)		31	31	(33)	41		-
012 Materials	1	10		1	1	-	(9)		-
013 Contracts	-	770		-	-	-	(770)		-
015 Frt, Post & Delivery	-	1		1	1	1	-		-
021 Telephones	15	12		14	15	(1)	2		1
028 Consulting	783	55		410	417	(373)	355		7
029 Membership Dues	14	14		14	15	-	-		1
032 Subscrpt/Info.Software	9	-		2	2	(7)	2		-
034 Appl. Software	-	4		-	-	-	(4)		-
035 Comp.Hrdwr & Op.Sftwr	9	3		6	6	(3)	3		-
037 Ext. Legal & Audit	32	4		54	55	22	50		1
040 Advertising	-	-		103	104	103	103		1
041 Meals & Entertainment	18	11		5	5	(13)	(6)		-
042 Employee Benefits	215	200		244	235	29	44		(9)
052 Non Reg.Cost Recovery	-	(68)		-	-	-	68		-
056 Training & Development	7	6		5	5	(2)	(1)		-
061 Write-offs	-	1,444		-	-	-	(1,444)		-
066 Other Goods & Services	38	42		31	32	(7)	(11)		1
Total Non-Labour	1,219	2,504		927	930	(292)	(1,577)		3
Total	***1,970***	***3,188***		***1,508***	***1,527***	***(462)***	***(1,680)***		***19***

Responsibility Area Sustainability	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	1,508	1,527	1,970	3,188	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Sustainability consists of Renewable energy development, special projects and strategic planning		19	(462)	(1,680)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Other variations**		19			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** decrease due to an increase in the amount of labour being direct-charged to capital programs			(170)		
> **Consulting** decrease due to less activity			(373)		
> **Advertising** increase due to advertising for new initiatives			103		
> **Other variations**			(22)		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** decrease due to an increase in the amount of labour being direct-charged to capital programs				(103)	
> **Contracts** decrease due to reduced renewable development activity				(770)	
> **Consulting** increased due to increased business development activity with wind				355	
> **External Legal & Audit** increase due to legal costs associated with third party projects				50	
> **Advertising** increase due to advertising for new initiative				103	
> **Non Reg. Cost Recovery** increase due to projects undertaken in 2011 that were supported by the Sustainability division not recurring in 2012				68	
> **Write Offs** decrease due to one-time charges of wind development costs in 2011				(1,444)	
> **Other variations**				61	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Other variations**					

Power Production
Head Office

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	997	694	[redacted]	1,518	1,451	522	825	[redacted]	(67)
010 Office Supplies	8	5	[redacted]	6	6	(2)	1	[redacted]	-
011 Travel Expense	92	24	[redacted]	87	89	(5)	63	[redacted]	2
012 Materials	5	23	[redacted]	6	6	1	(17)	[redacted]	-
013 Contracts	17	862	[redacted]	118	120	101	(744)	[redacted]	2
015 Frt, Post & Delivery	1	-	[redacted]	1	1	-	1	[redacted]	-
021 Telephones	16	7	[redacted]	6	6	(10)	(1)	[redacted]	-
028 Consulting	225	542	[redacted]	794	807	569	252	[redacted]	13
029 Membership Dues	110	90	[redacted]	95	97	(15)	5	[redacted]	2
032 Subscrpt/Info.Software	179	141	[redacted]	160	163	(19)	19	[redacted]	3
034 Appl. Software	-	1	[redacted]	-	-	-	(1)	[redacted]	-
037 Ext. Legal & Audit	2,036	453	[redacted]	1,784	1,813	(252)	1,331	[redacted]	29
041 Meals & Entertainment	14	30	[redacted]	16	17	2	(14)	[redacted]	1
042 Employee Benefits	13,631	12,983	[redacted]	20,031	19,257	6,400	7,048	[redacted]	(774)
056 Training & Development	5	-	[redacted]	41	42	36	41	[redacted]	1
066 Other Goods & Services	78	(9)	[redacted]	77	75	(1)	86	[redacted]	(2)
065 By-product Sales	*(503)*	*(782)*	[redacted]	-	-	*503*	*782*	[redacted]	-
Total Non-Labour	*15,914*	*14,370*	[redacted]	*23,222*	*22,499*	*7,308*	*8,852*	[redacted]	*(723)*
Total	***16,911***	***15,064***	[redacted]	***24,740***	***23,950***	***7,830***	***9,677***	[redacted]	***(790)***

Responsibility Area Power Production Head Office	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	24,740	23,950	16,911	15,064	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Head Office costs include Power Production Senior Management, Plant Operations and Management Information	(790)	7,829	9,676	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Labour** decrease due to a reduction in biomass project lead position, partially offset by labour escalation	(67)			
> **Employee Benefits** decrease due to decreased pension costs (Amount is for all of Power Production)	(774)			
> **Other Variations**	51			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** increase due to labour escalation and financial positions moved to Head Office cost centre		522		
> **Contracts** increase due to escalation and regulatory requirements		101		
> **Consulting** increase due to support of strategic asset planning		569		
> **Ext. Legal & Audit** decrease due to change in activity		(252)		
> **Employee Benefits** increase due to increased pension costs (Amount is for all of Power Production)		6,400		
> **By-product sales** decrease due to uncertainty in the market		503		
> **Other variations**		(14)		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** increase due to labour escalation and financial positions moved to Head Office cost centre.			825	
> **Travel** increase due to escalation and financial positions moved to Head Office cost centre.			63	
> **Contracts** decrease due to completion of a one time project			(744)	
> **Consulting** increase due to support of strategic asset planning			252	
> **Ext. Legal & Audit** increase due to change in activity			1,331	
> **Employee Benefits** increase due to increased pension costs (Amount is for all of Power Production)			7,048	
> **Other Goods & Services** increase due to reduction in uninsured loss in 2011			86	
> **By-product sales** decrease due to uncertainty in the market			782	
> **Other variations**			33	

Responsibility Area Power Production Head Office	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	24,740	23,950	16,911	15,064	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Head Office costs include Power Production Senior Management, Plant Operations and Management Information		(790)	7,829	9,676	[redacted]
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalation					
> **Consulting** decrease due to completion of a one time project					
> **Employee Benefits** increase due to increased pension costs (Amount is for all of Power Production)					
> **By-product sales** decrease due to uncertainty in the market					
> **Other variations**					

Thermal Plants

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	43,848	42,930	[redacted]	40,120	41,243	(3,728)	(2,810)	[redacted]	1,123
010 Office Supplies	83	86	[redacted]	79	80	(4)	(7)	[redacted]	1
011 Travel Expense	232	368	[redacted]	220	224	(12)	(148)	[redacted]	4
012 Materials	6,904	8,079	[redacted]	6,792	6,903	(112)	(1,287)	[redacted]	111
013 Contracts	11,456	15,597	[redacted]	10,850	11,028	(606)	(4,747)	[redacted]	178
014 Overtime Meals	114	123	[redacted]	105	106	(9)	(18)	[redacted]	1
015 Frt, Post & Delivery	105	152	[redacted]	119	121	14	(33)	[redacted]	2
016 Tools & Equipment	257	339	[redacted]	257	262	-	(82)	[redacted]	5
017 Chemicals	776	616	[redacted]	645	656	(131)	29	[redacted]	11
018 Gases	262	308	[redacted]	262	267	-	(46)	[redacted]	5
019 Water	1,006	822	[redacted]	976	992	(30)	154	[redacted]	16
021 Telephones	148	150	[redacted]	150	153	2	-	[redacted]	3
028 Consulting	86	1,811	[redacted]	250	254	164	(1,561)	[redacted]	4
029 Membership Dues	28	56	[redacted]	57	58	29	1	[redacted]	1
030 Lubricants	215	263	[redacted]	243	247	28	(20)	[redacted]	4
031 Fleet Fuel	48	56	[redacted]	51	54	3	(5)	[redacted]	3
033 Rental/Mtnce equipment/software	124	121	[redacted]	112	114	(12)	(9)	[redacted]	2
034 Appl. Software	24	21	[redacted]	25	25	1	4	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	11	7	[redacted]	14	14	3	7	[redacted]	-
037 Ext. Legal & Audit	-	123	[redacted]	-	-	-	(123)	[redacted]	-
041 Meals & Entertainment	141	288	[redacted]	152	155	11	(136)	[redacted]	3
050 Rent	42	41	[redacted]	42	43	-	1	[redacted]	1
055 Warranty & Service Contracts	6	4	[redacted]	6	6	-	2	[redacted]	-
056 Training & Development	179	213	[redacted]	243	247	64	30	[redacted]	4
058 Personal Equipment	233	297	[redacted]	215	219	(18)	(82)	[redacted]	4
061 Write-offs	-	113	[redacted]	-	-	-	(113)	[redacted]	-
066 Other Goods & Services	(2)	6	[redacted]	10	8	12	4	[redacted]	(2)
189 Steam Sales	-	*(197)*	[redacted]	-	-	-	*197*	[redacted]	-
Total Non-Labour	*22,478*	*29,863*	[redacted]	*21,875*	*22,236*	*(603)*	*(7,988)*	[redacted]	*361*
Total	***66,326***	***72,793***	[redacted]	***61,995***	***63,479***	***(4,331)***	***(10,798)***	[redacted]	***1,484***

Responsibility Area Power Production Thermal	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	61,995	63,479	66,326	72,793	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Thermal includes all costs related with the engineering, maintenance and operation of thermal generation stations including: Lingan, Point Aconi, Point Tupper, Tufts Cove and Trenton.	1,484	(4,331)	(10,798)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Labour** increase due to labour escalation	1,123			
> **Materials** increase due to escalation	111			
> **Contracts** increase due to escalation	178			
> **Other variations**	72			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** decrease due to seasonal operations at Lingan, other reduction in FTE, and continuous improvement savings, partially offset by labour escalation		(3,728)		
> **Materials** decrease due to two unit seasonal operations at Lingan, offset by escalation		(112)		
> **Contracts** decrease due to two unit seasonal operation at Lingan, offset by escalation		(606)		
> **Chemicals** decrease due to two unit seasonal operation at Lingan, offset by escalation		(131)		
> **Consulting** increase due to escalation and increased requirements to support operational projects across the fleet		164		
> **Training and Development** increase due to escalation and increased training requirements for new technology and new workforce requirements		64		
> **Other variations**		18		

Responsibility Area Power Production Thermal	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	61,995	63,479	66,326	72,793	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Thermal includes all costs related with the engineering, maintenance and operation of thermal generation stations including: Lingan, Point Aconi, Point Tupper, Tufts Cove and Trenton.		1,484	(4,331)	(10,798)	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** decrease due to seasonal operations at Lingan, TUC 6 project in 2011, continuous improvement savings, and financial positions moved to Head Office cost centre, offset by labour escalation				(2,810)	
> **Travel expense** decrease due to TUC 6 project in 2011 and financial positions moved to Head Office cost centre, offset by escalation				(148)	
> **Materials** decrease due to two unit seasonal operations at Lingan, TUC6 projects in 2011, offset by escalation				(1,287)	
> **Contracts** decrease due to two units seasonal operations at Lingan, TUC 6 project overrun in 2011, offset by escalation				(4,747)	
> **Tools & Equipment** decrease due to two unit seasonal operations at Lingan				(82)	
> **Water** increase due to escalation and TUC 6 operational				154	
> **Consulting** decrease due to 2011 TUC 6 project costs, offset by plant operation projects and escalation				(1,561)	
> **Ext. Legal & Audit** decrease due to less activity				(123)	
> **Meals and Entertainment** decrease due to seasonal operation of Lingan, a reduced spending forecast, offset by escalation				(136)	
> **Personal Equipment** decrease due to seasonal operation of Lingan, reduced spending forecast, offset by escalation				(82)	
> **Write-offs** decrease due to a one time adjustment in 2011				(113)	
> **Steam sales** decrease due to uncertainty in the market				197	
> **Other variations**				(60)	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** decrease due to two unit seasonal operation of Lingan and continuous improvement savings, offset by escalation					
> **Materials** decrease due to two unit seasonal operation at Lingan, offset by escalation					
> **Contracts** decrease due to two unit seasonal operation at Lingan, offset by escalation					
> **Other variations**					

Combustion Turbines

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	786	734	[redacted]	659	677	(127)	(75)	[redacted]	18
010 Office Supplies	3	3	[redacted]	4	4	1	1	[redacted]	-
011 Travel Expense	23	48	[redacted]	52	53	29	4	[redacted]	1
012 Materials	140	125	[redacted]	150	152	10	25	[redacted]	2
013 Contracts	291	364	[redacted]	313	318	22	(51)	[redacted]	5
014 Overtime Meals	3	1	[redacted]	2	3	(1)	1	[redacted]	1
015 Frt, Post & Delivery	7	10	[redacted]	8	8	1	(2)	[redacted]	-
016 Tools & Equipment	4	8	[redacted]	9	9	5	1	[redacted]	-
019 Water	1	1	[redacted]	1	1	-	-	[redacted]	-
021 Telephones	7	13	[redacted]	14	14	7	1	[redacted]	-
030 Lubricants	33	44	[redacted]	24	24	(9)	(20)	[redacted]	-
033 Rental/Mtnce equipment/software	4	12	[redacted]	5	5	1	(7)	[redacted]	-
034 Appl. Software	-	-	[redacted]	2	2	2	2	[redacted]	-
041 Meals & Entertainment	6	13	[redacted]	12	13	6	(1)	[redacted]	1
056 Training & Development	5	6	[redacted]	16	16	11	10	[redacted]	-
058 Personal Equipment	4	2	[redacted]	3	3	(1)	1	[redacted]	-
059 HR Costs	-	-	[redacted]	-	-	-	-	[redacted]	-
060 Commissions	-	-	[redacted]	-	-	-	-	[redacted]	-
061 Write-offs	-	-	[redacted]	-	-	-	-	[redacted]	-
062 Recoveries	-	-	[redacted]	-	-	-	-	[redacted]	-
064 Customer Recovery	-	-	[redacted]	-	-	-	-	[redacted]	-
066 Other Goods & Services	(1)	-	[redacted]	(2)	(1)	(1)	(2)	[redacted]	1
Total Non Labour	530	650	[redacted]	613	624	83	(37)	[redacted]	11
Total	***1,316***	***1,384***	[redacted]	***1,272***	***1,301***	***(44)***	***(112)***	[redacted]	***29***

Responsibility Area Power Production Combustion Turbines	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	1,272	1,301	1,316	1,384	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Combustion Turbines includes all costs related with the engineering, maintenance and operation of the combustion turbines.	29	(44)	(112)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Other variances**	29			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** decrease due to restructuring of plant financial staff and shared staff partially offset by labour escalation		(127)		
> **Other variances**		83		
2013 Forecast vs. 2011 Actuals (Thousands of $)				
> **Labour** decrease due to restructuring of plant financial group, overtime reduction, partially offset by labour escalation			(75)	
> **Contracts** decrease due to increased activity in 2011			(51)	
> **Other variances**			14	
2013 Forecast vs. 2012 Forecast (Thousands of $)				[redacted]
> **Contracts** increase due to timing of contracted maintenance work in 2011, 2012 and 2013				
> **Other variances**				

Wind and Hydro Energy

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	6,564	5,883	[redacted]	6,123	6,296	(441)	240	[redacted]	173
010 Office Supplies	21	21	[redacted]	20	20	(1)	(1)	[redacted]	-
011 Travel Expense	146	283	[redacted]	188	191	42	(95)	[redacted]	3
012 Materials	667	679	[redacted]	605	615	(62)	(74)	[redacted]	10
013 Contracts	4,266	3,629	[redacted]	5,048	5,131	782	1,419	[redacted]	83
014 Overtime Meals	8	9	[redacted]	10	10	2	1	[redacted]	-
015 Frt, Post & Delivery	5	12	[redacted]	4	4	(1)	(8)	[redacted]	-
016 Tools & Equipment	37	69	[redacted]	38	39	1	(31)	[redacted]	1
020 Royalties/Easements/Appraisals	-	142	[redacted]	-	-	-	(142)	[redacted]	-
021 Telephones	108	108	[redacted]	98	99	(10)	(10)	[redacted]	1
028 Consulting	482	459	[redacted]	599	609	117	140	[redacted]	10
029 Membership Dues	17	25	[redacted]	26	26	9	1	[redacted]	-
030 Lubricants	16	(2)	[redacted]	14	14	(2)	16	[redacted]	-
031 Fleet Fuel	209	251	[redacted]	217	230	8	(34)	[redacted]	13
033 Rental/Mtnce equipment/software	45	15	[redacted]	22	22	(23)	7	[redacted]	-
034 Appl. Software	-	-	[redacted]	3	3	3	3	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	-	3	[redacted]	-	-	-	(3)	[redacted]	-
041 Meals & Entertainment	76	89	[redacted]	77	78	1	(12)	[redacted]	1
043 Insurance	123	-	[redacted]	-	-	(123)	-	[redacted]	-
050 Rent	1,040	556	[redacted]	616	626	(424)	60	[redacted]	10
056 Training & Development	40	16	[redacted]	26	26	(14)	10	[redacted]	-
058 Personal Equipment	47	43	[redacted]	47	48	-	4	[redacted]	1
061 Write-offs	-	59	[redacted]	-	-	-	(59)	[redacted]	-
066 Other Goods & Services	32	36	[redacted]	34	36	2	(2)	[redacted]	2
091 Tax Assessment	861	300	[redacted]	575	584	(286)	275	[redacted]	9
Total Non-Labour	8,246	6,802	[redacted]	8,267	8,411	21	1,465	[redacted]	144
Total	***14,810***	***12,685***	[redacted]	***14,390***	***14,707***	***(420)***	***1,705***	[redacted]	***317***

Responsibility Area Power Production Wind and Hydro Energy	2013 Forecast 14,390	2014 Forecast 14,707	2012 Compliance 14,810	2011 Actual 12,685	2012 Forecast [redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Wind Energy includes all costs related to the engineering, maintenance and operation of wind turbine generation stations. Hydro includes all costs related with the engineering, maintenance and operation of hydro generation stations.		317	(420)	1,705	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalation		173			
> **Contracts** increase due to cost escalations		83			
> **Other variances**		61			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** decrease due to restructuring, partially offset by labour escalation			(441)		
> **Materials** decrease due to adjustment of base year estimates			(62)		
> **Contracts** increase due to escalation, a step change in contracts and insurance included within contract			782		
> **Consulting** increase due to escalation, dam safety and vegetation management program			117		
> **Insurance** decrease due to costs covered within contracts			(123)		
> **Rent** decrease due to change in lease forecast			(424)		
> **Tax Assessment** decrease due to forecast less than original estimate			(286)		
> **Other variances**			17		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalation, decrease in FTEs charged to capital, partially offset from continuous improvement savings, and financial position moved to Head office cost centre				240	
> **Travel expense** decrease due to reduced activity				(95)	
> **Materials** decrease due to one time spending in 2011				(74)	
> **Contracts** increase due to escalation, generation adjustments, and step change in contract				1,419	
> **Royalties/Easements/Appraisals** decrease due to one time adjustment for water royalties in 2011				(142)	
> **Consulting** increase due to escalation, vegetation management and dam safety program				140	
> **Rent** increase due to escalation				60	
> **Tax Assessment** increase due to adjustment to reflect generation and base year savings				275	
> **Write-offs** decrease due to one time adjustment in 2011				(59)	
> **Other variances**				(59)	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** decrease due to restructuring, partially offset by escalation					
> **Materials** increase due to escalation and maintenance profile					
> **Contracts** increase due to escalation					
> **Insurance** decrease due to costs covered within contract agreement					
> **Rent** decrease due to change in lease forecast					
> **Other variances**					

Biomass

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	-	-	[redacted]	3,307	3,468	3,307	3,307	[redacted]	161
010 Office Supplies	-	-	[redacted]	2	3	2	2	[redacted]	1
011 Travel Expense	-	-	[redacted]	31	41	31	31	[redacted]	10
012 Materials	-	-	[redacted]	514	693	514	514	[redacted]	179
013 Contracts	-	-	[redacted]	1,143	1,539	1,143	1,143	[redacted]	396
014 Overtime Meals	-	-	[redacted]	2	3	2	2	[redacted]	1
015 Frt, Post & Delivery	-	-	[redacted]	5	6	5	5	[redacted]	1
016 Tools & Equipment	-	-	[redacted]	19	26	19	19	[redacted]	7
017 Chemicals	-	-	[redacted]	77	104	77	77	[redacted]	27
018 Gases	-	-	[redacted]	15	21	15	15	[redacted]	6
019 Water	-	-	[redacted]	192	259	192	192	[redacted]	67
021 Telephones	-	-	[redacted]	9	12	9	9	[redacted]	3
029 Membership Dues	-	-	[redacted]	3	4	3	3	[redacted]	1
030 Lubricants	-	-	[redacted]	3	4	3	3	[redacted]	1
031 Fleet Fuel	-	-	[redacted]	6	8	6	6	[redacted]	2
033 Rental/Mtnce equipment/software	-	-	[redacted]	2	3	2	2	[redacted]	1
034 Appl. Software	-	-	[redacted]	3	4	3	3	[redacted]	1
035 Comp.Hrdwr & Op.Sftwr	-	-	[redacted]	3	4	3	3	[redacted]	1
041 Meals & Entertainment	-	-	[redacted]	6	8	6	6	[redacted]	2
056 Training & Development	-	-	[redacted]	15	21	15	15	[redacted]	6
058 Personal Equipment	-	-	[redacted]	21	28	21	21	[redacted]	7
066 Other Goods & Services	-	-	[redacted]	2	2	2	2	[redacted]	-
Total Non-Labour	-	-	[redacted]	2,073	2,793	2,073	2,073	[redacted]	720
Total	***-***	***-***	[redacted]	***5,380***	***6,261***	***5,380***	***5,380***	[redacted]	***881***

Responsibility Area Power Production Biomass	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	5,380	6,261	-	-	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Biomass includes all costs related to the Biomass operation in Port Hawkesbury		881	5,380	5,380	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase is reflective of full year of operation of Biomass facility		161			
> **Materials** increase is reflective of full year of operation of Biomass facility		179			
> **Contracts** increase is reflective of full year of operation of Biomass facility		396			
> **Water** increase is reflective of full year of operation of Biomass facility		67			
> **Other variances** is reflective of full year of operation of Biomass facility		78			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> First year of operation of Biomass facility			5,380		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> First year of operation of Biomass facility				5,380	
2013 Forecast vs. 2012 Forecast (Thousands of $)					
> First year of operation of Biomass facility					[redacted]

Energy, Fuels and Risk Management

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	2,540	2,349	[redacted]	2,349	2,414	(191)	-	[redacted]	65
010 Office Supplies	8	7	[redacted]	8	8	-	1	[redacted]	-
011 Travel Expense	109	68	[redacted]	103	104	(6)	35	[redacted]	1
012 Materials	4	7	[redacted]	4	4	-	(3)	[redacted]	-
013 Contracts	155	120	[redacted]	215	219	60	95	[redacted]	4
021 Telephones	58	28	[redacted]	34	34	(24)	6	[redacted]	-
028 Consulting	281	280	[redacted]	514	522	233	234	[redacted]	8
029 Membership Dues	7	6	[redacted]	7	8	-	1	[redacted]	1
032 Subscrpt/Info.Software	331	372	[redacted]	332	338	1	(40)	[redacted]	6
033 Rental/Mtnce equipment/software	77	4	[redacted]	103	104	26	99	[redacted]	1
034 Appl. Software	-	16	[redacted]	-	-	-	(16)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	-	4	[redacted]	-	-	-	(4)	[redacted]	-
037 Ext. Legal & Audit	123	1	[redacted]	62	63	(61)	61	[redacted]	1
041 Meals & Entertainment	40	13	[redacted]	15	16	(25)	2	[redacted]	1
052 Non Reg.Cost Recovery	-	(1)	[redacted]	-	-	-	1	[redacted]	-
056 Training & Development	61	31	[redacted]	52	52	(9)	21	[redacted]	-
066 Other Goods & Services	22	23	[redacted]	21	23	(1)	(2)	[redacted]	2
Total Non-Labour	1,276	979	[redacted]	1,470	1,495	194	491	[redacted]	25
Total	***3,816***	***3,328***	[redacted]	***3,819***	***3,909***	***3***	***491***	[redacted]	***90***

Responsibility Area Power Production Energy, Fuels and Risk Management	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	3,819	3,909	3,816	3,328	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Energy, Fuels and Risk Management includes the resources responsible for fuel procurement, marketing, management and generation dispatch.		90	3	491	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		65			
> **Other variances**		25			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** decrease due to reduction in FTEs, partially offset by labour escalation			(191)		
> **Consulting** increase due to escalation and added expertise for Biomass			233		
> **Contracts** increase due to escalation and additional wind power forecasting			60		
> **External Legal and Audit** decrease due to change in requirement			(61)		
> **Other variances**			(38)		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Contracts** increase due to escalation and additional wind power forecasting				95	
> **Consulting** increase due to added expertise for Biomass				234	
> **Rental/Maintenance equipment/software** increase due to escalation and change in 2011 coding of expense				99	
> **Ext. Legal & Audit** increase due to change in requirement				61	
> **Other variances**				2	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Consulting** increase due to escalation and added expertise for Biomass					
> **Other variances**					

Control Center

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	5,990	5,721	[redacted]	5,829	5,992	(161)	108	[redacted]	163
010 Office Supplies	9	11		9	10	-	(2)		1
011 Travel Expense	89	73		92	93	3	19		1
012 Materials	46	39		52	53	6	13		1
013 Contracts	365	399		368	374	3	(31)		6
014 Overtime Meals	3	2		3	3	-	1		-
015 Frt, Post & Delivery	5	5		5	5	-	-		-
016 Tools & Equipment	2	3		2	2	-	(1)		-
020 Royalties/Easements/Appraisals	47	52		48	49	1	(4)		1
021 Telephones	91	54		56	57	(35)	2		1
023 Data Communication Circuits	410	343		421	428	11	78		7
029 Membership Dues	378	363		380	386	2	17		6
032 Subscrpt/Info.Software	1	1		6	6	5	5		-
033 Rental/Mtnce equipment/software	108	132		157	159	49	25		2
034 Appl. Software	2	1		2	2	-	1		-
035 Comp.Hrdwr & Op.Sftwr	2	-		2	2	-	2		-
040 Advertising	4	-		4	4	-	4		-
041 Meals & Entertainment	39	35		39	40	-	4		1
050 Rent	125	91		125	127	-	34		2
052 Non Reg.Cost Recovery	-	(11)		-	-	-	11		-
055 Warranty & Service Contracts	336	228		389	395	53	161		6
056 Training & Development	73	78		75	77	2	(3)		2
058 Personal Equipment	16	15		10	10	(6)	(5)		-
066 Other Goods & Services	8	9		13	12	5	4		(1)
190 Miscellaneous Revenue and Recoveries	(87)	(326)		(91)	(92)	(4)	235		(1)
Total Non Labour	*2,072*	*1,597*		*2,167*	*2,202*	*95*	*570*		*35*
Total	***8,062***	***7,318***		***7,996***	***8,194***	***(66)***	***678***		***198***

Responsibility Area Customer Operations Control Center	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	7,996	8,194	8,062	7,318	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
The Control Center includes engineering, operations and management resources for the Energy Control Center (ECC) that controls the generation and transmission of power throughout the provincial grid.		198	(66)	678	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		163			
> **Other variances**		35			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** decrease due to anticipated efficiency gains offset by labour escalations			(161)		
> **Warranty & Service Contracts** increase due to increased SCADA software/hardware, NERC training software and cost escalations			53		
> **Other variances**			42		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalations				108	
> **Data Communication Circuits** increase due to the increase in SCADA pole-top recloser across the province				78	
> **Warranty & Service Contracts** increase due to increase in SCADA software/hardware, NERC training software and cost escalations				161	
> **Miscellaneous Revenue and Recoveries** decrease due to less activity				235	
> **Other variances**				96	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalation					
> **Other variances**					

Customer Operations - Administration (including Storm)

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	3,433	4,251	[redacted]	6,736	6,925	3,303	2,485	[redacted]	189
010 Office Supplies	6	-	[redacted]	6	6	-	6	[redacted]	-
011 Travel Expense	235	155	[redacted]	484	492	249	329	[redacted]	8
012 Materials	37	65	[redacted]	96	98	59	31	[redacted]	2
013 Contracts	1,907	2,360	[redacted]	3,467	3,524	1,560	1,107	[redacted]	57
014 Overtime Meals	41	67	[redacted]	129	131	88	62	[redacted]	2
015 Frt, Post & Delivery	1	2	[redacted]	1	1	-	(1)	[redacted]	-
021 Telephones	43	33	[redacted]	110	111	67	77	[redacted]	1
028 Consulting	228	(46)	[redacted]	234	237	6	280	[redacted]	3
029 Membership Dues	1	1	[redacted]	1	1	-	-	[redacted]	-
031 Fleet Fuel	2,638	2,994	[redacted]	2,705	2,871	67	(289)	[redacted]	166
034 Appl. Software	-	2	[redacted]	-	-	-	(2)	[redacted]	-
041 Meals & Entertainment	135	250	[redacted]	276	281	141	26	[redacted]	5
042 Employee Benefits	8,910	8,933	[redacted]	12,255	11,808	3,345	3,322	[redacted]	(447)
056 Training & Development	2	-	[redacted]	2	2	-	2	[redacted]	-
058 Personal Equipment	11	-	[redacted]	25	26	14	25	[redacted]	1
059 HR Costs	-	135	[redacted]	-	-	-	(135)	[redacted]	-
066 Other Goods & Services	12	1	[redacted]	14	14	2	13	[redacted]	-
190 Miscellaneous Revenue and Recoveries	(204)	(380)	[redacted]	(210)	(213)	(6)	170	[redacted]	(3)
Total Non-Labour	*14,003*	*14,572*	[redacted]	*19,595*	*19,390*	*5,592*	*5,023*	[redacted]	*(205)*
Total	***17,436***	***18,823***	[redacted]	***26,331***	***26,315***	***8,895***	***7,508***	[redacted]	***(16)***

Responsibility Area Customer Operations Administration & Storm	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	26,331	26,315	17,436	18,823	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Customer Operations Administration includes the costs associated with the senior management of the customer operations business unit. For tracking and control purposes, storm costs for the entire province are recorded in Customer Operations.		(16)	8,895	7,508	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		189			
> **Contracts** increase due to inflationary increases		57			
> **Fleet Fuel** increase due to estimated increase in fuel prices		166			
> **Employee Benefits** decrease due to decreased pension costs		(447)			
> **Other variances**		19			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to increased storm costs and escalation			3,303		
> **Travel expense** increase due to storm costs and escalation			249		
> **Materials** increase due to storm costs			59		
> **Contracts** increase due to storm costs and escalation			1,560		
> **Overtime meals** increase due to storm increase			88		
> **Telephones** increase due to storm increase			67		
> **Fleet Fuel** increase due to estimated increase in fuel prices			67		
> **Meals & Entertainment** increase due to storm increase			141		
> **Employee Benefits** increase due to increased pension costs			3,345		
> **Other variances**			16		

Responsibility Area Customer Operations Administration & Storm	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	26,331	26,315	17,436	18,823	[redacted]
Overview Customer Operations Administration includes the costs associated with the senior management of the customer operations business unit. For tracking and control purposes, storm costs for the entire province are recorded in Customer Operations.		**2014 Forecast vs. 2013 Forecast** (16)	**2013 Forecast vs. 2012 Compliance** 8,895	**2013 Forecast vs. 2011 Actual** 7,508	**2013 Forecast vs. 2012 Forecast** [redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to storm increase offset by transfer of labour to Resource Management Centre				2,485	
> **Travel expense** increase due to increased storm costs				329	
> **Contracts** increase due to increased storm costs				1,107	
> **Overtime meals** increase due to increased storm costs				62	
> **Telephones** increase due to increased storm costs				77	
> **Consulting** increase due to credit in 2011 that will not reoccur, combined with increased amount for consulting on process				280	
> **Fleet fuel** decrease due to anticipated efficiencies in fleet dispatch.				(289)	
> **Employee Benefits** increase due to increased pension costs				3,322	
> **Human Resource Costs** decrease due to one time cost in 2011 not repeated in 2013				(135)	
> **Miscellaneous Revenue and Recoveries** decrease due to storm relief revenues (monies earned supporting other utilities in storm restoration) earned in 2011 that are not forecasted to reoccur				170	
> **Other variances**				100	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due storm costs and labour escalations					
> **Travel expense** increase due to storm costs and escalation					
> **Contracts** increase due to storm costs and escalation					
> **Fleet Fuel** increase due to estimated increase in fuel prices.					
> **Meals & Entertainment** increase due to increased storm costs					
> **Employee Benefits** increase due to increased pension costs					
> **Other variances**					

Transmission Operations and Reliability

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	5,719	6,540	[redacted]	5,742	5,903	23	(798)	[redacted]	161
010 Office Supplies	19	15	[redacted]	15	15	(4)	-	[redacted]	-
011 Travel Expense	141	108	[redacted]	108	110	(33)	-	[redacted]	2
012 Materials	588	604	[redacted]	669	680	81	65	[redacted]	11
013 Contracts	8,970	9,762	[redacted]	14,295	14,529	5,325	4,533	[redacted]	234
014 Overtime Meals	19	26	[redacted]	21	21	2	(5)	[redacted]	-
015 Frt, Post & Delivery	8	12	[redacted]	11	11	3	(1)	[redacted]	-
016 Tools & Equipment	22	46	[redacted]	39	39	17	(7)	[redacted]	-
019 Water	-	-	[redacted]	-	-	-	-	[redacted]	-
020 Royalties/Easements/Appraisals	28	27	[redacted]	28	28	-	1	[redacted]	-
021 Telephones	111	116	[redacted]	115	116	4	(1)	[redacted]	1
025 Leasing	3	3	[redacted]	1	1	(2)	(2)	[redacted]	-
028 Consulting	1	-	[redacted]	-	-	(1)	-	[redacted]	-
029 Membership Dues	2	14	[redacted]	8	8	6	(6)	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	1	1	[redacted]	1	1	-	-	[redacted]	-
041 Meals & Entertainment	64	80	[redacted]	72	74	8	(8)	[redacted]	2
042 Employee Benefits	-	(1)	[redacted]	-	-	-	1	[redacted]	-
050 Rent	1	1	[redacted]	1	1	-	-	[redacted]	-
056 Training & Development	29	8	[redacted]	27	27	(2)	19	[redacted]	-
058 Personal Equipment	85	79	[redacted]	71	72	(14)	(8)	[redacted]	1
066 Other Goods & Services	20	42	[redacted]	39	43	19	(3)	[redacted]	4
190 Miscellaneous Revenue and Recoveries	(1,571)	(1,668)	[redacted]	(1,573)	(1,599)	(2)	95	[redacted]	(26)
Total Non-Labour	*8,541*	*9,275*	[redacted]	*13,948*	*14,177*	*5,407*	*4,673*	[redacted]	*229*
Total	***14,260***	***15,815***	[redacted]	***19,690***	***20,080***	***5,430***	***3,875***	[redacted]	***390***

Responsibility Area Customer Operations Transmission Operations and Reliability	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	19,690	20,080	14,260	15,815	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Reliability and Transmission provides centralized services for Customer Operations including: fleet management, forestry, and materials management.		390	5,430	3,875	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		161			
> **Contracts** increase due to cost escalations		234			
> **Other Variances**		(5)			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Materials** increase due to cost escalations			81		
> **Contracts** increase due to increased vegetation management program, movement of vegetation management costs previously reported in other areas, and cost escalation increases.			5,325		
> **Other variances**			24		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** decrease due to a reduction in workforce, partially offset by labour escalations				(798)	
> **Materials** increase due to cost escalations				65	
> **Contracts** increase due to enhanced reliability program in vegetation management for 2013 and beyond				4,533	
> **Miscellaneous Revenue and Recoveries** decrease due to a reduction in customer-contributed work				95	
> **Other variances**				(20)	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalations					
> **Contracts** increase due to increased vegetation management spend					
> **Other variances**					

Work Management and Resources

(in Thousands of $)

	2012 Compliance	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast	2013 Fct. Vs. 2012 Compliance	2013 Fct. Vs. 2011 Act.	2013 Fct. Vs. 2012 Fct.	2014 Fct. Vs. 2013 Fct.
Total Labour	4,002	3,831	[redacted]	4,347	4,469	345	516	[redacted]	122
010 Office Supplies	6	8	[redacted]	9	9	3	1	[redacted]	-
011 Travel Expense	12	18	[redacted]	21	21	9	3	[redacted]	-
012 Materials	467	658	[redacted]	664	675	197	6	[redacted]	11
013 Contracts	1,078	1,195	[redacted]	1,123	1,141	45	(72)	[redacted]	18
014 Overtime Meals	1	2	[redacted]	1	1	-	(1)	[redacted]	-
015 Frt, Post & Delivery	-	1	[redacted]	1	1	1	-	[redacted]	-
016 Tools & Equipment	2	-	[redacted]	1	1	(1)	1	[redacted]	-
021 Telephones	21	60	[redacted]	114	116	93	54	[redacted]	2
033 Rental/Mtnce equipment/software	66	72	[redacted]	66	67	-	(6)	[redacted]	1
034 Appl. Software	-	-	[redacted]	3	3	3	3	[redacted]	-
041 Meals & Entertainment	13	16	[redacted]	27	27	14	11	[redacted]	-
056 Training & Development	7	5	[redacted]	13	14	6	8	[redacted]	1
058 Personal Equipment	5	-	[redacted]	2	2	(3)	2	[redacted]	-
066 Other Goods & Services	2	1	[redacted]	2	2	-	1	[redacted]	-
190 Miscellaneous Revenue and Recoveries	(3,277)	(3,407)	[redacted]	(3,702)	(3,763)	(425)	(295)	[redacted]	(61)
Total Non-Labour	*(1,597)*	*(1,371)*	[redacted]	*(1,655)*	*(1,683)*	*(58)*	*(284)*	[redacted]	*(28)*
Total	***2,405***	***2,460***	[redacted]	***2,692***	***2,786***	***287***	***232***	[redacted]	***94***

Responsibility Area Customer Operations Work Management and Resources	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	2,692	2,786	2,405	2,460	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Workforce Management provides integrated workforce planning		94	287	232	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		122			
> **Miscellaneous Revenue and Recoveries**increased recovery due to escalation		(61)			
> **Other variances**		33			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** increase due to the movement of costs from Field Operations and labour escalations, offset by increased efficiencies			345		
> **Materials** increase due to aligning materials costs with historical spending and cost escalations			197		
> **Telephones** increase due to aligning costs with historical spending			93		
> **Miscellaneous Revenue and Recoveries**increase due to an increase in rate being billed for third-party line work			(425)		
> **Other variances**			77		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalations, increased third party activity, transfer of costs from COPs Admin, partially offset by efficiency gains				516	
> **Contracts** decrease due to anticipated reduced use of contractors to perform third party line work				(72)	
> **Telephones** increase due to alignment of telephone expenses with historical spend				54	
> **Miscellaneous Revenue and Recoveries**increase due to an increase in rate being billed for third-party line work partially offset by a decrease in volumes				(295)	
> **Other variances**				29	
> **2013 Forecast vs. 2012 Forecast (Thousands of $)**					[redacted]
> **Labour** increase due to labour escalations and movement of costs from Field Operations and COPs Admin					
> **Telephones** increase due to alignment of phone costs with historical spending					
> **Miscellaneous Revenue and Recoveries**increase due to an increase in rate being billed for third-party line work, partially offset by a decrease in work volumes					
> **Other variances**					

Field Operations

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	16,639	18,374	[redacted]	15,680	16,119	(959)	(2,694)	[redacted]	439
010 Office Supplies	73	40	[redacted]	46	47	(27)	6	[redacted]	1
011 Travel Expense	255	169	[redacted]	237	241	(18)	68	[redacted]	4
012 Materials	920	871	[redacted]	866	880	(54)	(5)	[redacted]	14
013 Contracts	4,778	5,024	[redacted]	5,174	5,258	396	150	[redacted]	84
014 Overtime Meals	43	62	[redacted]	55	56	12	(7)	[redacted]	1
015 Frt, Post & Delivery	13	21	[redacted]	20	20	7	(1)	[redacted]	-
016 Tools & Equipment	249	360	[redacted]	266	270	17	(94)	[redacted]	4
019 Water	19	23	[redacted]	19	19	-	(4)	[redacted]	-
020 Royalties/Easements/Appraisals	54	89	[redacted]	39	39	(15)	(50)	[redacted]	-
021 Telephones	624	447	[redacted]	606	615	(18)	159	[redacted]	9
025 Leasing	37	40	[redacted]	33	33	(4)	(7)	[redacted]	-
028 Consulting	61	72	[redacted]	63	64	2	(9)	[redacted]	1
029 Membership Dues	15	4	[redacted]	5	5	(10)	1	[redacted]	-
031 Fleet Fuel	1	2	[redacted]	-	-	(1)	(2)	[redacted]	-
033 Rental/Mtnce equipment/software	1	3	[redacted]	1	1	-	(2)	[redacted]	-
034 Appl. Software	5	1	[redacted]	2	2	(3)	1	[redacted]	-
035 Comp.Hrdwr & Op.Sftwr	5	2	[redacted]	3	3	(2)	1	[redacted]	-
040 Advertising	2	2	[redacted]	-	-	(2)	(2)	[redacted]	-
041 Meals & Entertainment	152	134	[redacted]	139	142	(13)	5	[redacted]	3
042 Employee Benefits	-	48	[redacted]	-	-	-	(48)	[redacted]	-
056 Training & Development	42	20	[redacted]	26	27	(16)	6	[redacted]	1
058 Personal Equipment	395	421	[redacted]	398	404	3	(23)	[redacted]	6
066 Other Goods & Services	(70)	(242)	[redacted]	(44)	(41)	26	198	[redacted]	3
190 Miscellaneous Revenue and Recoveries	(1,003)	(1,344)	[redacted]	(1,093)	(1,111)	(90)	251	[redacted]	(18)
Total Non-Labour	*6,671*	*6,269*	[redacted]	*6,862*	*6,975*	*190*	*592*	[redacted]	*113*
Total	***23,310***	***24,643***	[redacted]	***22,542***	***23,094***	***(769)***	***(2,102)***	[redacted]	***552***

Responsibility Area Customer Operations Field Operations	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	22,542	23,094	23,310	24,643	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Regional Operations includes all field related transmission and distribution services across the province.		552	(768)	(2,101)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)					
> **Labour** increase due to labour escalations		439			
> **Contracts** increase due to escalation		84			
> **Other variances**		29			
2013 Forecast vs. 2012 Compliance (Thousands of $)					
> **Labour** decrease due to anticipated efficiency gains, transfer to Work Management and Resource Allocation and succession planning, partially offset by labour escalations			(959)		
> **Materials** decrease due to movement of costs to Transmission Operations and Reliability, partially offset by escalation			(54)		
> **Contracts** increase due to escalation and an increase in contractor volumes in support of workforce adjustments			396		
> **Miscellaneous Revenue and Recoveries**increase due to an increase in the volume of miscellaneous customer work			(90)		
> **Other variances**			(61)		
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** decrease due to reduction in workforce, partially offset by labour escalations				(2,694)	
> **Contracts** increase due to escalation, offset by improvement in utilization				150	
> **Tools & Equipment** decrease due to anticipated reduction in tool usage				(94)	
> **Royalties/Easement/Appraisals** decrease due to anticipated reduction in requirements for items				(50)	
> **Telephones** increase due to anticipated increased mobile workforce demands				159	
> **Travel Expense** increase due to reallocation from other areas and cost escalations				68	
> **Other Goods and Services** increase due to shift in reporting for vehicle charges between cost centres				198	
> **Miscellaneous Revenue and Recoveries**decrease due to reduction in volume of miscellaneous customer work				251	
> **Other variances**				(89)	

Responsibility Area Customer Operations Field Operations		2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
		22,542	23,094	23,310	24,643	[redacted]
Overview			**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Regional Operations includes all field related transmission and distribution services across the province.			552	(768)	(2,101)	[redacted]
2013 Forecast vs. 2012 Forecast (Thousands of $)						[redacted]
>	**Labour** increase due to increased labour escalations and Long-Term disability costs moved from employee benefits line item, partially offset by move of resources to Resource Management Centre					
>	**Contracts** increase due to cost escalations					
>	**Employee Benefits** decrease due to movement of Long Term disability costs to labour accounts					
>	**Other variances**					

Customer Service, Marketing and Sales

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	17,462	17,687	[redacted]	17,814	18,313	352	127	[redacted]	499
010 Office Supplies	51	39		53	53	2	14		-
011 Travel Expense	177	199		182	185	5	(17)		3
012 Materials	496	462		508	517	12	46		9
013 Contracts	1,542	1,045		1,542	1,542	-	497		-
014 Overtime Meals	7	10		7	7	-	(3)		-
015 Frt, Post & Delivery	2,119	2,168		2,172	2,208	53	4		36
016 Tools & Equipment	2	1		2	3	-	1		1
021 Telephones	282	259		193	196	(89)	(66)		3
025 Leasing	29	45		31	31	2	(14)		-
028 Consulting	415	836		415	415	-	(421)		-
029 Membership Dues	98	94		101	103	3	7		2
031 Fleet Fuel	459	592		471	500	12	(121)		29
033 Rental/Mtnce equipment/software	818	1,201		1,028	1,028	210	(173)		-
034 Appl. Software	6	201		9	9	3	(192)		-
035 Comp.Hrdwr & Op.Sftwr	39	15		15	16	(24)	-		1
040 Advertising	513	294		526	535	13	232		9
041 Meals & Entertainment	108	136		111	113	3	(25)		2
042 Employee Benefits	4,087	4,484		6,184	5,958	2,097	1,700		(226)
055 Warranty & Service Contracts	10	-		10	10	-	10		-
056 Training & Development	76	499		108	110	32	(391)		2
058 Personal Equipment	48	120		77	78	29	(43)		1
060 Commissions	439	222		439	446	-	217		7
061 Write-offs	5,722	11,551		7,744	7,744	2,022	(3,807)		-
062 Recoveries	(2,336)	(1,634)		(2,336)	(2,374)	-	(702)		(38)
064 Customer Recovery	23	58		24	24	1	(34)		-
066 Other Goods & Services	3	10		15	14	12	5		(1)
083 Short-term interest	(157)	(157)		(161)	(163)	(4)	(4)		(2)
190 Miscellaneous Revenue and Recoveries	(134)	(505)		(258)	(263)	(124)	247		(5)
Total Non-Labour	*14,942*	*22,245*		*19,212*	*19,045*	*4,270*	*(3,033)*		*(167)*
Total	***32,404***	***39,932***		***37,026***	***37,358***	***4,622***	***(2,906)***		***332***

Responsibility Area Customer Service	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	37,026	37,358	32,404	39,932	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Customer Service includes the customer care centre, billing and payment services, meter services, credit and collections, customer communications, quality assurance, heating solutions, large customer management, load and revenue forecasting and energy utilization programs.	332	4,622	(2,906)	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Labour** increase due to labour escalation	499			
> **Employee Benefits** decrease due to decreased pension costs	(226)			
> **Other variances**	59			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** increase due to labour escalation, partially offset by changes in staffing levels		352		
> **Freight, Post & Delivery** increase due to cost escalations		53		
> **Telephone** decrease due to reallocation of costs to Rental/Maintenance equipment/software and efficiencies gained through process improvements		(89)		
> **Rental/Maintenance equipment/software**increase due reallocation of telephone costs and increased costs associated with customer service initiatives		210		
> **Employee Benefits** increase due to increased pension costs		2,097		
> **Write offs** increase due to expected increase in average write-off amount		2,022		
> **Miscellaneous Revenue and Recoveries**increased recovery due to cost escalations		(124)		
> **Other variances**		101		

Responsibility Area Customer Service	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
	37,026	37,358	32,404	39,932	[redacted]
Overview		**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Customer Service includes the customer care centre, billing and payment services, meter services, credit and collections, customer communications, quality assurance, heating solutions, large customer management, load and revenue forecasting and energy utilization programs.		332	4,622	(2,906)	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)					
> **Labour** increase due to labour escalations partially offset by changes in staffing levels				127	
> **Contracts** increase due to higher anticipated volume of storm outage calls routed through HVCA, and costs associated with additional home shows and off-site storage				497	
> **Telephone** decrease due to reallocation of costs to Rental/Maintenance equipment/software				(66)	
> **Consulting** decrease due to completion of a customer satisfaction improvement project and reallocation of effort to advertising				(421)	
> **Fleet Fuel** decrease due to anticipated efficiencies (new vehicles, less idling)				(121)	
> **Application Software** decrease due to the completion of a customer satisfaction improvement project				(192)	
> **Rental/Maintenance equipment/Software** decrease due to completion of a customer satisfaction improvement project partially offset by reallocated telephone costs				(173)	
> **Advertising** increase due to promoting ebills, co-operative promotion of ETS units and realigned consulting costs				232	
> **Employee Benefits** increase due to increased pension costs				1,700	
> **Training and Development** decrease due to the completion of a customer satisfaction improvement project				(391)	
> **Commission** increase due to improvements in collection processes				217	
> **Write-offs** decrease due to one time write-off provision made in December 2011 not forecasted in 2013				(3,807)	
> **Recoveries** increase due to forecasted cost efficiencies gained in the management of Net Bad Debt.				(702)	
> **Miscellaneous Revenue and Recoveries** decreased recovery due to decreased expenses associated with Efficiency Nova Scotia and decreased customer recoveries in Meter Services, partially offset by increased revenue related to wiring inspection seminars.				247	
> **Other variances**				(53)	
2013 Forecast vs. 2012 Forecast (Thousands of $)					[redacted]
> **Labour** increase due to labour escalations, partially offset by changes in staffing levels					
> **Freight, Post & Delivery** increase due to cost escalations					
> **Employee Benefits** increase due to increased pension costs					
> **Write-offs** increase due to expected increase in the average write-off amount					
> **Other variances**					

Corporate Adjustments

(in Thousands of $)

	2012 Compliance	*2011 Actual*	*2012 Forecast*	*2013 Forecast*	*2014 Forecast*	*2013 Fct. Vs. 2012 Compliance*	*2013 Fct. Vs. 2011 Act.*	*2013 Fct. Vs. 2012 Fct.*	*2014 Fct. Vs. 2013 Fct.*
Total Labour	2,997	4,515	[redacted]	3,585	3,926	588	(930)	[redacted]	341
036 Directors' Fees & Exp	-	92	[redacted]	-	-	-	(92)	[redacted]	-
042 Employee Benefits	-	(1,039)	[redacted]	-	-	-	1,039	[redacted]	-
059 HR Costs	-	137	[redacted]	1,693	1,693	1,693	1,556	[redacted]	-
061 Write-offs	613	1,122	[redacted]	820	834	207	(302)	[redacted]	14
066 Other Goods & Services	591	581	[redacted]	659	723	68	78	[redacted]	64
091 Tax Assessment	-	(1)	[redacted]	-	-	-	1	[redacted]	-
092 Vehicle Allocated Costs	(4,442)	(7,295)	[redacted]	(4,814)	(5,303)	(372)	2,481	[redacted]	(489)
095 Admin. Overheads	(21,991)	(24,324)	[redacted]	(23,216)	(23,819)	(1,225)	1,108	[redacted]	(603)
Total Non-Labour	(25,229)	(30,727)	[redacted]	(24,858)	(25,872)	371	5,869	[redacted]	(1,014)
057 Corp Support Transfer	(1,007)	(979)	[redacted]	(917)	(943)	90	62	[redacted]	(26)
083 Short Term Interest	(1,066)	(1,189)	[redacted]	(1,231)	(1,251)	(165)	(42)	[redacted]	(20)
Revenue Reclasses	6,347	8,807	[redacted]	6,526	6,633	179	(2,281)	[redacted]	107
Total	***(17,958)***	***(19,573)***	[redacted]	***(16,895)***	***(17,507)***	***1,063***	***2,678***	[redacted]	***(612)***

Responsibility Area Corporate Groups	2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
Total Corporate Adjustments	(16,895)	(17,507)	(17,958)	(19,573)	[redacted]

Overview	2014 Forecast vs. 2013 Forecast	2013 Forecast vs. 2012 Compliance	2013 Forecast vs. 2011 Actual	2013 Forecast vs. 2012 Forecast
Corporate Adjustments are expenses not assigned to a specific business unit or functional area. This includes payroll costs (including year-end payroll accrual and accrued incentives) and capital overhead contributions.	(612)	1,063	2,678	[redacted]
2014 Forecast vs. 2013 Forecast (Thousands of $)				
> **Labour** increase due to labour escalation	341			
> **Vehicle Allocated Costs** increased recovery due to increased capital spend	(489)			
> **Administrative Overheads** increased recovery due to increased capital spend	(603)			
> **Other Goods and Services** increase due to increased participation in Employee Share Purchase Plan	64			
> **Revenue Reclasses** increased revenues and recoveries in operating groups resulting in increased reclass to revenue	107			
> **Other Variations**	(32)			
2013 Forecast vs. 2012 Compliance (Thousands of $)				
> **Labour** increase due to labour escalation and timing of labour accurals		588		
> **Human Resource Costs** increased due to amortization of workforce reduction costs		1,693		
> **Write offs increase** due to increased inventory write offs		207		
> **Other Goods and Services** increase due to increased participation in Employee Share Purchase Plan		68		
> **Vehicle Allocated Costs** increased recovery due to profile of capital spend		(372)		
> **Administrative Overheads** increased recovery due to profile of capital spend		(1,225)		
> **Corp Support Transfer** decrease due to less costs being allocated to affiliates		90		
> **Short Term Interest** increased due to escalation		(165)		
> **Revenue Reclasses** increased revenues and recoveries in operating groups resulting in increased reclass to revenue		179		
> **Other Variations**		-		

Responsibility Area Corporate Groups		2013 Forecast	2014 Forecast	2012 Compliance	2011 Actual	2012 Forecast
Total Corporate Adjustments		(16,895)	(17,507)	(17,958)	(19,573)	[redacted]
Overview			**2014 Forecast vs. 2013 Forecast**	**2013 Forecast vs. 2012 Compliance**	**2013 Forecast vs. 2011 Actual**	**2013 Forecast vs. 2012 Forecast**
Corporate Adjustments are expenses not assigned to a specific business unit or functional area. This includes payroll costs (including year-end payroll accrual and accrued incentives) and capital overhead contributions.			(612)	1,063	2,678	[redacted]
2013 Forecast vs. 2011 Actuals (Thousands of $)						
>	**Labour** decrease due to timing of labour accurals and lower labour costs				(930)	
>	**Directors' Fees** decrease as a result of actual 2011 director fees				(92)	
>	**Employee Benefits** increase due to a resulting difference between actual pension expense and amount transferred to business units				1,039	
>	**Human Resources Costs** increased due to amortization of workforce reduction costs				1,556	
>	**Write-offs** decrease in inventory obsolescence reallocation from Procurement				(302)	
>	**Other Goods and Services** increase due to increased participation in Employee Share Purchase Plan				78	
>	**Vehicle Allocated Costs** decreased recovery due to reduced capital spend				2,481	
>	**Administrative Overheads** decreased recovery due to reduced capital spend				1,108	
>	**Corp Support Transfer** decrease due to less cost being allocated to affiliates resulting from less activity				62	
>	**Revenue Reclasses** decreased due to higher recoveries in 2011 not expected to continue				(2,281)	
>	**Other Variations**				(41)	
2013 Forecast vs. 2012 Forecast (Thousands of $)						[redacted]
>	**Labour** increase due to labour escalation					
>	**Human Resources Costs** increased due to workforce reduction costs					
>	**Other Goods and Services** increase due to increased participation in Employee Share Purchase Plan					
>	**Vehicle Allocated Costs** increased recovery due to profile of capital spend					
>	**Administrative Overheads** increased recovery due to profile of capital spend					
>	**Revenue Reclasses** decreased due to higher forecasted recoveries in 2012 not expected to continue					
>	**Other Variations**					

1 OPERATING COSTS BY GROUP

1.1 Power Production

Power Production includes the operation and maintenance of our generating plants and costs associated with fuel procurement, FAM administration and management.

Power Production accounts for about 40 percent of total operating costs forecast for 2013 and 2014, respectively. Figure 1-1 summarizes the annual operating expense for Power Production and the factors driving the variance are outlined in Figure 1-2.

Figure 1-1

Power Production ($M)				
2011A	**2012C**	[redacted]	**2013F**	**2014F**
105.3	103.2		111.6	113.6

Figure 1-2

Cost Amount ($M)	2013 vs. 2012C	2014 vs. 2013
Union and non-union labour	1.9	1.5
Other labour savings (not related to Lingan or Biomass)	(2.9)	(0.1)
Biomass project	5.4	0.7
Pension	6.5	(0.7)
Lingan Transformation	(4.1)	-
Other costs (net of savings)	1.6	0.6
Total	**8.4**	**2.0**

In 2013, costs for Power Production increase by $8.4 million over the 2012 GRA Compliance Filing (2012C), an increase of 8.1 percent and an additional $2 million in 2014, an increase of just under 2 percent over 2013.

Most of the increase in 2013, amounting to $6.5 million, is a result of an increase in pension costs over 2012C. Excluding pension costs, 2013 Power Production costs increased by 1.89 even with the addition of a new renewable energy plant.

In April 2013, the Biomass project in Port Hawkesbury will go into service, with added costs of $5.4 million. This amount is offset by a reduction in thermal costs of $4.1 million relating to two units at Lingan moving to a seasonal operation.

The operating environment of our generating fleet has changed due to the reduction in industrial load, the provincial Renewable Electricity Standards and emission limits. During 2012, the Lingan Generating station began seasonally operating two of the four units. These two units are expected to be needed only during the coldest winter months, December to March.

In 2014, the $1.5 million increase in wages is partially offset by a $0.7 million decrease in pension expense, with the Biomass project resulting in an additional increase of $0.7 million due to a full year of generation.

With the exception of pension, Power Production cost increases have been held to 1.89 percent per year, which is in line with inflation.

1.2 Customer Operations

Customer Operations includes: Regional Operations (transmission and distribution field operating groups), Transmission and Control Centre Operations (including the System Operator function), Reliability Programming (including vegetation management), Work Force Management and Resource Allocation (planning, scheduling and dispatch) and Administration.

Customer Operations accounts for about 28 percent of the total operating costs forecast for 2013 and 2014, respectively. Figure 1-3 summarizes the annual operating costs for Customer Operations and the factors driving the variance are outlined in Figure 1-4.

Figure 1-3

Customer Operations ($M)				
2011A	2012C	[redacted]	2013F	2014F
69.1	65.5		79.3	80.5

Figure 1-4

Cost Amount ($M)	2013 vs. 2012C	2013 vs. 2014
Union and non-union labour	(0.6)	1.1
Vegetation management investment	3.4	-
Storm response	5.5	-
Pension	3.4	(0.4)
Other costs (net of savings)	2.1	0.5
Total	**13.8**	**1.2**

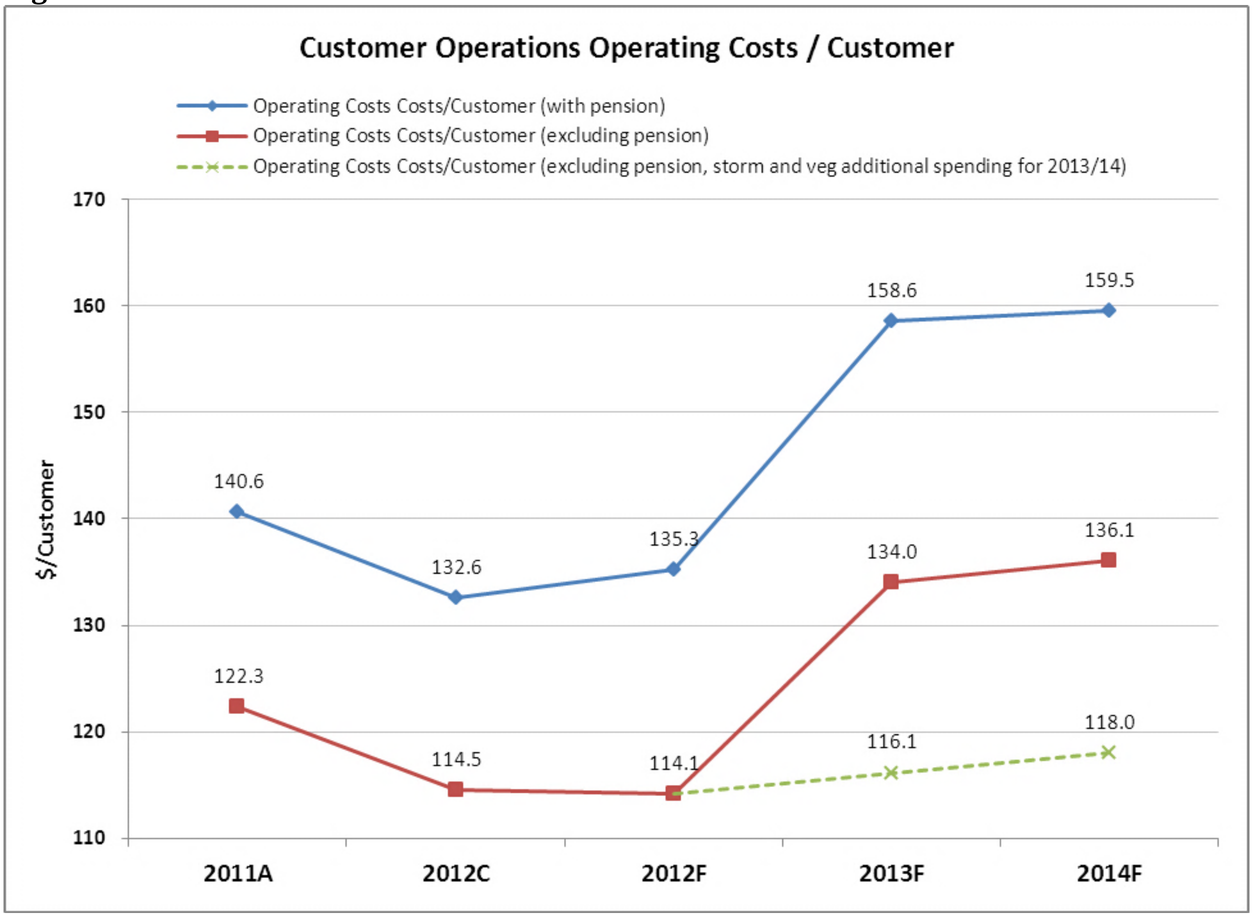
Costs for Customer Operations will increase by $13.8 million over 2012C, an increase of 21 percent. Increased investments in storm and vegetation management account for $8.9 million or 64 percent of the increase. Increased pension costs account for $3.4 million or 25 percent of the increase. Of the remaining $1.5 million of the increase, or approximately a 2 percent increase over 2012C, these costs are related escalations, and are in line with inflation.

The increases in vegetation management and storm costs relate directly to the increased frequency and severity of weather experienced in Nova Scotia, in particular high winds. The frequency of high winds results in higher storm response costs, and the requirement to increase vegetation management investment as discussed in Section 4.

In 2014, costs for Customer Operations will increase by $1.2 million, or 1.5 percent, over 2013, which is less than inflation.

Figure 1-5 below shows Customer Operations costs per customer from 2011 to 2014.

Figure 1-5



1.3 Customer Service

NS Power's Customer Service group includes the customer care centre, billing and payment services, meter services, credit and collections, customer communications and quality assurance, customer relations, heating solutions, large customer management and load and revenue forecasting.

The Customer Service group accounts for about 13 percent of the total operating costs forecast for 2013 and 2014 respectively. Figure 1-6 summarizes the annual operating costs for Customer Service and the factors driving the variance are outlined in Figure 1-7.

Figure 1-6

Customer Service ($M)				
2011A	**2012C**	[redacted]	**2013F**	**2014F**
39.9	32.4		37.0	37.4

Figure 1-7

Cost Amount ($M)	2013 vs 2012C	2013 vs 2014
Union and non-union labour	0.4	0.5
Pension	2.1	(0.2)
Electric revenue write-offs and allowances for bad debt	2.0	-
Other costs (net of savings)	0.1	0.1
Total	**4.6**	**0.4**

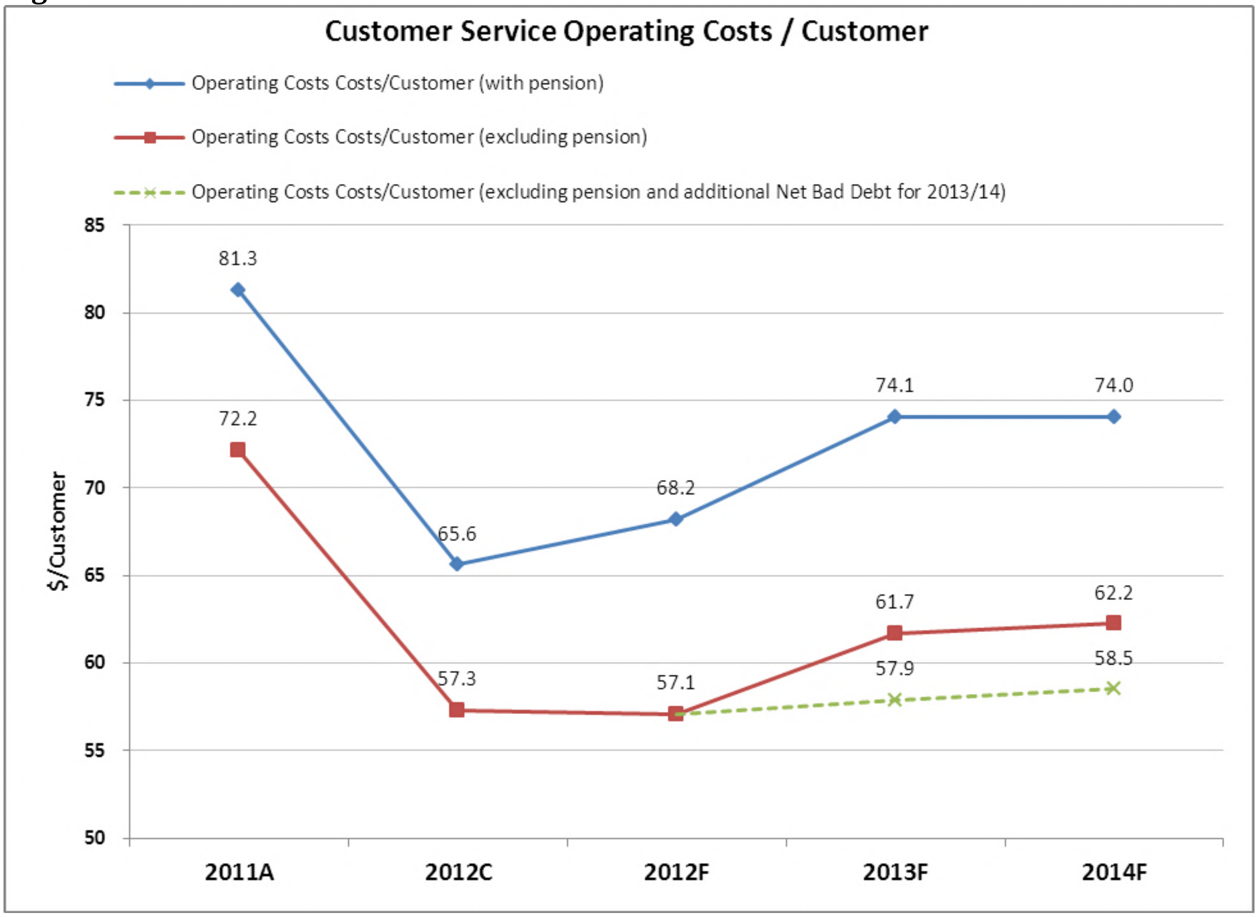
In 2013, costs for Customer Service will increase by $4.6 million, or 14 percent, over 2012C. Increase in electric revenue write-offs and allowances for bad debt to reflect actual write-off experience accounts for $2 million, or approximately 44 percent, of the increase as discussed in Section 4.

Increased pension costs account for $2.1 million of the increase. The remaining $0.5 million is a 1.5 percent increase over 2012C, which is lower than inflation.

In 2014, costs for Customer Services will increase by $0.4 million, or 1.1 percent, over 2013.

Figure 1-8 below shows Customer Service costs per customer from 2011 to 2014.

Figure 1-8



1.4 Technical and Construction Services

The Technical and Construction Services group focuses on investment planning and execution, initiatives to further enhance reliability, asset management and operational excellence, support for renewables, environmental compliance and transformation, and providing technical support to the Power Production and Customer Operations groups.

Technical and Construction Services accounts for about 5 percent of the total operating costs forecast for 2013 and 2014 respectively. Figure 1-9 summarizes the annual operating costs for Technical and Construction Services and the factors driving the variance are outlined in Figure 1-10.

Figure 1-9

Technical and Construction Services ($M)				
2011A	**2012C**	[redacted]	**2013F**	**2014F**
13.6	13.3	[redacted]	14.4	14.6

Figure 1-10

Cost Amount ($M)	2013 vs 2012C	2014 vs 2013
Union and non-union labour	0.3	0.2
Reductions in FTE's	(0.2)	-
Pension	1.0	(0.1)
Other costs (net of savings)	-	0.1
Total	**1.1**	**0.2**

NS Power's Technical and Construction Services group operating costs will increase by $1.1 million, or 8.3 percent, in 2013 as compared to 2012C, and by $0.2 million, or 1.4 percent, in 2014 as compared to 2013.

The increase in 2013 is a result of an increase in pension costs over 2012C. In 2014, the increase is due to wage escalation, which is partially offset by a reduction in pension expense.

1.5 Sustainability

The Sustainability group's primary responsibility is to lead the transformation of the currently carbon intensive generation side of the business to a much more balanced portfolio of prime energy sources.

The Sustainability group accounts for less than 1 percent of the total operating costs forecast for 2013 and 2014 respectively. Figure 1-11 summarizes the annual operating costs for Sustainability and the factors driving the variance are outlined in Figure 1-12.

Figure 1-11

Sustainability ($M)				
2011A	**2012C**	[redacted]	**2013F**	**2014F**
3.2	2.0	[redacted]	1.5	1.5

Figure 1-12

Cost Amount ($M)	2013 vs 2012C	2014 vs 2013
Non-union labour	(0.2)	-
Consulting	(0.4)	-
Other costs (net of savings)	0.1	-
Total	**(0.5)**	**-**

The decrease in 2013 is a result of lower activity levels as compared to 2012C.

1.6 Corporate Support Groups

NS Power's Corporate Support groups provide services such as Regulatory Affairs, Finance, Governance, Human Resource Management, Communications and Public Affairs, Procurement and Information Technology.

The Corporate Support groups work to control costs. Operational efficiencies, quality improvements, management of staffing levels, appropriate procurement sourcing and bid evaluation all assist with controlling costs across the Company.

NS Power continues to manage corporate costs as outlined in the Accenture report and subsequently accepted by the Board in a letter dated May 18, 2007:

> As noted above, the Board is prepared to accept the Accenture Report as an adequate review of Corporate Services, subject to Accenture providing the Board with a more extensive and detailed summary of the findings, recommendations and issues identified in its Report, as well as satisfactory responses to any further questions the Board may have.[1]

The Corporate Support group accounts for about 19 percent of the total operating costs forecast for 2013 and 2014 respectively. Figure 1-13 summarizes the annual operating costs for Corporate Support and the factors driving the variance are outlined in Figure 1-14.

[1] UARB Letter to NSPI, Nova Scotia Power Inc.–Operations Review–P-886.2, May 18, 2007, page 3.

Figure 1-13

Customer Operations ($M)				
2011A	**2012C**	[redacted]	**2013F**	**2014F**
49.9	47.3		52.1	53.1

Figure 1-14

Cost Amount ($M)	2013 vs. 2012C	2013 vs 2014
Non-union labour	0.7	0.6
Other labour increases (recovered through corporate support recoveries)	0.7	0.1
Pension	3.1	(0.3)
Insurance costs	0.7	0.3
Rental and Maintenance of equipment and software	0.5	0.3
Corporate Support Recoveries	(1.7)	(0.2)
Other	0.8	0.2
Total	**4.8**	**1.0**

Operating costs relating to NS Power's Corporate Support groups will increase by $4.8 million, or 10 percent, in 2013 as compared to 2012C, and increase by $1 million, or 1.9 percent, in 2014 as compared to 2013.

In 2013 increased pension expense accounts for $3.1 million, or approximately 65 percent, of the increase. The remaining $1.7 million is due to increased insurance and rental and maintenance costs. In 2014, increased insurance and rental and maintenance costs account for $0.6 million, or 60 percent, of the increase, with the remaining increase related to labour escalation.

Other labour increases are largely recovered by NS Power through Corporate Support recoveries, which demonstrate that the increase in FTEs was driven by growth in affiliates and are therefore charged to them.

Insurance cost increases are based on our most recent experience. The increases for rental and maintenance of equipment and software are related to new maintenance agreements associated with new software contracts and implementations.

1.7 Corporate Adjustments

Corporate Adjustments are credits and expenses that are not assigned to a specific business unit or functional area. The primary components are capital overhead contributions and certain payroll costs (including incentives and year-end payroll accruals).

Figure 1-15 summarizes the annual operating costs Corporate Adjustment and Figure 1-16 summarizes the components of Corporate Adjustments and Overheads.

Figure 1-15

Corporate Adjustments ($M)				
2011A	**2012C Restated**	[redacted]	**2013F**	**2014F**
(19.6)	(18.0)	[redacted]	(16.9)	(17.6)

Figure 1-16

Corporate Adjustments by Expense Type ($M)					
	2011A	**2012C Restated**	[redacted]	**2013F**	**2014F**
Labour related costs	4.5	3.0	[redacted]	3.6	3.9
Administrative Overheads	(31.6)	(26.4)	[redacted]	(28.0)	(29.1)
Corporate Support Transfers	(1.0)	(1.0)	[redacted]	(0.9)	(0.9)
Workforce Reduction Amortization	-	-	[redacted]	[redacted]	[redacted]
Revenue Reclass	8.8	6.3	[redacted]	6.5	6.6
Other	(0.3)	0.1	[redacted]	0.2	0.2
Total	**(19.6)**	**(18.0)**	[redacted]	**(16.9)**	**(17.6)**

2012C has been restated to reflect the reclassification of revenues previously included in operating costs to other revenues. In the past, NS Power has netted certain revenues against operating costs. The amounts of revenues netted in the operating group's costs are included on the revenue reclass line above. This adjustment in Corporate Adjustments increases operating costs by removing the revenues which were previously netted, and increases other revenues on the Income Statement.

In 2013, the Corporate Adjustment credit will decrease by $1.1 million over 2012C restated. This is mainly due to increased costs associated with workforce reduction amortization of [redacted] and increased labour related costs associated with timing of payroll accruals and labour escalations, which were partially offset by an increase in administrative overheads of $1.6 million (which reduces the Corporate Adjustment costs), resulting from the profiling of capital investment.

In 2014, the Corporate Adjustment credit will increase by $0.6 million over 2013. This is mainly due to an increase in administrative overheads of $1.1 million (which reduces the Corporate Adjustment costs), resulting from the profiling of capital investment.

NOVA SCOTIA POWER INC.
REGULATED OPERATING COSTS
FOR THE YEARS 2011 THROUGH 2017

(in Thousands of $)

	2012 Compliance	*2011 Actual*	[redacted]	*2013 Forecast*	*2014 Forecast*	*2015 Forecast*		*2016 Forecast*		*2017 Forecast*	
Executive Management	1,252	1,179	[redacted]	1,147	1,160	1,153	-0.6%	1,151	-0.1%	1,160	0.8%
Corporate Office of Secretary and General Counsel	7,481	7,079	[redacted]	8,530	8,833	9,110	3.1%	9,407	3.3%	9,738	3.5%
Corporate Finance	5,666	5,691	[redacted]	6,466	6,571	6,510	-0.9%	6,424	-1.3%	6,456	0.5%
Investor Relations, Communications and Public Affairs	2,433	2,063	[redacted]	2,360	2,394	2,398	0.2%	2,409	0.5%	2,436	1.1%
Corporate Human Resources (including Safety)	5,206	4,766	[redacted]	5,554	5,648	5,624	-0.4%	5,627	0.0%	5,677	0.9%
Facilities and Procurement	8,947	11,886	[redacted]	9,991	10,122	10,074	-0.5%	10,078	0.0%	10,175	1.0%
Information Technology	10,500	10,746	[redacted]	11,737	12,126	12,418	2.4%	12,485	0.5%	12,611	1.0%
Regulatory Affairs	5,854	6,518	[redacted]	6,332	6,236	5,749	-7.8%	5,777	0.5%	5,834	1.0%
TOTAL CORPORATE GROUPS	**47,339**	**49,928**	[redacted]	**52,117**	**53,090**	**53,037**	**-0.1%**	**53,357**	**0.6%**	**54,087**	**1.4%**
TECHNICAL & CONSTRUCTION SERVICES	**13,290**	**13,605**	[redacted]	**14,431**	**14,550**	**14,387**	**-1.1%**	**14,328**	**-0.4%**	**14,439**	**0.8%**
SUSTAINABILITY	**1,970**	**3,188**	[redacted]	**1,508**	**1,527**	**1,523**	**-0.2%**	**1,525**	**0.1%**	**1,538**	**0.9%**
Head Office	16,911	15,064	[redacted]	24,740	23,950	21,291	-11.1%	19,456	-8.6%	18,522	-4.8%
Thermal Plants	66,326	72,793	[redacted]	61,995	63,479	62,396	-1.7%	63,801	2.3%	65,241	2.3%
Combustion Turbines	1,316	1,384	[redacted]	1,272	1,301	1,328	2.1%	1,355	2.0%	1,382	2.0%
Hydro & Wind Energy	14,810	12,685	[redacted]	14,390	14,707	15,010	2.1%	15,297	1.9%	16,791	9.8%
Biomass	-	-	[redacted]	5,380	6,261	6,393	2.1%	6,526	2.1%	6,662	2.1%
Energy, Fuels and Risk Management	3,816	3,328	[redacted]	3,819	3,909	3,999	2.3%	4,086	2.2%	4,175	2.2%
TOTAL POWER PRODUCTION	**103,179**	**105,254**	[redacted]	**111,596**	**113,607**	**110,418**	**-2.8%**	**110,521**	**0.1%**	**112,773**	**2.0%**
Field Operations	23,310	24,643	[redacted]	22,542	23,094	23,619	2.3%	24,164	2.3%	24,723	2.3%
Control Center	8,062	7,318	[redacted]	7,996	8,194	8,388	2.4%	8,586	2.4%	8,789	2.4%
Transmission Operations and Reliability	16,665	18,275	[redacted]	22,382	22,866	23,326	2.0%	23,771	1.9%	24,226	1.9%
Administration (incl Storm)	17,436	18,823	[redacted]	26,331	26,315	25,096	-4.6%	24,226	-3.5%	23,930	-1.2%
TOTAL CUSTOMER OPERATIONS	**65,473**	**69,059**	[redacted]	**79,251**	**80,469**	**80,428**	**-0.1%**	**80,747**	**0.4%**	**81,668**	**1.1%**
CUSTOMER SERVICE	**32,404**	**39,932**	[redacted]	**37,026**	**37,358**	**37,265**	**-0.2%**	**37,390**	**0.3%**	**37,817**	**1.1%**
CORPORATE ADJUSTMENTS	**(17,958)**	**(19,573)**	[redacted]	**(16,895)**	**(17,507)**	**(19,297)**	**10.2%**	**(14,493)**	**-24.9%**	**(11,503)**	**-20.6%**
TOTAL OPERATING COSTS	**245,697**	**261,393**	[redacted]	**279,034**	**283,094**	**277,761**	**-1.9%**	**283,376**	**2.0%**	**290,819**	**2.6%**

NOVA SCOTIA POWER INC.

CAPITAL STRUCTURE

AND

RETURN ON COMMON EQUITY

Prepared by

KATHLEEN C. MCSHANE

foster associates

May 2012

TABLE OF CONTENTS

I. INTRODUCTION AND CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is One Church Street, Rockville, Maryland 20850. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, gas and oil pipelines, and telephone companies, in more than 200 proceedings in Canada and the U.S., including before the Nova Scotia Utility and Review Board ("UARB" or "the Board"). My professional experience is provided in Appendix A.

On November 29, 2011, the UARB approved a settlement agreement (the "GRA Agreement"), which adopted an allowed return on equity ("ROE") of 9.2%, with a target earnings range of 9.1% to 9.5%. The GRA Agreement specified that rates be set on a 37.5% common equity ratio, permitted NSPI to use a maximum actual equity ratio of 40% to calculate its actual regulated ROE and specified that the actual average equity be used to calculate the actual regulated ROE.[1] For the test period 2013 and 2014, Nova Scotia Power Inc. ("NSPI" or "the Company") is proposing to maintain the ROE and capital structure adopted in the GRA settlement and approved by the UARB. The Company has requested that I provide an expert opinion on the reasonableness of its request.

[1] NSUARB-NSPI-P-892.

B. CONCLUSIONS

NSPI's requested ROE of 9.2% on a rate setting common equity ratio of 37.5% is conservative when compared to the returns that have been recently awarded other Canadian utilities of lower risk. The requested return is materially lower than returns available to U.S. utilities of similar risk to NSPI, considering:

1. The 10.25%-11.0% ROE on an average 48% common equity ratio earned by a sample of proxy electric utilities.

2. A forecast ROE for the proxy electric utility sample of approximately 11.0% on common equity ratio of 50%.

3. The most recent allowed returns for U.S. gas and electric utilities of 9.85% to 10.35% on common equity ratios averaging 48%-49%.

4. The most recent allowed returns for the regulated operations of the proxy electric utilities, comprised of a 10.3% ROE on a common equity ratio of slightly over 50%.

NSPI's requested ROE of 9.2% is supported by the estimated 9.25% "bare bones" DCF cost of equity for the sample of proxy electric utilities. The "bare bones" cost of equity, however, excludes any allowance for financing flexibility. The addition of a minimum 0.50% allowance to the DCF cost of equity would result in an ROE of 9.75%, more than 0.50% higher than the ROE NSPI is requesting.

Finally, the overall return requested by NSPI is relatively low by comparison to the market returns of the proxy electric utilities, given that their cost of equity is applicable to common equity ratios that exceed NSPI's by a significant margin.

II. THE FAIR RETURN STANDARD

NSPI's proposal to retain the allowed ROE of 9.2% on a 37.5% common equity ratio for the 2013-2014 test period needs to be assessed within the context of the standards of a fair return. The standards for a fair return arise from legal precedents,[2] which are echoed in numerous regulatory decisions across North America. A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms and conditions.[3]

The legal precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk.

[2] The principal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

[3] The three requirements were summarized by the National Energy Board (RH-2-2004, Phase II) as follows:

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities. A fair return preserves the financial integrity of the utility, that is, it permits the utility to maintain its creditworthiness, as demonstrated by the level of its credit metrics and debt ratings. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, potentially degrading the quality of service or depriving existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that NSPI competes for capital with other Canadian regulated companies, with regulated companies globally, as well as with unregulated companies, both within Canada and globally.

In its 2011 *World Energy Outlook*, the International Energy Agency estimated that between 2011 and 2035 close to $17 trillion in investment would be required by the global electricity industry of which $10 trillion and $7 trillion respectively would be comprised of investments in generation and transmission/distribution assets.[4] The Conference Board of Canada estimates that investment in electricity infrastructure in

[4] Approximately $38 trillion world-wide in global cumulative energy infrastructure investment (2011 *World Energy Outlook*, Figure 2.20).

Canada over the period 2011 to 2030 will be close to $348 billion.[5] To compete successfully for required capital, NSPI requires returns that are competitive with those of its peers. The achievement of comparability requires explicit recognition of the financial parameters of the companies of comparable risk to NSPI, including other regulated companies throughout North America.

As NSPI is requesting to maintain the ROE and capital structure adopted for test year 2012, I have not conducted a detailed application of each of the various traditional cost of equity tests. Instead, I have assessed the reasonableness of the proposed ROE by reference to:

1. NSPI's business and financial risk profile relative to its peers.

2. An analysis of the allowed returns of NPSI's regulated Canadian peers; and

3. The returns available to NSPI's U.S. peers.

[5] Conference Board of Canada, *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure*, February 2012.

III. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The fair return (which in this context encompasses both capital structure and ROE) for NSPI should be determined on a stand-alone basis. The stand-alone principle encompasses the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the utility raising capital in the public markets on the strength of its own business and financial parameters. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources and avoid cross-subsidies. The stand-alone principle has been respected by virtually every Canadian regulator in setting both regulated capital structures and allowed ROEs.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk relates largely to the assets of the firm. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure.

Simply put, as the debt ratio rises, so do the costs of debt and equity. For a given level of business risk, the ROE that would be fair and reasonable at a common equity ratio of 40% would be lower than the return on equity that would be fair and reasonable at a common equity ratio of 30%.

IV. RISK PROFILE AND RELATIVE RISK OF NSPI

A. BUSINESS RISK

1. Overview

NSPI is an integrated electric utility providing over 95% of the electricity generated, transmitted and delivered in the Province of Nova Scotia to approximately 493 thousand residential, commercial and industrial customers. Total assets at the end of 2011 were close to $4 billion. The percentage of 2011 sales to each customer class is summarized below.

Table 1

Customer Class	Sales (GWh)
Residential	38.1%
Commercial	27.7%
Industrial	31.4%
Other	2.8%

NSPI owns and operates a vertically integrated (transmission, distribution and generation) electric utility. Close to two-thirds of its net plant is attributable to its generation function. It is one of only two investor-owned electric utilities in Canada (FortisBC being the other) which own and operate regulated facilities that generate more than a third of the power consumed by their customers.[6] There is a limited wholesale market for eligible market participants (the province's six municipally-owned electric utilities) and an Open Access Tariff, which provides for non-discriminatory access to NSPI's transmission system, allowing the eligible market participants to import power from outside the province and for competitive suppliers to import and export power into and out of the province.

[6] Maritime Electric and Newfoundland Power are considered integrated electric utilities as they have generation assets, but they are largely distribution utilities.

NSPI retains the obligation to serve, including the obligation to ensure that adequate power is available to its domestic customers, either through construction, ownership and operation of generation or by contracting for power. This obligation is in contrast to the obligations held by, for example, the electricity distributors in Ontario or Alberta. In Ontario, the distribution utilities have no obligation to ensure the availability of power. In Alberta, the distribution utilities have the supplier of last resort function only if the retailers designated as the supplier of last resort default on their commitment.

2. <u>Service Area</u>

NSPI serves a mature, relatively small economy; the 2010 Nova Scotia nominal GDP of $36 billion represents approximately 2.25% of the total GDP of Canada. The economy is a mix of resource-based (e.g., energy and forestry related) and service-based industries, as Nova Scotia serves as a regional service hub for Atlantic Canada. The province's economy has been dependent on trade, with more than 50% of its GDP directly attributed to the export of goods and services to the U.S. and other Canadian provinces.[7]

The most recent long-term provincial economic forecast issued by the Conference Board of Canada[8] anticipated that growth in Nova Scotia from 2010-2030 would be the lowest of all 10 provinces, as government austerity measures, limited private investment, and weak demographic fundamentals coalesced to slow the economy. However, that forecast predates the naval shipbuilding contract awarded Halifax Shipyard in October 2011, which is expected to enhance the province's growth prospects. Nevertheless, Nova Scotia will continue to face similar demographic challenges to those of other Atlantic Canada provinces, i.e., an aging population, lower labour participation rates, slowing growth in disposable income and slowing overall economic growth.

[7] Standard and Poor's, *Nova Scotia Power Inc.*, December 30, 2010.
[8] Conference Board of Canada, *Provincial Outlook, 2011 Long-Term Economic Forecast*, May 2011.

3. Supply

NSPI produces close to 90% of the power that it sells and purchases the remainder under power purchase contracts with independent power producers (IPPs) of renewable energy. NSPI's year-end 2011 owned generating capacity of 2,374 MW was comprised of the following technologies (by percentage):

Table 2

Technology	Percent of Capacity (MW)
Coal	52.4%
Dual Fired	14.7%
Natural Gas	12.8%
Hydroelectric	16.6%
Wind	3.5%

The IPPs with which NSPI has contracts own 229 MW of wind and biomass capacity, increasing to 259 MW in 2012. An additional 83 MW of renewable capacity expected to be in service by the end of 2013 is either being built directly by NSPI or will be purchased from IPPs by NSPI pursuant to long-term contracts.

In 2011, approximately 78% of the power delivered by NSPI was produced from fossil fuels (58% from coal), down from 83% in 2010. Under provincial government regulations, NSPI is subject to caps on greenhouse gas (GHG) emissions, with potential penalties if those caps are not met. NSPI is also subject to increasingly stringent caps on sulphur dioxide, nitrous dioxide and mercury emissions. Under the provincial government's Renewable Electricity Plan, 25% of the province's electricity requirements must come from renewable resources by 2015. The Electricity Act was amended in 2011 to mandate that 40% of the province's electricity requirements come from renewable resources by 2020. Regulations proposed by the provincial government to implement the amended legislation would require that 25% of the renewable energy resource power NSPI acquires come from firm (as contrasted with non-firm sources such as wind) electricity supply sources. The amendments would also set a cap on the amount of biomass generated electricity that can qualify for the renewable electricity standard.[9]

4. Regulation

NSPI's cost of service framework is similar to that of other North American utilities. Like most other vertically integrated utilities in North America, NSPI is able to recover from customers the difference between its forecast and actual fuel costs through a fuel adjustment mechanism (FAM). NSPI's FAM was effective January 1, 2009. The FAM was viewed positively by the debt rating agencies when it was adopted. In its November 2010 debt rating report for NSPI, DBRS commented that "The Fuel Adjustment Mechanism (FAM) which took effect on January 1, 2009, now allows for 100% fuel cost pass through, which in turn has reduced regulatory risk and volatility in NSPI's earnings." In its September 2009 report, Standard & Poor's upgraded NSPI from BBB to BBB+, in part due to the adoption of the FAM. Standard & Poor's December 2009 report concluded that "the utility's risk profile has improved with the introduction of a fuel-adjustment mechanism (FAM), which will result in pass through of fuel costs into rates."

With respect to capital projects, as noted by DBRS, "Each project must receive approval from the Nova Scotia Utility and Review Board (UARB) before NSPI can proceed to ensure that the investment will be included in the rate base."[10] This requirement is materially the same in other Canadian jurisdictions. Costs incurred in the construction of each project are, as in other jurisdictions, subject to a prudence review. On an ongoing basis, projects completed and placed into service are subject to risks that costs incurred

[9] In 2011, the federal government announced proposed regulations to reduce emissions from the coal-fired electricity generation sector. The federal regulations, expected to be finalized in 2012, and effective July 1, 2015, will phase out traditional coal-fired electricity generation plants, apply stringent performance standards to new coal-fired plants and promote investment in cleaner generation technologies. In March 2012, Environment Canada announced that it was working on an equivalency agreement with the province of Nova Scotia, which would allow the province to retain the flexibility for an approach that suits its needs, as long as it achieves the same GHG emission reductions as the federal targets. The equivalency agreement would require the province to create new targets to extend to 2030 to match reductions under the proposed federal regulations.

[10] DBRS, *Nova Scotia Power Inc.*, November 26, 2010.

for maintenance capital, operating expenses and fuel (for generation projects) will not be recoverable in rates.

Overall, DBRS considers that NSPI operates under a reasonable regulatory environment.[11] While Standard & Poor's refers to NSPI's regulatory environment as "supportive", on March 30, 2012, it changed the trend on the Company's ratings from "Stable" to "Negative", citing a meaningful capital expenditure program to address provincial and federal energy policies, driving the need for rate increases, which heightens regulatory risk.[12,13]

5. Capital Expenditures

NSPI's capital expenditures are expected to average approximately $350 million per year for the five year period 2012-2016 (total of approximately $1.75 billion), according to its 2012 Annual Capital Expenditure Plan filed in November 2011. Revisions to its prior year plan reflected the uncertainty of energy demand, particularly as a result of the closure of the NewPage Port Hawkesbury paper mill, and of the impact of the federal emissions regulations announced in 2011. While the capital expenditures to be incurred over the five-year forecast horizon have declined somewhat since the 2011 Plan, the forecast annual capital requirements remain sizeable and require ongoing access to the capital markets on reasonable terms and conditions.

[11] DBRS, *Nova Scotia Power Inc.*, March 28, 2012.

[12] Standard & Poor's, *Research Update: Nova Scotia Power Inc. Outlook to Negative From Stable On Growth Plan Stresses; 'BBB+' Ratings Affirmed*, March 30, 2012.

[13] Of the three major debt rating agencies in Canada, only Moody's, which no longer rates NSPI's debt, provides a relative regulatory risk assessment. In its last report on NSPI in 2009 prior to its discontinuation of the debt ratings, Moody's ratings for NSPI on its two regulatory risk factors (regulatory framework and ability to recover costs and earn returns) were the same as the average for other Canadian utilities that it rates. Moody's rates electric and gas utility issuers operating in the provinces of Alberta, British Columbia, Ontario and Newfoundland and Labrador.

6. Relative Business Risk of NSPI

Even with the FAM in place, as an integrated electric utility with more than 50% of its rate base invested in generation assets, NSPI faces higher business risks than the typical regulated Canadian utility. The average business risk profile ranking[14] assigned to Canadian electric and gas utilities by Standard & Poor's is "Excellent", the top category on its business risk ranking scale; NSPI is assigned a business ranking of "Strong".[15] The regulated operations of the majority of the Canadian utilities listed on Schedule 1 are largely "wires" or "pipes" operations (distribution and transmission) which face lower business risk than NSPI. Generation operations generally are exposed to higher operating and capital recovery risks than a "wires only" or "pipes only" business. Of the major capital intensive utility functions, generation is the one that is not necessarily a natural monopoly; the electric "wires" and gas distribution "pipes" are unlikely to ever be duplicated. Integrated utilities retain the obligation to ensure adequate generation capacity; "wires" utilities do not have that obligation nor do they have the same level of cost recovery risks as generation (fuel cost disallowances, operating risk or stranded costs).

While generation is generally riskier than transmission or distribution, within the generation function, there are different levels of business risk associated with different types of generation. The generation assets of FortisBC, the only other Canadian investor-owned truly integrated electric utility, are relatively low risk hydroelectric plants. Its purchased power also is primarily generated by hydroelectric plants. In contrast, NSPI's existing generation assets are more highly concentrated in higher risk coal/petroleum coke facilities. NSPI's higher risk relative to FortisBC arises from:

[14] There are six S&P business risk profile rankings, ranging from "Excellent" to "Vulnerable".

[15] S&P raised NSPI's business risk profile ranking from "Satisfactory" to "Strong" in December 2009 following implementation of the FAM.

(1) Risks related to the availability and costs of fuel and replacement costs of power if the plants are not operating. Hydroelectric generation facilities do not incur fuel costs.[16]

(2) The lower probability that FortisBC's low cost hydroelectric facilities will be replaced by alternative generating sources, which results in lower long-term competitive and stranded cost risk for FortisBC than for NSPI.

(3) The higher environmental risk (e.g., costs of environmental compliance) associated with NSPI's coal/petroleum coke facilities, as compared to FortisBC's hydroelectric plants.

(4) NSPI's renewable energy resource requirements arising from the Renewable Electricity Energy Standard Regulation.

(5) NSPI's requirements to reduce GHG emissions and other air pollutants. While FortisBC, as a British Columbia utility, also operates in a province governed by an aggressive climate change strategy, its sources of power supply, as noted above, are predominantly hydroelectric.

B. FINANCIAL RISK

As discussed in Section III above, financial risk is the additional risk borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. Credit metrics are also an important indicator of the level of financial risk. The firm's debt ratings are a further indicator of the level of financial risk, as debt ratings incorporate an overall assessment of the firm's business and financial risk, from the perspective of the bond investor.

[16] Due to its arrangements with BC Hydro (BC Hydro dispatches FortisBC's plants in exchange for power entitlements), FortisBC does not face any risk related to water availability.

NSPI is proposing to maintain the 37.5% common equity ratio that has previously been adopted for rate setting purposes and to continue to calculate its annual earnings on the basis of its actual capital structure up to a maximum common equity ratio of 40% as approved in Decision NSUARB-NSPI-P-892.

NSPI's 37.5% common equity ratio used for rate setting purposes is at the low end of the scale for regulated Canadian utilities. Of the investor-owned electric utilities in Canada, only the electric transmission utilities in Alberta, which are of lower business risk than NSPI, have allowed equity ratios lower than 37.5%. The typical common equity ratio allowed for rate setting purposes for electricity distribution utilities, which are also of lower business risk than NSPI is approximately 40%, with a range of 39% (Alberta taxable electricity distributors) to close to 45% (Newfoundland Power); (see Schedule 2 page 1 of 2). The average common equity ratio for regulated electric and gas utilities in Canada (other than NSPI) used for rate setting purposes is approximately 40%, higher than NSPI's 37.5%; (see Schedule 2 page 1 of 2). The median actual 2011 year-end common equity ratio for investor-owned utilities (other than NSPI) with rated debt was 41%, higher than NSPI's 37.5% rate setting common equity ratio (Schedule 3).

With respect to credit metrics, three credit metrics that debt rating agencies look to in their assessment of financial risk are: Earnings before Interest and Taxes (EBIT) Interest Coverage, Funds from Operations (FFO)[17] to Total Debt, and FFO Interest Coverage.[18] The latter two are important because bond investors are more concerned about cash flows available to meet interest payments than earnings *per se*. As summarized in Table 3 below, NSPI's three-year average (2008-2010) EBIT Interest Coverage, FFO to Debt Ratio and FFO Interest Coverage Ratio have been similar to or marginally lower (in the case of EBIT Interest Coverage) than the medians for other investor-owned Canadian utilities with rated debt.

[17] Funds from Operations are equal to net income plus or minus non-cash items. The principal non-cash items include depreciation and amortization, future income taxes and the equity component of AFUDC.
[18] Funds from Operations plus Interest divided by Interest.

Table 3

	EBIT Interest Coverage	FFO Interest Coverage (2008-2010)	FFO/Debt
NSPI	2.1X	3.2X	15.0%
Investor-owned Utility Median	2.3X	3.2X	14.9%

Note: Investor-owned Utility Median excludes NSPI.
Source: Schedule 4 page 1 of 2

Both DBRS and S&P have noted that NSPI is in the midst of a major capital expenditure program necessary to meet the renewable energy development initiatives mandated by the Province. DBRS expects that spending planned over the next three years will continue to produce free cash flow deficits and restrict improvements in key credit ratios.[19] S&P considers NSPI's credit metrics to be weak for the rating, although somewhat offset by the regulated nature of the cash flow, which the fuel adjustment mechanism supports. S&P also considers it possible that the credit metrics could suffer some deterioration in the near-to-medium term due to the regulatory risk of limited rate increases.[20]

Although NSPI's credit metrics have been fairly similar to those of other Canadian investor-owned utilities, NSPI's debt ratings have been lower than average. NSPI's DBRS rating is A(low), one notch lower than the investor-owned Canadian utility median of A. Its S&P rating is BBB+, one notch lower than the investor-owned Canadian utility median of A-.[21]

The lower debt ratings stem from NSPI's higher business risk compared to its Canadian peers, which has not been offset by lower financial risk (i.e., a higher common equity ratio and stronger credit metrics).

[19] DBRS, *Nova Scotia Power Inc.*, March 28, 2012.
[20] Standard & Poor's, *Research Update: Nova Scotia Power Inc. Outlook to Negative From Stable On Growth Plan Stresses; 'BBB+' Ratings Affirmed*, March 30, 2012.
[21] Before NSPI's Moody's ratings were withdrawn at the request of the Company in March 2010, its rating was Baa1, one notch lower than the median rating of A3 for all Canadian utilities rated by Moody's.

NSPI's higher business risk, lower regulated and actual common equity ratios, and lower debt ratings compared to its Canadian peers translate into a higher cost of equity. The higher cost of equity, in turn, means that NSPI's allowed ROE needs to be set at a level in excess of those awarded its Canadian peers in order to meet the three requirements of the fair return standard. While all three requirements of the fair return standard (comparability of returns, ability to attract capital, and maintenance of financial integrity and creditworthiness) are equally important, NSPI's ongoing significant capital program will require consistent access to the capital markets. A fair ROE that recognizes NSPI's higher business risk but relatively modest common equity ratio will provide a foundation for ensuring the Company's ability to attract capital on reasonable terms and conditions.

V. ALLOWED RETURNS OF CANADIAN UTILITIES

As one point of departure for my assessment of the reasonableness of NSPI's requested 9.2% ROE on a 37.5% common equity ratio for 2013-2014, I compared the request to the returns allowed for other regulated utilities in Canada. Schedule 2 details the most recent allowed ROEs and capital structures of Canadian utilities.

Prior to 2009, the preponderance of allowed ROEs in Canada were set using automatic adjustment formulas, which adjusted the allowed ROEs annually by 75% or 80% of the change in long-term Government of Canada bonds. Over the prior several years, these formulas had been increasingly criticized for (a) relying too heavily on a single variable, the Government of Canada bond yield; (b) overestimating the sensitivity of the utility ROE to changes in the Government of Canada bond yield, and (c) failing to give any weight to the comparable investment requirement of the fair return standard. Starting in 2009, the National Energy Board ("NEB"), the Alberta Utilities Commission ("AUC"), the British Columbia Utilities Commission ("BCUC"), the Newfoundland and Labrador Board of Commissioners of Public Utilities ("NL PUB"), the Ontario Energy Board ("OEB") and the Régie de l'énergie du Québec ("Régie") have all issued orders which have modified, suspended or rescinded the formulas which set the allowed returns on equity for utilities subject to their jurisdiction.

On March 19, 2009 the NEB released its cost of capital decision for TransQuébec and Maritimes Pipeline (TQM). In that decision, the NEB expressed the view that:

> there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

The NEB also noted that:

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.[22]

The NEB adopted a new cost of capital methodology for TQM, which instead of specifying separate capital structure and ROE components, expressed the allowed return as an overall after-tax return. The NEB provided calculations of the ROE implied at different capital structures to facilitate comparisons with the "traditional" capital structure/ROE approach. The implicit ROE at TQM's proposed common equity ratio of 40% was 9.7%, which represented an increase in the ROE of approximately 1.0% to 1.25% relative to the NEB's formula results for the same years for which TQM's cost of capital was set.

[22] National Energy Board, *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008,* March 2009.

Following its decision for TQM specifically, the NEB rescinded its RH-2-94 decision which adopted the automatic adjustment formula.[23] Since the NEB's rescission of the formula, Foothills Pipe Lines, Nova Gas Transmission and Westcoast Energy reached negotiated settlements with their shippers, all of which included allowed ROEs of 9.7% on 40% common equity ratios.[24] An ROE of 9.7% on 40% equity represents the most recent allowed return for NEB-regulated pipelines of reasonably comparable risk to NSPI. Both the allowed ROE and common equity ratios are higher than those requested by NSPI for 2013-2014.

In December 2009, the BCUC eliminated its automatic adjustment mechanism.[25] In so doing the Commission found the following:

> The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.
>
> In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI [Terasen Gas] for 2010, it would seem inconsistent to retain the adjustment mechanism.

The BCUC set the allowed ROE for FortisBC Energy Inc. (formerly Terasen Gas), designated the benchmark utility, effective July 1, 2009 at 9.50% on a common equity ratio of 40%. The allowed ROE for FortisBC Inc. is currently (for test year 2012) 9.9% on 40% common equity. The 9.9% ROE on 40% equity is the most recent allowed return in British Columbia for a utility of reasonably comparable (albeit somewhat lower) risk

[23] National Energy Board, *Reasons for Decision, Multi-Client, RH-R-2-94*, October 2009.
[24] National Energy Board, Order TG-03-2010, June 2010, (Foothills Pipe Line Ltd., for 2010-2012); Order TG-05-2010, September 2010, (Nova Gas Transmission Ltd., for 2010-2012); Order TG-01-2011, January 2011, (Westcoast Energy Inc., for 2011-2013).
[25] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure, Decision*, December 19, 2009.

to NSPI.[26] FortisBC's most recent allowed ROE and common equity ratio are both higher than NSPI's requested 9.2% ROE on 37.5% common equity ratio.

In December 2011, the AUC established an allowed ROE of 8.75% for 2010 and 2011 for the Alberta utilities on common equity ratios ranging from 37% (for AltaLink L.P. and ATCO Electric Transmission, both taxable electricity transmission utilities) to 43% for AltaGas Utilities Inc.[27] While the approved ROE of 8.75% is somewhat lower than NSPI's requested 9.2%, NSPI's common equity ratio for ratesetting purposes is lower than the 39% adopted for Alberta's taxable electricity distribution utilities, which, all other things equal (i.e., similar business risk) warrants a higher ROE for NSPI than 8.75%. However, NSPI is of higher business risk than an Alberta electricity distribution utility. The 45 basis point difference between NSPI's requested allowed ROE of 9.2% and the 8.75% allowed ROE for the Alberta electricity distribution utilities is a conservative recognition of NSPI's higher business and financial risk.

To put this in perspective, the common equity ratio that would fully compensate for NSPI's higher business risks relative to those adopted for Alberta utilities would be no less than 45%. The incremental risk premium that is required to compensate for the difference between the financial risk inherent in NSPI's 37.5% common equity ratio and the 45% common equity ratio that would effectively offset its higher business risks is in the range of approximately 0.60% to 1.0%.[28] Notwithstanding my view that the 8.75% ROE awarded by the AUC to the Alberta utilities was too low, the corresponding ROE for NSPI that would recognize the difference between the Company's 37.5% common equity ratio and a 45% common equity ratio would be in the range of 9.35% to 9.75%, higher than NSPI's requested 9.2%.

[26] The BCUC has initiated a cost of capital proceeding to take place during 2012, but the details and scheduling of that proceeding have not been finalized.
[27] Alberta Utilities Commission, *2011 Generic Cost of Capital, Decision 2011-474*, December 8, 2011.
[28] Appendix B describes how this range was derived.

In its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009, the OEB, in its assessment of the automatic adjustment formula, concluded that:

> The existing formula approximates this relationship [between interest rates and the equity risk premium] using a linear specification. The Board is of the view that it is unreasonable to conclude that the current formula correctly specifies this relationship, based on the passage of time, changes in financial and circumstances generally, and the empirical analyses provided by participants to the consultation and the discussion at the consultation itself. However, the Board is of the view that its current formulaic approach for determining the equity cost of capital should be reset and refined, not otherwise abandoned or subject to wholesale change.
>
> The events that unfolded earlier this year that triggered this review effectively illustrated that the Board's approach needs to be refined to reduce the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. The Board concludes that the current approach could be more robust and better guide the Board's discretion in applying the FRS [Fair Return Standard]. The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

The OEB recognized that:

> In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF [Long Canada Bond Forecast] for the current test year and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. In that same document, however, the Board noted that there was a significant difference of opinion concerning the relationship between interest rates and the ERP and that ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1.5. Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."

The OEB also stated that it:

> views the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5.

Further, the OEB noted that four participants in the cost of capital consultation had empirically tested the relationship between government bond yields and ROE. The four analyses summarized by the OEB all showed that the utility cost of equity changes by no more than 50% of the change in the long-term government bond yield.

The OEB reset the benchmark allowed ROE at a forecast long-term Canada bond yield of 4.25% and an approximately 140 basis point spread of A-rated utility bond yields over long Canada bond yields, at 9.75%, and confirmed the equity ratio applicable to the electricity distribution utilities at 40%. Under the previous formula, the benchmark allowed ROE would have been 8.41%. The most recent ROE that has been officially adopted by the OEB by the application of the revised formula was 9.12% for electricity distribution rates effective May 1, 2012, based on a forecast long-term Canada bond yield of 2.93%,[29] less than 10 basis points below the ROE requested by NSPI. The Ontario electricity distributors have lower business risk and lower financial risk (higher common equity ratio) than NSPI. Hence, the comparable risk-adjusted allowed ROE for NSPI should be higher than that allowed for the Ontario electricity distributors.

Further, long-term Canada bond yields are expected to rise during NSPI's 2013-2014 test period. The 9.12% ROE was based on the January 2012 consensus forecast of 10-year Government of Canada bond yields for 2012 of 2.35%. (Consensus Economics, *Consensus Forecasts*, January 9, 2012). The April 10, 2012 *Consensus Forecasts* anticipates that the average 2013-2014 10-year Government of Canada bond yield will be approximately 0.75% higher. As it is unlikely that spreads between long-term A rated utility and Government of Canada bond yields are likely to narrow more than the forecast increase in the long-term Government of Canada bond yield, the application of the OEB automatic adjustment formula is thus likely to produce higher allowed ROEs for rates effective in 2013 and 2014 than the 9.12% recently calculated for rates effective May 1, 2012.

[29] Ontario Energy Board, *Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*, March 2, 2012.

In July 2010, the Island Regulatory and Appeals Commission (IRAC) approved Maritime Electric's requested ROE of 9.75% for 2010 and 2011 on 40% equity and declined to adopt an automatic adjustment formula for ROE as proposed by the Consumer Advocate's expert witness, stating that it "sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated."[30] Maritime Electric's allowed ROE will remain at 9.75% until at least March 1, 2013. Maritime Electric is of relatively comparable risk to NSPI.

Only two regulatory jurisdictions in Canada have continued to rely on automatic adjustment formulas that incorporate a high degree of sensitivity of the allowed ROE to changes in long-term Government of Canada bond yields, the NL PUB and the Régie.

In its December 2009 decision for Newfoundland Power,[31] the NL PUB determined that an automatic adjustment formula for ROE was fundamental to its regulatory regime. The allowed ROE for 2010 was set at 9.0% (on a common equity ratio of 44.7% and assuming a forecast long-term Canada bond yield of 4.5%). The formula adopted by the NL PUB was similar to the one it had originally adopted in 1998; it changed the allowed ROE by 80% of the change in long-term Canada bond yields. The construction of the automatic adjustment formula combined with a material decline in forecast long-term Canada bond yields resulted in a significant reduction to the allowed ROE for 2011; at 8.38%, Newfoundland Power's allowed ROE for 2011 was the lowest of all major Canadian utilities governed by regulatory decisions issued since the wide-spread review of automatic adjustment formulas in 2009. With long-term Canada bond yields currently at artificially low levels, resulting largely from global factors (e.g., high demand for high quality risk-free assets), the operation of the formula would produce an even lower ROE for 2012. However, the NL PUB has agreed to suspend the formula and to review Newfoundland Power's 2012 cost of capital. Due to the formulaic nature of

[30] The Island Regulatory and Appeals Commission, *Order UE10-03, IN THE MATTER of an application by Maritime Electric Company Limited for approval of amendments to rates, tolls and charges*, July 12, 2010.
[31] Newfoundland and Labrador Board of Commissioners of Public Utilities, *Reasons for Decision: Order No. P.U.43(2009)*, December 24, 2009.

Newfoundland Power's most recently determined ROE, it is not an appropriate benchmark for assessing the reasonableness of NSPI's requested ROE.

In 2011, the Régie reviewed Gaz Métro's cost of capital, adopted an ROE of 8.9% at a forecast long-term Canada bond yield of 4.0% on a common equity ratio of 38.5% and revised the automatic adjustment formula for ROE. The "old" formula changed Gaz Métro's allowed ROE by 75% of the change in the forecast 30-year Government of Canada bond yield. The revised formula maintained the same sensitivity of the ROE to the Government of Canada bond yield but added a second variable. Gaz Métro's allowed ROE will now change by 75% of the change in the forecast 30-year Canada bond yield and by 50% of the change in the spread between 30-year A rated utility and Government of Canada bond yields. The formula is expected to operate through 2015. Similar to the currently suspended NL PUB automatic adjustment formula, the Régie's formula overstates the sensitivity of the utility cost of equity to long-term Canada bond yields.[32] Nevertheless, since the 2012 ROE was established "from first principles", rather than formulaically, and is premised on a long-term Canada bond yield (4.0%) that can be reasonably expected to prevail during NSPI's 2013-2014 test period, it is a relevant comparator to NSPI's requested 9.2% ROE. NSPI is, in my view, a higher risk utility than Gaz Métro, as its lower bond ratings indicate; as such, its cost of equity is higher and its allowed ROE should be higher to compensate for its higher risk.

[32] This conclusion can be tested using U.S. utility allowed ROEs as a proxy for the utility cost of equity. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers. (The same analysis cannot be performed using Canadian utility allowed ROEs due to the widespread use of formulas that specified the relationship between government bond yields and allowed ROEs over much of the past two decades. Thus, the exhibited relationship would be a tautology).

The quarterly allowed ROEs from 1998Q1 to 2012Q1 were regressed against long-term Treasury bond yields lagged by six months. The government bond yields were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based. The results of the analysis indicated that the utility ROE increased or decreased on average over this period by approximately 50 basis points for every one percentage point increase or decrease in long-term Treasury bond yields. Using long-term A-rated utility bond yields lagged by 6 months as the independent variable, the analysis indicates that the ROE increases or decreases by approximately 40 basis points for every one percentage point increase or decrease in the A-rated utility bond yield. Both tests show that, on average, since 1998, the sensitivity of the utility cost of equity to changes in bond yields has been materially lower than the 75% to 80% factors used in the NL PUB and Régie automatic adjustment formulas.

Based on the recent allowed returns for Canadian utilities in isolation, NSPI's requested overall allowed return, i.e., the combination of ROE and common equity ratio for rate setting purposes, is somewhat low, on a risk-adjusted basis, relative to those most recently awarded other Canadian utilities.

VI. ALLOWED RETURNS OF U.S. UTILITIES

The allowed returns for U.S. utilities are also a relevant benchmark for assessing the reasonableness of NSPI's proposed ROE and deemed common equity ratio. As a February 23, 2009 report prepared by Macquarie Research (prior to any of the above referenced decisions) entitled *ROE Formula May Finally Bite the Dust* concluded:

> Lack of comparability between allowed utility ROEs and returns on similar investments is driving the emerging capital access problem. In support of the argument the comparability criterion is not being met, utility customers and their expert witnesses like to point out that allowed returns for U.S. utilities are considerably higher than allowed returns in Canada. No matter how we slice the data, we concur with this opinion.

As reported by Regulatory Research Associates (RRA), the average ROE allowed for U.S. electric utilities from the beginning of 2011 to the end of the first quarter 2012 was approximately 10.35% on an average common equity ratio of 48% (53 cases).[33] The corresponding average ROE adopted for the generally lower business risk U.S. gas distribution utilities was approximately 9.85% on common equity ratios averaging of 49% (21 cases).[34]

As discussed in further detail in Section VII below, I have also selected a sample of publicly-traded U.S. electric utilities of comparable risk to NSPI for purposes of

[33] The average includes returns allowed by state regulators for distribution utilities, integrated electric utilities and regulated generation investments, but excludes returns allowed by the FERC for transmission investments. The first quarter 2012 average awarded ROE reported by RRA excluding ROEs granted for regulated generation investments was 10.3%.

[34] Regulatory Research Associates, *Regulatory Focus, Major Rate Case Decisions -- Calendar 2011*, January 10, 2012 and *Regulatory Focus, Major Rate Case Decisions -- January-March 2012,* April 5, 2012.

estimating the discounted cash flow cost of equity. The median allowed ROE that was adopted for the operating subsidiaries of the traded companies in decisions issued during 2011 to April 24, 2012 was 10.35% on a common equity ratio of approximately 52% (Schedule 5). Over the past five years (2007-2011), the actual returns on average equity achieved by the parent companies averaged 11.0% (median of 10.2%), and *Value Line* forecasts anticipate that sample return on average common equity will be approximately 11.0% over the next five years (Schedule 6).

NSPI's proposed ROE of 9.2% on a common equity ratio of 37.5% for rate setting purposes results in an allowed overall return well below those returns available to U.S. electric and gas distribution utilities of reasonably comparable risk to NSPI. Even if the U.S. utilities were viewed as facing somewhat higher business risk than NSPI, the difference in their equity ratios of more than 10 percentage points more than offsets that difference. In isolation, on the basis of allowed, earned and expected ROEs of U.S. utilities, a reasonable ROE for NSPI would be no less than 10.0%.

VII. MARKET RETURNS OF COMPARABLE RISK U.S. ELECTRIC UTILITIES

Since the purpose of this report was to test the reasonableness of NSPI's proposal to maintain the previously approved ROE and capital structure, I did not conduct all of the traditional tests used to establish a fair and reasonable return (Discounted Cash Flow, Equity Risk Premium, Capital Asset Pricing Model, Comparable Earnings). I did however, consider the expected market returns of a sample of integrated U.S. electric utilities selected explicitly to be of comparable risk to NSPI using estimates of their cost of attracting equity capital using the Discounted Cash Flow (DCF) test.

In Canada, there are only six publicly-traded Canadian companies whose operations are largely regulated.[35] These companies are relatively heterogeneous in terms of both

[35] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., TransCanada Corporation and Valener Inc. (formerly Gaz Métro LP).

operations[36] and size.[37] The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

Emera Inc. is the only publicly-traded integrated electric utility in Canada.[38] I did not apply the DCF models specifically (or solely) to Emera Inc., NSPI's parent, for three reasons.

First, while Emera Inc. is primarily an electric utility, any DCF estimate which relies only on data for a single company is subject to measurement error. Measurement error results when the forecast of growth used in the DCF model does not equate to the investors' expectation of growth that is embedded in the dividend yield component. By relying on a sample of companies, the amount of "measurement error" in the data can be reduced. The larger the sample, the more confidence the analyst has that the sample results are representative of the cost of equity. As noted in a widely utilized finance textbook:

> Remember, [a company's] cost of equity is not its personal property. In well-functioning capital markets investors capitalize the dividends of all securities in [the company's] risk class at exactly the same rate. But any estimate of [the cost of equity] for a single common stock is noisy and subject to error. Good practice does not put too much weight on single-company cost-of-equity estimates. It collects samples of similar companies, estimates [the cost of equity] for each, and takes an average. The average gives a more reliable benchmark for decision making.[39]

Second, the application of the DCF test to the "subject" utility entails considerable circularity.

---

[36] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.

[37] Ranging from an equity market capitalization of approximately $610 million (Valener) to $26.5 billion (Enbridge).

[38] FortisBC is part of Fortis Inc., whose two largest utility investments are FortisBC Energy Inc., a gas distribution utility and FortisAlberta, an electric distribution utility. Fortis Inc. is currently in the process of acquiring CH Energy Inc., a U.S. electric distribution utility based in New York State.

[39] Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, Eighth Edition, Boston, MA: Irwin McGraw Hill, 2006, p. 67 (emphasis added).

Third, the application of the DCF test solely to Emera Inc. is incompatible with the comparable returns criterion for estimating a fair and reasonable return. It is the performance of companies comparable to the utility in terms of risk that must be the focus of the return on equity analysis.

U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the cost of equity for NSPI. The operating (or business) environments are similar, the regulatory model in the U.S. is similar to the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar.

Equity markets are global; investors are increasingly committing equity funds beyond domestic borders. Canadian investors looking to commit funds to utility equity shares will compare returns available from Canadian utilities to returns available from utility shares globally, including returns from U.S. utilities (both market and allowed). A review of the major Canadian public sector defined benefit pension funds which list all their equity holdings individually shows that the funds have invested in a significant number of U.S. utilities.

To ensure that the electric utilities chosen are of comparable risk to NSPI, the following selection criteria were applied:

1. Classified in Edison Electric Institute's *2010 Financial Review* as a regulated or mostly regulated electric utility;

2. Preponderance of electric utility operations in states that have not restructured their electric utility industry or have suspended restructuring;

3. Paid dividends quarterly from 2002 to 2011, or since the initiation of trading of common shares;

4. Analysts' long-term earnings forecasts available from three of the four following sources: Bloomberg, Reuters, *Value Line* and Zacks;

5. Standard & Poor's and Moody's debt ratings of BBB/Baa2 or higher; and

6. Not being acquired or part of a merger.

Application of the six selection criteria resulted in a sample of 15 companies. The individual companies, along with company-specific data, are listed on Schedule 6.

The selected electric utilities are in Standard & Poor's "Strong" or "Excellent" business risk category, with a sample median of "Excellent". The typical Canadian utility has an "Excellent" business risk ranking; NSPI is ranked "Strong"; i.e., of higher business risk than the typical Canadian utility and of higher business risk than the typical utility in the proxy U.S. electric utility sample from S&P's perspective. The U.S. electric utilities are rated no lower than BBB/Baa2 by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. electric utility sample is A-, higher than NSPI's rating. The median Moody's rating for the U.S. electric utility sample is Baa1; NSPI's Moody's rating was also Baa1 before it was withdrawn by the Company in March 2010 (Schedules 1and 6).

The median *Value Line* Safety rank of the U.S. electric utility sample is 2 (Schedule 6); the Safety ranks of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and Enbridge Inc.) are 2 and 1 respectively.[40] In comparison to NSPI, the U.S. utilities have higher common equity ratios (lower financial risk). The average common equity ratio of the sample of U.S. electric utilities during 2011 was approximately 48% (Schedule 6), compared to NSPI's deemed common equity ratio for

[40] The Safety rank represents Value Line's assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

rate setting purposes of 37.5% and the 40% common equity ratio on which the Company is allowed to earn.

My DCF analysis for the proxy sample of U.S. electric utilities was based on both constant growth and three-stage growth models.

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows.

The constant growth DCF model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries, e.g. utilities.

The constant growth DCF model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[41]

$\mathbf{P_o}$ = current price

$\mathbf{g}$ = constant growth rate

[41] Alternatively expressed as $\mathbf{D_o\ (1 + g)}$, where $\mathbf{D_o}$ is the most recently paid dividend.

The constant growth DCF model was applied to the sample of U.S. electric utilities using the following inputs to calculate the dividend yield:

1. the most recent annualized dividend paid as of March 15, 2012 as $\mathbf{D_o}$; and,

2. the average of the daily close prices for the period December 16, 2011 to March 15, 2012 as $\mathbf{P_o}$.

The constant growth model was applied to the U.S. sample using two estimates of long-term growth. The first estimate reflects the consensus of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg, Reuters, *Value Line* and Zacks. Bloomberg[42] and Reuters[43] are both global providers of real time financial news and data. *Value Line* provides investment research and forecasts for approximately 1,700 large capitalization stocks as well as investment research on 1,800 mid and small capitalization stocks. Its publications are broadly accessible to both individual and institutional investors. Zacks provides consensus estimates and ratings for approximately 4,500 U.S. and Canadian companies that have at least one sell-side analyst covering them. In general, all of these long-term earnings forecasts refer to a period of between three and five years and are intended to represent the normalized ("smoothed") rate of earnings growth over a business cycle. The consensus earnings forecasts are reflective of the analyst community's views and, therefore, are a reasonable proxy of (unobservable) investor growth expectations.

As an alternative to the consensus of investment analysts' earnings forecasts, constant growth DCF costs of equity for the sample were estimated based on sustainable growth rates derived from *Value Line* forecasts of returns on equity, earnings retention rates and earnings per share growth from external financing.

[42] Bloomberg data are available for a fee on the internet and through "Bloomberg terminals". Bloomberg has offices in more than 200 places around the world.

[43] Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries. Reuters is part of Thomson Reuters, which also publishes I/B/E/S and First Call consensus earnings growth estimates.

Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (B) expected to be retained multiplied by expected return on equity (R). The external financing portion of the sustainable growth rate is estimated as the forecast growth in the number of shares of common stock outstanding (S) multiplied by the equity accretion rate (V) which is the fraction of sales of new equity investment expected to accrue to existing stockholders. The V term is calculated as 1-Book Value/Market Price per share. The sustainable growth rate is then calculated as the sum of B*R and S*V. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.[44]

The results of the two constant growth models applied to the U.S. electric utility sample are presented in the table below and indicate an estimated DCF cost of equity for the electric utility sample of approximately 9.3%.

Table 4

Constant Growth Model Results:	**Average**	**Median**
Consensus Earnings Growth Forecasts	9.7%	9.9%
Sustainable Growth Forecasts	8.9%	8.6%
Mid-Point	**9.3%**	**9.3%**

Source: Schedules 7 and 8.

The three-stage growth model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts of earnings growth for the individual companies in the near-term (Stage 1), to migrate to the expected long-run

[44] The development of the sustainable growth rates is set forth on Schedule 8.

nominal rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term nominal GDP growth in the long term (Stage 3).

The use of forecast GDP growth in a multi-stage model as the proxy for the rate of growth to which companies will migrate over the longer term is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

Using the three-stage growth DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

The cash flow per share in Year 1 is equal to:
Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:
Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

For Years 6 through 10, cash flow is defined as:
Cash Flow $_{t-1}$ x (1 + Stage 2 Growth)

Cash flows from Year 11 onward are estimated as:
Cash Flow t-1 x (1 + GDP Growth)

The long-run (2014-2023) expected nominal rate of growth in GDP is 4.9% based on the consensus of economists' forecasts found in Blue Chip *Economic Indicators*, March 2012.[45] The average and median three-stage DCF model estimates of the cost of equity for the U.S. electric utility sample (Schedule 9) were both 9.2%.

The results of the constant growth and three-stage DCF models indicate an estimated "bare bones" cost of equity of approximately 9.25%. A cost of equity of 9.25% is similar to the 9.2% ROE proposed by NSPI. Further, adding a minimum financing flexibility adjustment of 0.50%, as has been the practice in Canada, to the sample's cost of equity results in an ROE of approximately 9.75%. The estimated proxy sample DCF costs of equity relate to an actual book value common equity ratio that is approximately 10 percentage points higher than NSPI's rate setting common equity ratio of 37.5% (Schedule 6). As a result, the estimated DCF cost of equity for the proxy sample represents a conservative estimate of the cost of equity for NSPI, as no adjustment has been made to the sample's cost of equity to take account of NSPI's lower common equity ratio. [46]

[45] Blue Chip *Economic Indicators* publishes long-term consensus forecasts twice annually, in March and October.

[46] The cost of equity, in principle, relates to market value capital structures. The market value equity ratio of the proxy utility sample coincident with the DCF cost of equity estimates was close to 60% (Schedule 10).

VIII. CONCLUSIONS

In summary, the NSPI's requested 9.2% ROE on a common equity ratio for rate setting purposes of 37.5% is somewhat low compared to the returns recently awarded other Canadian utilities when NSPI's higher overall risk is taken into account. In comparison to the returns available to U.S. utilities of similar risk, the requested return is materially lower. NSPI's proposed 9.2% ROE on a common equity ratio of 37.5% is well below:

1. The 10.25%-11.0% ROE on an approximately 48% common equity ratio (based on total capital) which has been earned by the proxy electric utilities.

2. The ROEs forecast to be earned by the proxy utilities of approximately 11.0% on a permanent capital common equity ratio of 50%.

3. The most recent allowed returns for U.S. gas and electric utilities of 9.85% to 10.35% on common equity ratios averaging 48%-49%.

4. The most recent allowed returns for the regulated operations of the proxy electric utilities, comprising a 10.3% ROE on a common equity ratio slightly over 50%.

Finally, NSPI's requested ROE of 9.2% is similar to the "bare bones" DCF cost of equity estimated at 9.25% for the sample of proxy electric utilities. It is, however, low considering that the addition of a minimum allowance for financing flexibility of 0.50% would result in an ROE of 9.75%. The overall return requested by NSPI is also relatively low by comparison, considering that the common equity ratio maintained by the proxy electric utilities is on average approximately ten percentage points higher than NSPI's 37.5% rate setting common equity ratio.

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.*, presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Alberta Natural Gas
1994

Alberta Utilities Generic Cost of Capital
2011

AltaGas Utilities
2000

Ameren (Central Illinois Public Service)
2000, 2002, 2005, 2007 (2 cases),
2009 (2 cases)

Ameren (Central Illinois Light Company)
2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Illinois Power)
2004, 2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Union Electric)
2000 (2 cases), 2002 (2 cases), 2003,
2006 (2 cases)

ATCO Electric
1989, 1991, 1993, 1995, 1998, 1999, 2000,
2003, 2010

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007, 2011

ATCO Utilities
(Generic Cost of Capital) 2008

Bell Canada
1987, 1993

Benchmark Utility Cost of Equity (British Columbia)
1999

Canadian Western Natural Gas
1989, 1996, 1998, 1999

Centra Gas B.C.
1992, 1995, 1996, 2002

Centra Gas Ontario
1990, 1991, 1993, 1994, 1995

Direct Energy Regulated Services
2005

Dow Pool A Joint Venture
1992

Electricity Distributors Association
2009

Enbridge Gas Distribution
1988, 1989, 1991, 1992, 1993, 1994, 1995,
1996, 1997, 2001, 2002

Enbridge Gas New Brunswick
2000, 2010

Enbridge Pipelines (Line 9)
2007, 2009

Enbridge Pipelines (Southern Lights)
2007

EPCOR Water Services Inc.
1994, 2000, 2006, 2008, 2011

FortisBC
1995, 1999, 2001, 2004

FortisBC Energy Inc.
1992, 1994, 2005, 2009, 2011

FortisBC Energy (Whistler) Inc.
2008

Gas Company of Hawaii
2000, 2008

Gaz Métro
1988

Gazifère
1993, 1994, 1995, 1996, 1997, 1998, 2010

Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)
2003

Heritage Gas
2004, 2008, 2011

Hydro One
1999, 2001, 2006 (2 cases)

Insurance Bureau of Canada (Newfoundland)
2004

Laclede Gas Company
1998, 1999, 2001, 2002, 2005

Laclede Pipeline
2006

Mackenzie Valley Pipeline
2005

Maritime Electric
2010

Maritimes NRG (Nova Scotia) and (New Brunswick)
1999

MidAmerican Energy Company
2009

Multi-Pipeline Cost of Capital Hearing (National Energy Board)
1994

Natural Resource Gas
1994, 1997, 2006, 2010

New Brunswick Power Distribution
2005

Newfoundland & Labrador Hydro
2001, 2003

Newfoundland Power
1998, 2002, 2007, 2009, 2012

Newfoundland Telephone
1992

Northland Utilities
2008 (2 cases)

Northwestel, Inc.
2000, 2006

Northwestern Utilities
1987, 1990

Northwest Territories Power Corp.
1990, 1992, 1993, 1995, 2001, 2006

Nova Scotia Power Inc.
2001, 2002, 2005, 2008, 2011

Ontario Power Generation
2007, 2010

Ozark Gas Transmission
2000

Pacific Northern Gas
1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009

Plateau Pipe Line Ltd.
2007

Platte Pipeline Co.
2002

St. Lawrence Gas
1997, 2002

Southern Union Gas
1990, 1991, 1993

Stentor
1997

Tecumseh Gas Storage
1989, 1990

Telus Québec
2001

TransCanada PipeLines
1988, 1989, 1991 (2 cases), 1992, 1993

TransGas and SaskEnergy LDC
1995

Trans Québec & Maritimes Pipeline
1987

Union Gas
1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001

Westcoast Energy
1989, 1990, 1992 (2 cases), 1993, 2005

Yukon Electrical Company
1991, 1993, 2008

Yukon Energy
1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Greater Toronto Airports Authority	Financial Performance Metrics	2012
Heritage Gas	Criteria for a Mature Utility	2011
Alberta Utilities	Management Fee on CIAC	2011
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
Nova Scotia Power	Calculation of ROE	2009
Alberta Oilsands Pipeline	Cash Working Capital	2007
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998

Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Métro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

APPENDIX B
DEVELOPMENT OF INCREMENTAL EQUITY RISK PREMIUM FOR NSPI

RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

There are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks, and then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or "benchmark". The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

Both of these approaches have been taken by regulators in Canada. The first approach has been employed by the Alberta Utilities Commission and its predecessor, the Alberta Energy and Utilities Board, in their generic cost of capital decisions (Decision 2004-052, July 2004, Decision 2009-216, November 2009 and Decision 2011-474). The second approach has been taken by the British Columbia Utilities Commission and the Régie de l'énergie de Québec.

Both approaches are valid as long as the combination of capital structure and return on equity for a particular utility produces a reasonable balance of capital structure and ROE and compensates equity shareholders for the utility's business risk relative to that of its peers or the benchmark.

Each of the approaches recognizes that the cost of capital is largely a function of business risk. Business risk comprises the operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. In other words, business risk is a function of the fundamental characteristics of the operations, i.e., of the firm's assets. The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares – to finance a portion of its assets. The capital structure, comprised of debt, preferred shares and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for corporate income tax purposes and costs associated with the use of excessive debt (bankruptcy, financial distress, loss of operating/financial flexibility), the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used. However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will be accompanied by an increase in the cost of equity. The amount by which the cost of common equity increases for a given increase in the debt ratio can be estimated under each of three approaches:

Approach 1 is based on the theory that the overall after-tax cost of capital and the pre-tax cost of capital do not change materially over a relatively broad range of capital structures. This approach effectively assumes that the benefit of the deductibility of interest expense for corporate income tax purposes (which would tend to lower the overall cost of capital) is offset by personal income taxes on interest.

Approach 2 is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

Approach 3 assumes for utility cost of capital purposes that the corporate income tax rate is zero. The underlying premise is that the benefits of the corporate tax deductibility of interest accrue to rate payers, not shareholders, as is the case with unregulated companies. As with the first approach, the overall cost of capital remains unchanged as the capital structure changes. However, since the cost of capital in Approach 3 contains no income tax component, the impact on the cost of equity due to changing leverage is less than in the presence of corporate income tax and interest deductibility. When the corporate income tax rate is zero, the results of Approaches 1 and 2 are identical to the results estimated using Approach 3.

To estimate the incremental risk premium required to compensate for the difference between the financial risk inherent in NSPI's 37.5% common equity ratio and the 45% common equity ratio that would more closely align its total risk (business plus financial) to that of its Alberta peers, the following steps were taken:

1. Estimate NSPI's weighted average cost of capital using a common equity ratio of 45%, a cost of long-term debt equal to 5.35%,[47] an ROE of 8.75% equal to the most recent ROE awarded by the Alberta Utilities Commission and a statutory corporate income tax rate of 31% (combined corporate Federal/Nova Scotia income tax rate for 2013).

2. Use Approaches 1 to 3 to estimate the incremental risk premium required to account for the difference in financial risk between a 37.5% and a 45% common equity ratio.

[47] The 5.35% cost of new debt reflects a forecast long-term Government of Canada bond yield of 4.0% plus a spread of 135 basis points, with the latter equal to the March 2012 spread between the yields on long-term A- rated Canadian utility and Government of Canada bonds.

Table B-1 below shows the adjustments to the cost of equity that are required to recognize the difference in financial risk between common equity ratios of 37.5% and 45% based on the assumptions set out above and the three Approaches.

Table B-1

Approach	Increase in Cost of Equity
Approach 1	1.0%
Approach 2	0.6%
Approach 3	0.7%

Schedule 11 provides the formulas for estimating the change in the cost of equity due to capital structure differences under each of the three approaches.

DEBT RATINGS OF CANADIAN UTILITIES

	Ratings						
	DBRS		Moody's		S&P		
Company	Issuer Rating	Debt Rating	Issuer Rating	Debt Rating	Corporate Credit Rating	Debt Rating	S&P Business Risk Profile
Electric Utilities							
AltaLink L.P.		A (Senior Secured)			A-	A- (Senior Secured)	Excellent
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured)	Excellent
Enersource	A	A (Senior Unsecured)					
ENMAX Corp.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
ENTEGRUS Inc. [1]					A		Excellent
EPCOR Utilities Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
FortisAlberta Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
FortisBC Inc.		A(low) (Unsecured)		Baa1 (Senior Unsecured)			
Guelph Hydro Electric Systems					A	A (Senior Unsecured)	Excellent
Hamilton Utilities					A	A (Senior Unsecured)	Excellent
Hydro One Inc.		A(high) (Senior Unsecured)		Aa3 (Senior Unsecured) [2]	A+ [2]	A+ (Senior Unsecured) [2]	Excellent
Hydro Ottawa Holding Inc.		A (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
London Hydro					A		Excellent
Maritime Electric					BBB+	A- (Senior Secured)	Strong
Newfoundland Power		A (First Mortgage)	Baa1 [3]	A2 (First Mortgage) [3]			
Nova Scotia Power		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Ontario Power Generation		A(low) (Unsecured)			A-		Strong
Toronto Hydro		A(high) (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
Veridian Corp.	A						
Gas Distributors							
Enbridge Gas Distribution		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
FortisBC Energy Inc. [4]		A (Unsecured)		A3 (Senior Unsecured) A1 (Senior Secured)	A	A (Senior Unsecured) AA- (Senior Secured)	
FortisBC Energy Inc. (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)			
Gaz Métro Inc.		A (First Mortgage)			A-	A (Senior Secured)	Excellent
Pacific Northern Gas [5]		BBB(low) (Senior Secured)					
Union Gas Limited		A (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Pipelines							
Enbridge Pipelines Inc.		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
NOVA Gas Transmission Ltd.		A (Unsecured)		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
TransCanada PipeLines Ltd.		A (Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
Westcoast Energy Inc.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Medians							
Electric Utilities		**A**		**A3**	**A**	**A/A-**	**Excellent**
Gas Distributors		**A**		**A3**	**A-**	**A**	**Excellent**
Pipelines		**A**		**A3**	**A-**	**A-**	**Excellent/Strong**
All Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Investor Owned Companies		**A**		**A3**	**A-**	**A-**	**Excellent**

[1] Previously Chatham-Kent Energy Inc.
[2] Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.
[3] Ratings withdrawn at request of company March 2010; unsecured debt previously rated Baa1.
[4] S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.
[5] DBRS rating discontinued March 12, 2012.

Source: www.dbrs.com, www.moodys.com, Standard & Poor's, *Issuer Ranking: Canadian Utilities and Pipelines, Strongest to Weakest (February 24, 2012)*.

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Electric Utilities									
AltaLink	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
ATCO Electric									
Transmission	12/11	AUC	2011-474	52.81	10.19	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	50.95	10.05	39.00	8.75	3.60	
ENMAX									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
EPCOR									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisAlberta Inc.	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	4.30	
Hydro One Transmission	12/10; 3/12	OEB	EB-2010-0002; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a	[1/]
Newfoundland Power	12/09; 12/10	NLPub	P.U. 46 (2009); P.U. 32 (2010)	54.27	1.04	44.69	8.38	3.72	
Nova Scotia Power	11/11	NSUARB	2011 NSUARB 184	53.30	9.20	37.50	9.20	n/a	
Ontario Electricity Distributors	12/09; 3/12	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.55	3.85	
Gas Distributors									
ATCO Gas	12/11	AUC	2011-474	53.09	7.91	39.00	8.75	3.60	
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
FortisBC Energy Inc.	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	4.30	
FortisBC Energy (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	4.30	
Gaz Métro	11/11	Régie	D-2011-182	54.00	7.50	38.50	8.90	4.00	
Pacific Northern Gas-West	12/09; 5/10	BCUC	G-158-09; G-84-10	51.15	3.85	45.00	10.15	4.30	
Union Gas	1/04; 5/06; 1/08	OEB	RP-2002-0158; EB-2006-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23	
Gas Pipelines									
Foothills Pipe Lines Ltd.	6/10	NEB	TG-03-2010	60.00	0.00	40.00	9.70	n/a	
Nova Gas Transmission Ltd.	9/10	NEB	TG-05-2010	60.00	0.00	40.00	9.70	n/a	
TransCanada PipeLines	5/07; 11/10	NEB	RH-2-94;TG-06-2007; NEB Letter 11-10	60.00	0.00	40.00	8.08	3.72	
Trans Québec & Maritimes Pipeline	3/09; 11/10	NEB	RH-1-2008; TG-07-2010	60.00	0.00	40.00	9.70	n/a	[2/]
Westcoast Energy	1/11	NEB	TG-01-2011	60.00	0.00	40.00	9.70	n/a	

[1/] In 2010, the Electric Power Amendment Act reduced electricity rates and froze them until March 2013.
[2/] Settlement for 2010-2012 does not specify return on rate base; AFUDC rate, income taxes and capital variances based on a 9.7% ROE, 60%/40% debt/equity capital structure and TQM's embedded cost of debt.

Source: Regulatory Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Electric Utilities																					
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[1/]	[1/]	[1/]	[1/]	[1/]	[1/]	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00
FortisBC Inc. [3/]	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87	9.90
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95	9.00
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	NA	9.35	NA
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01	9.85
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[1/]	[2/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.88**	**9.29**
Gas Distributors																					
AltaGas Utilities	NA	13.50	13.25	NA	NA	12.00	11.75	11.75	11.75	11.75	9.90	9.70	9.70	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	9.00	9.00
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39	8.39
FortisBC Energy [3/]	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47	9.50
Gaz Métro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76	9.20
Pacific Northern Gas [3/]	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12	10.15
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.60**	**13.09**	**12.51**	**11.65**	**12.03**	**11.69**	**11.07**	**10.48**	**9.96**	**9.84**	**9.68**	**9.68**	**9.73**	**9.52**	**9.51**	**8.96**	**8.58**	**8.77**	**8.75**	**9.11**
Gas Pipelines (NEB)																					
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**	**8.57**	**8.52**
Mean of All Companies	**13.68**	**13.56**	**12.97**	**12.16**	**11.50**	**12.12**	**11.39**	**10.93**	**10.30**	**9.69**	**9.80**	**9.69**	**9.62**	**9.70**	**9.59**	**9.51**	**9.01**	**8.65**	**8.77**	**8.79**	**9.10**

[1/] Negotiated settlement, details not available.
[2/] Negotiated settlement, implicit ROE made public is 10.5%.
[3/] Allowed ROE for 2009 for first six months
[4/] Rate cases ongoing for 2012.

Note: The allowed ROEs for ENMAX Distribution, EPCOR Distribution and EPCOR Transmission have been identical to those of the other Alberta utilities since 2004 (ENMAX Transmission since 2006).

Source: Regulatory Decisions

Schedule 3

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2011)

Company	Total Debt [4/]	Preferred Stock [5/]	Common Stock Equity [6/]
Electric Utilities			
AltaLink L.P.	56.7%	0.0%	43.3%
CU Inc.	56.0%	6.9%	37.2%
Enersource [1/]	55.0%	0.0%	45.0%
ENMAX Corp.	45.6%	0.0%	54.4%
ENTEGRUS Inc. [1/ 7/]	40.2%	0.0%	59.8%
EPCOR Utilities Inc.	42.0%	0.0%	58.0%
FortisAlberta Inc.	57.4%	0.0%	42.6%
FortisBC Inc.	58.4%	0.0%	41.6%
Guelph Hydro Electric Systems [1/]	49.6%	0.0%	50.4%
Hamilton Utilities [1/]	38.7%	0.0%	61.3%
Hydro One Inc.	55.4%	2.2%	42.3%
Hydro Ottawa Holding Inc. [1/]	42.3%	0.0%	57.7%
London Hydro [1/]	45.7%	0.0%	54.3%
Maritime Electric	56.5%	0.0%	43.5%
Newfoundland Power	54.7%	1.0%	44.2%
Nova Scotia Power	57.9%	3.8%	38.3%
Ontario Power Generation	36.4%	0.0%	63.6%
Toronto Hydro	57.0%	0.0%	43.0%
Veridian Corp. [1/]	44.1%	0.0%	55.9%
Gas Distributors [2/]			
Enbridge Gas Distribution	57.3%	2.1%	40.5%
FortisBC Energy Inc.	59.7%	0.0%	40.3%
Gaz Métro L.P.	60.0%	0.0%	40.0%
Pacific Northern Gas [3/]	47.7%	2.6%	49.7%
Union Gas Limited	61.5%	2.5%	36.0%
Pipelines			
Enbridge Pipelines Inc.	51.8%	0.0%	48.2%
Nova Gas Transmission Ltd.	65.4%	0.0%	34.6%
Trans Québec & Maritimes Pipeline [1/]	60.0%	0.0%	40.0%
TransCanada PipeLines Ltd.	52.1%	0.9%	47.0%
Westcoast Energy Inc.	58.8%	3.6%	37.6%
Medians			
Electric Utilities	**54.7%**	**0.0%**	**45.0%**
Gas Distributors	**59.7%**	**2.1%**	**40.3%**
Pipelines	**58.8%**	**0.0%**	**40.0%**
All Companies	**55.4%**	**0.0%**	**43.5%**
All Investor Owned Companies	**57.4%**	**0.0%**	**40.5%**
All Investor Owned Companies (Excluding Nova Scotia Power)	**57.4%**	**0.0%**	**41.1%**

[1/] Capital structure from 2010.

[2/] The average of the four quarters ending December 2011 for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.

[3/] Capital structure is the average of the four quarters ending September 2011.

[4/] Includes preferred securities classified as debt.

[5/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

[6/] Includes non-controlling interests in common shares of subsidiary companies.

[7/] Previously Chatham-Kent Energy Inc.

Notes:

Financial statements for FortisBC Energy (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

Company	EBIT Coverage 2010	EBIT Coverage 2009	EBIT Coverage 2008	EBIT Coverage 3 Year Average		FFO Interest Coverage 2010	FFO Interest Coverage 2009	FFO Interest Coverage 2008	FFO Interest Coverage 3 Year Average		FFO To Debt 2010	FFO To Debt 2009	FFO To Debt 2008	FFO To Debt 3 Year Average	
Electric Utilities															
AltaLink L.P.	1.80	1.80	1.80	1.80		2.70	3.00	3.20	2.97		11.00	12.70	12.70	12.13	
CU Inc.	2.40	2.40	2.10	2.30		3.10	3.40	3.50	3.33		14.90	17.90	16.90	16.57	
Enersource	2.20	2.20	2.50	2.30		3.80	3.60	3.50	3.63		19.40	18.40	18.10	18.63	
ENMAX Corp.	1.90	2.30	2.70	2.30		3.10	3.30	3.80	3.40		13.70	13.60	13.70	13.67	
ENTEGRUS Inc. [6/]	4.00	3.70	3.50	3.73		5.50	5.40	5.50	5.47		29.70	29.50	34.90	31.37	
EPCOR Utilities Inc.	2.20	2.10	1.50	1.93		2.70	2.60	2.90	2.73		13.20	16.40	15.10	14.90	
FortisAlberta Inc.	2.00	2.10	2.00	2.03		3.90	3.80	3.80	3.83		13.90	13.20	12.50	13.20	
FortisBC Inc.	2.10	2.04	2.05	2.06	1/	3.00	2.90	2.80	2.90	2/	11.60	11.90	11.20	11.57	2/
Guelph Hydro Electric Systems	3.20	3.50	3.20	3.30		4.60	5.00	5.30	4.97		15.40	22.70	25.70	21.27	
Hamilton Utilities	3.10	3.30	3.30	3.23		5.20	4.60	5.10	4.97		27.00	29.60	35.30	30.63	
Hydro One Inc.	2.30	2.10	2.80	2.40		3.00	2.80	4.00	3.27		12.20	11.40	14.50	12.70	
Hydro Ottawa Holding Inc.	4.30	4.30	4.10	4.23		6.40	6.20	6.20	6.27		27.80	27.30	25.50	26.87	
London Hydro	3.10	3.30	2.90	3.10	3/	5.50	5.20	4.80	5.17	4/	25.60	27.50	26.20	26.43	3/
Maritime Electric	2.40	2.30	2.30	2.33		2.80	3.10	3.20	3.03		13.60	16.30	17.40	15.77	
Newfoundland Power	2.41	2.40	2.53	2.45	1/	3.40	3.10	3.00	3.17	2/	17.60	15.00	15.80	16.13	2/
Nova Scotia Power	1.80	2.20	2.40	2.13		3.40	3.00	3.10	3.17		14.60	14.50	15.90	15.00	
Ontario Power Generation	2.50	3.20	1.90	2.53	3/	2.80	2.60	3.40	2.93		10.10	9.60	13.80	11.17	
Toronto Hydro	1.80	1.60	1.80	1.73		3.60	3.30	3.40	3.43		16.00	16.30	17.50	16.60	
Veridian Corp.	3.49	3.59	3.16	3.41	1/	na	na	na	na		29.00	33.50	22.40	28.30	1/
Gas Distributors															
Enbridge Gas Distribution	2.30	2.40	2.30	2.33		3.40	3.50	3.30	3.40		16.30	18.10	16.30	16.90	
FortisBC Energy Inc.	2.10	1.90	1.90	1.97	1/	2.70	2.60	2.50	2.60	2/	10.60	10.20	9.80	10.20	2/
Gaz Métro L.P.	2.40	2.20	2.20	2.27	3/	4.50	4.50	4.60	4.53		21.00	22.80	22.10	21.97	
Pacific Northern Gas	2.49	2.59	2.13	2.40	1/	3.90	2.60	2.26	2.92	5/	19.60	11.70	11.20	14.17	1/
Union Gas Limited	2.60	2.40	2.40	2.47		3.50	2.90	3.42	3.27		16.50	14.80	15.10	15.47	
Pipelines															
Enbridge Pipelines Inc.	2.30	2.70	2.90	2.63		3.00	2.80	2.60	2.80		13.20	8.10	6.60	9.30	
NOVA Gas Transmission Ltd.	2.18	1.94	2.15	2.09	1/	na	na	na	na		14.30	14.20	14.20	14.23	1/
Trans Québec & Maritimes Pipeline	3.00	3.50	2.10	2.87		4.10	4.40	3.60	4.03		16.50	20.20	15.80	17.50	
TransCanada PipeLines Ltd.	1.80	1.90	2.30	2.00		2.90	2.80	3.00	2.90		11.90	12.40	13.00	12.43	
Westcoast Energy Inc.	2.60	2.40	2.70	2.57		3.50	2.90	3.50	3.30		15.80	13.30	17.90	15.67	
Medians															
Electric Utilities	**2.40**	**2.30**	**2.50**	**2.33**		**3.40**	**3.30**	**3.50**	**3.37**		**14.90**	**16.30**	**16.90**	**16.13**	
Gas Distributors	**2.40**	**2.40**	**2.20**	**2.33**		**3.50**	**2.90**	**3.30**	**3.27**		**16.50**	**14.80**	**15.10**	**15.47**	
Pipelines	**2.30**	**2.40**	**2.30**	**2.57**		**3.25**	**2.85**	**3.25**	**3.10**		**14.30**	**13.30**	**14.20**	**14.23**	
All Companies	**2.40**	**2.40**	**2.30**	**2.33**		**3.40**	**3.10**	**3.42**	**3.30**		**15.40**	**15.00**	**15.80**	**15.67**	
All Investor Owned Companies	**2.30**	**2.30**	**2.20**	**2.30**		**3.40**	**3.00**	**3.20**	**3.17**		**14.60**	**14.20**	**15.10**	**15.00**	
All Investor Owned Companies (Excluding Nova Scotia Power)	**2.35**	**2.35**	**2.18**	**2.32**		**3.40**	**3.00**	**3.20**	**3.17**		**14.60**	**13.75**	**14.65**	**14.85**	

[1/] Data from DBRS.
[2/] Data from Moody's.
[3/] 2010 data from S&P Credit Stats.
[4/] 2010 data ending September 2010.
[5/] Calculated from Annual Reports.
[6/] Previously Chatham-Kent Energy Inc.
Source: Standard & Poor's Debt Rating Reports except where noted.

CREDIT METRICS OF U.S. UTILITIES

Company	EBIT Coverage 2010	EBIT Coverage 2009	EBIT Coverage 2008	EBIT Coverage 3 Year Average	FFO Interest Coverage 2010	FFO Interest Coverage 2009	FFO Interest Coverage 2008	FFO Interest Coverage 3 Year Average	FFO To Debt 2010	FFO To Debt 2009	FFO To Debt 2008	FFO To Debt 3 Year Average
ALLETE Inc.	3.60	3.30	4.10	3.67	5.70	5.50	5.20	5.47	21.70	20.00	17.60	19.77
Alliant Energy Corp.	3.30	2.60	3.20	3.03	5.30	4.50	4.50	4.77	24.80	22.70	20.00	22.50
Avista Corp.	3.00	3.00	2.40	2.80	4.20	4.30	4.00	4.17	18.20	19.80	18.50	18.83
Dominion Resources	3.60	3.20	3.50	3.43	3.10	4.80	4.00	3.97	12.20	22.20	17.10	17.17
IDACORP Inc.	2.40	2.60	2.20	2.40	3.80	4.00	2.90	3.57	14.80	16.70	10.30	13.93
Integrys Energy Group Inc.	3.70	3.10	2.00	2.93	5.70	5.50	5.20	5.47	25.20	25.50	18.20	22.97
MGE Energy Inc. [1/]	5.30	4.40	4.90	4.87	6.60	5.00	6.50	6.03	28.10	24.70	25.20	26.00
NextEra Energy Inc.	4.40	3.50	3.50	3.80	6.30	7.30	5.80	6.47	23.80	29.50	23.10	25.47
OGE Energy Corp.	4.40	3.70	3.70	3.93	5.00	6.70	6.60	6.10	20.90	31.40	25.40	25.90
Sempra Energy	2.00	3.80	3.50	3.10	4.40	4.20	3.90	4.17	20.40	18.60	15.80	18.27
Southern Company	3.60	3.20	3.30	3.37	4.90	4.40	4.20	4.50	20.10	18.10	17.20	18.47
Vectren Corp.	2.90	2.90	3.10	2.97	5.40	5.00	5.10	5.17	25.50	21.40	21.20	22.70
Westar Energy	2.60	2.20	2.20	2.33	4.20	3.40	3.60	3.73	19.20	14.30	12.60	15.37
Wisconsin Energy Corp.	2.80	2.20	1.10	2.03	4.80	4.70	5.00	4.83	18.40	16.70	18.40	17.83
Xcel Energy Inc.	2.90	2.70	2.50	2.70	4.40	4.20	3.90	4.17	19.00	18.80	17.10	18.30
Medians												
All Companies	**3.30**	**3.10**	**3.20**	**3.03**	**4.90**	**4.70**	**4.50**	**4.77**	**20.40**	**20.00**	**18.20**	**18.83**

[1/] Data for Madison Gas % Electric Co.

Source: Standard & Poor's Debt Rating Reports except where noted.

Schedule 5

EQUITY RETURN AWARDS AND COMMON EQUITY RATIOS
ADOPTED FOR THE SAMPLE OF U.S. ELECTRIC UTILITIES
2009-2012

Parent	Subsidiary	State	Decision Date	Allowed ROE	Allowed Common Equity Ratio	
Allete Inc.	Minnesota Power	MN	11/2/2010	10.38	54.29	
Allete Inc.	Superior Water, Light & Power	WI	12/1/2010	10.90	54.90	
Alliant Energy Corp.	Interstate P&L	IA	12/15/2010	10.44	44.24	
Alliant Energy Corp.	Interstate P&L	MN	8/12/2011	10.35	47.74	
Alliant Energy Corp.	Wisconsin P&L	WI	12/18/2009	10.40	50.38	
Avista Corp.	Avista Corp.	ID	9/21/2010	9.90	46.50	
Avista Corp.	Avista Corp.	WA	11/19/2010	10.20	47.94	
Dominion Resources	Virginia Electric & Power	NC	12/13/2010	10.70	51.00	
Dominion Resources	Virginia Electric & Power	VA	3/23/2012	10.40	53.25	a/
IDACORP Inc.	Idaho Power Company	ID	12/30/2011	10.50	49.27	
IDACORP Inc.	Idaho Power Company	OR	2/23/2012	9.90	49.90	
Integrys Energy Group Inc.	Upper Peninsula Power	MI	12/20/2011	10.20	54.90	
Integrys Energy Group Inc.	Wisconsin Public Service	WI	1/13/2011	10.30	51.65	
MGE Energy Inc.	Madison G&E	WI	1/12/2011	10.30	58.06	
Next Era Energy Inc.	Florida Power & Light Co.	FL	3/17/2010	10.00	59.10	
OGE Energy Corp.	Oklahoma G&E	AR	6/17/2011	9.95	46.00	
Southern Co.	Gulf Power Co.	FL	2/27/2012	10.25	46.26	
Southern Co.	Georgia Power	GA	12/29/2010	11.15	51.67	
Vectren Corp.	Southern Indiana G&E	IN	4/27/2011	10.40	49.93	
Westar Energy	Westar Energy Inc.	KS	4/18/2012	NA	NA	b/
Wisconsin Energy Corp.	Wisconsin Electric Power	MI	7/1/2010	10.25	52.48	
Wisconsin Energy Corp.	Wisconsin Electric Power	WI	12/18/2009	10.40	53.02	
Xcel Energy Inc.	Public Service of CO	CO	12/3/2009	10.50	58.56	
Xcel Energy Inc.	Northern States Power-MN	MN	3/29/2012	10.37	52.56	
Xcel Energy Inc.	Northern States Power-MN	ND	2/29/2012	10.40	51.77	
Xcel Energy Inc.	Southwestern Public Service	TX	3/25/2011	NA	NA	c/
Xcel Energy Inc.	Northern States Power-WI	WI	12/22/2011	10.40	52.59	
2009-2012:						
Mean				**10.36**	**51.52**	
Median				**10.38**	**51.67**	
2011-2012:						
Mean				**10.29**	**51.07**	
Median				**10.35**	**51.65**	

a/ Allowed ROE is base return excluding 100 basis point plant-specific premium.
b/ Westar is authorized to calculate its rate of return for regulatory accounting purposes with an assumed ROE of 10.0% and 52.629% equity ratio until Westar's next general rate proceeding.
c/ A 10% ROE and 51% equity ratio are to be used, per the settlement, solely for purposes of any Transmission Cost Recovery Factor filings before the next PUC rate case and for AFUDC purposes only, the ROE will be 10%.

Source: Regulatory Research Associates and various regulatory decisions.

Schedule 6

INDIVIDUAL COMPANY DATA FOR SAMPLE OF U.S. UTILITIES

	Value Line							S & P			Moody's
	Safety	Forecast Common Equity Ratio 2015-2017 [1/]	Forecast Return On Average Common Equity 2015-2017	Dividend Payout Forecast 2015-2017	2012 Q1 Beta	Common Equity Ratio 4Q2011 (Trailing Four Quarters)	2007-2011 Average Earned Returns	Business Risk Profile	Financial Risk Profile	Debt Rating [2/]	Debt Rating [3/]
ALLETE Inc.	2	60.0%	9.6%	61.5%	0.70	55.9%	9.4%	Strong	Significant	BBB+	Baa1
Alliant Energy Corp.	2	49.5%	11.4%	61.1%	0.75	50.1%	10.2%	Excellent	Significant	BBB+	Baa1
Avista Corp.	2	48.0%	8.9%	70.0%	0.70	48.3%	7.5%	Excellent	Aggressive	BBB	Baa2
Dominion Resources	2	43.5%	15.1%	65.0%	0.70	37.4%	18.3%	Excellent	Significant	A-	Baa2
IDACORP Inc.	3	53.5%	8.2%	55.4%	0.70	50.9%	8.9%	Excellent	Aggressive	BBB	Baa2
Integrys Energy Group Inc.	2	56.0%	9.8%	65.9%	0.90	55.2%	5.5%	Excellent	Significant	A-	Baa1
MGE Energy Inc.	1	62.0%	10.7%	58.4%	0.60	59.9%	11.4%	Excellent	Intermediate	AA-	A1
NextEra Energy Inc.	2	46.5%	12.3%	47.0%	0.75	40.2%	13.6%	Strong	Intermediate	A-	Baa1
OGE Energy Corp.	2	49.5%	11.9%	44.7%	0.80	48.3%	13.7%	Strong	Significant	BBB+	Baa1
Sempra Energy	2	51.5%	11.2%	43.5%	0.80	48.5%	12.7%	Strong	Intermediate	BBB+	Baa1
Southern Company	1	45.5%	12.6%	69.2%	0.55	44.3%	13.1%	Excellent	Intermediate	A	Baa1
Vectren Corp.	2	48.0%	12.2%	64.0%	0.70	45.2%	10.1%	Excellent	Significant	A-	A3
Westar Energy	2	49.5%	8.7%	61.7%	0.75	44.7%	8.9%	Excellent	Aggressive	BBB	Baa2
Wisconsin Energy Corp.	1	46.5%	13.9%	65.5%	0.65	43.5%	11.9%	Excellent	Significant	A-	A3
Xcel Energy Inc.	2	49.0%	9.8%	65.0%	0.65	45.3%	9.7%	Excellent	Significant	A-	Baa1
Mean	**2**	**50.6%**	**11.1%**	**59.9%**	**0.71**	**47.9%**	**11.0%**	**Excellent**	**Significant**	**A-**	**Baa1**
Median	**2**	**49.5%**	**11.2%**	**61.7%**	**0.70**	**48.3%**	**10.2%**	**Excellent**	**Significant**	**A-**	**Baa1**

[1/] Based on permanent capital.

[2/] Rating for MGE Energy Inc. is for Madison Gas & Electric Co.

[3/] Rating for MGE Energy Inc. is for Madison Gas & Electric Co. Rating for Vectren Corp. is for Vectren Utility Holdings.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (January 5, 2012); Standard and Poor's, *Issuer Ranking: U.S. Regulated Natural Gas Utilities, Strongest To Weakest* (January 11, 2012); Standard and Poor's *Research Insight*; *Value Line* (February and March 2012); *Value Line Index*, March 23, 2012; and www.yahoo.com.

DCF COST OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

				Analyst Forecast Long-Term Growth Rates					
Company	Annualized Last Paid Dividend	Average Daily Close Prices 12/16/2011-3/15/2012	Expected Dividend Yield [1/]	Bloomberg	Reuters	Value Line	Zacks	Average of All EPS Estimates	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ALLETE Inc.	1.84	41.38	4.7	6.3	6.5	6.5	5.0	6.1	10.8
Alliant Energy Corp.	1.80	43.07	4.4	5.8	5.3	6.5	6.0	5.9	10.3
Avista Corp.	1.16	25.39	4.8	4.7	4.5	4.5	4.7	4.6	9.4
Dominion Resources	2.11	50.96	4.3	3.5	5.2	5.0	5.5	4.8	9.1
IDACORP Inc.	1.32	41.54	3.3	4.5	4.7	4.0	5.0	4.5	7.9
Integrys Energy Group Inc.	2.72	52.96	5.5	4.5	9.5	7.0	4.5	6.4	11.8
MGE Energy Inc.	1.53	45.34	3.5	4.0	4.0	4.0	4.0	4.0	7.5
NextEra Energy Inc.	2.40	59.83	4.2	5.0	5.7	4.5	6.4	5.4	9.6
OGE Energy Corp.	1.57	54.00	3.1	6.3	6.8	6.0	5.9	6.2	9.3
Sempra Energy	1.92	56.93	3.6	8.0	6.7	4.5	7.0	6.6	10.1
Southern Company	1.89	44.93	4.4	6.0	5.8	5.0	5.0	5.4	9.9
Vectren Corp.	1.40	29.32	5.0	5.5	5.5	6.5	4.3	5.5	10.5
Westar Energy	1.32	28.19	4.9	4.9	5.0	6.5	NA	5.5	10.4
Wisconsin Energy Corp.	1.20	34.43	3.7	6.5	7.2	6.5	6.3	6.6	10.3
Xcel Energy Inc.	1.04	26.75	4.1	5.3	5.1	5.0	5.1	5.1	9.2
Mean	**1.68**	**42.33**	**4.2**	**5.4**	**5.8**	**5.5**	**5.3**	**5.5**	**9.7**
Median	**1.57**	**43.07**	**4.3**	**5.3**	**5.5**	**5.0**	**5.1**	**5.5**	**9.9**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
[2/] Expected Dividend Yield (Col (3)) + Average of All EPS Estimates (Col (8))

Source: Bloomberg, www.reuters.com, Value Line (February and March 2012), www.yahoo.com, and www.zacks.com.

Schedule 8

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 12/16/2011-3/15/2012	Expected Dividend Yield [1/]	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth [2/] (1st Qtr.2012)	SV Growth [3/] (1st Qtr. 2012)	Sustainable Growth [4/] (1st Qtr. 2012)	DCF Cost of Equity [5/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ALLETE Inc.	1.84	41.38	4.6	9.6	38.5	3.7	0.29	4.0	8.6
Alliant Energy Corp.	1.80	43.07	4.4	11.4	38.9	4.4	0.28	4.7	9.1
Avista Corp.	1.16	25.39	4.7	8.9	30.0	2.7	0.32	3.0	7.7
Dominion Resources	2.11	50.96	4.4	15.1	35.0	5.3	0.44	5.7	10.1
IDACORP Inc.	1.32	41.54	3.3	8.2	44.6	3.6	0.03	3.7	7.0
Integrys Energy Group Inc.	2.72	52.96	5.3	9.8	34.1	3.3	0.00	3.3	8.6
MGE Energy Inc.	1.53	45.34	3.5	10.7	41.6	4.5	0.12	4.6	8.1
NextEra Energy Inc.	2.40	59.83	4.3	12.3	53.0	6.5	-0.05	6.5	10.7
OGE Energy Corp.	1.57	54.00	3.1	11.9	55.3	6.6	0.16	6.8	9.9
Sempra Energy	1.92	56.93	3.6	11.2	56.5	6.3	0.11	6.4	10.0
Southern Company	1.89	44.93	4.4	12.6	30.8	3.9	0.72	4.6	9.0
Vectren Corp.	1.40	29.32	5.0	12.2	36.0	4.4	0.64	5.0	10.0
Westar Energy	1.32	28.19	4.8	8.7	38.3	3.3	0.09	3.4	8.3
Wisconsin Energy Corp.	1.20	34.43	3.6	13.9	34.5	4.8	-0.33	4.5	8.1
Xcel Energy Inc.	1.04	26.75	4.0	9.8	35.0	3.4	0.32	3.8	7.8
Mean	**1.68**	**42.33**	**4.21**	**11.08**	**40.15**	**4.45**	**0.21**	**4.7**	**8.9**
Median	**1.57**	**43.07**	**4.38**	**11.19**	**38.33**	**4.38**	**0.16**	**4.6**	**8.6**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
[2/] BR Growth = Col (4) * (Col (5) / 100)
[3/] SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M].
[4/] Col (6) + Col (7)
[5/] Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: *Value Line* (January and February 2012) and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 12/16/2011-3/15/2012	Growth Rates: Stage 1: Average of All EPS Forecasts	Growth Rates: Stage 2: Average of Stage 1 & 3	Growth Rates: Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)
ALLETE Inc.	1.84	41.38	6.1	5.5	4.9	9.9
Alliant Energy Corp.	1.80	43.07	5.9	5.4	4.9	9.5
Avista Corp.	1.16	25.39	4.6	4.7	4.9	9.5
Dominion Resources	2.11	50.96	4.8	4.8	4.9	9.1
IDACORP Inc.	1.32	41.54	4.5	4.7	4.9	8.0
Integrys Energy Group Inc.	2.72	52.96	6.4	5.6	4.9	10.7
MGE Energy Inc.	1.53	45.34	4.0	4.5	4.9	8.1
NextEra Energy Inc.	2.40	59.83	5.4	5.2	4.9	9.2
OGE Energy Corp.	1.57	54.00	6.2	5.6	4.9	8.1
Sempra Energy	1.92	56.93	6.6	5.7	4.9	8.7
Southern Company	1.89	44.93	5.4	5.2	4.9	9.4
Vectren Corp.	1.40	29.32	5.5	5.2	4.9	10.0
Westar Energy	1.32	28.19	5.5	5.2	4.9	9.9
Wisconsin Energy Corp.	1.20	34.43	6.6	5.8	4.9	8.9
Xcel Energy Inc.	1.04	26.75	5.1	5.0	4.9	8.9
Mean	**1.68**	**42.33**	**5.5**	**5.2**	**4.9**	**9.2**
Median	**1.57**	**43.07**	**5.5**	**5.2**	**4.9**	**9.2**

[1/] Forecast nominal rate of GDP growth, 2014-23
[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Bloomberg, Blue Chip *Economic Indicators* (March 2012), www.reuters.com,
Value Line (January and February 2012), www.yahoo.com, and www.zacks.com.

MARKET VALUE CAPITAL STRUCTURES FOR U.S. UTILITIES SAMPLE

	Debt and Preferred Shares at Par (Millions $, December 2011)	Common Share Price Average Daily Close 12/16/2011-3/15/2012	Common Shares Outstanding (Millions, December 2011)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
ALLETE Inc.	864	41.38	38	1,552	64.2%
Alliant Energy Corp.	3,012	43.07	111	4,782	61.3%
Avista Corp.	1,325	25.39	58	1,469	52.6%
Dominion Resources	20,944	50.96	570	29,047	58.1%
IDACORP Inc.	1,543	41.54	50	2,075	57.4%
Integrys Energy Group Inc.	2,476	52.96	78	4,126	62.5%
MGE Energy Inc.	364	45.34	23	1,048	74.2%
NextEra Energy Inc.	22,967	59.83	423	25,280	52.4%
OGE Energy Corp.	3,014	54.00	98	5,297	63.7%
Sempra Energy	10,962	56.93	240	13,663	55.5%
Southern Company	22,305	44.93	865	38,870	63.5%
Vectren Corp.	1,849	29.32	82	2,401	56.5%
Westar Energy	3,126	28.19	126	3,543	53.1%
Wisconsin Energy Corp.	5,347	34.43	231	7,963	59.8%
Xcel Energy Inc.	10,127	26.75	486	13,014	56.2%
Mean				**$10,275**	**59.4%**
Median				**$4,782**	**58.1%**

Source: Reports to Shareholders, Standard and Poor's Research Insight, www.yahoo.com

IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY:

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases,

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.35%
Equity Cost	=	8.75%
Tax Rate	=	31.0%
CEQ Ratio	Step (1)	45.0%
Debt Ratio	Step (1)	55.0%
CEQ Ratio	Step (2)	37.5%
Debt Ratio	Step (2)	62.5%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sa (common equity ratio of 45.0%)

   $WACC_{AT}$ = (5.35%)(1-.310)(55.0%) + (8.75%)(45.0%)
   = 5.97%

2. Estimate Cost of Equity for sample at 37.5% common equity ratic $WACC_{AT}$ unchanged at 5.97%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   5.97% = (5.35%)(1-.310)(62.5%) + (X)(37.5%)
   Cost of Equity at 37.5% Equity Ratio = 9.76%

3. Difference between Equity Return at 45.0% and 37.5% common equity ratios:
   9.76% - 8.75% = 1.01% (101 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.35%
Equity Cost	=	8.75%
Tax Rate	=	31.0%
CEQ Ratio	Step (1)	45.0%
Debt Ratio	Step (1)	55.0%
CEQ Ratio	Step (2)	37.5%
Debt Ratio	Step (2)	62.5%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 45.0%)

$$WACC_{AT} = (5.35\%)(1-.310)(55.0\%) + (8.75\%)(45.0\%)$$
$$= 5.97\%$$

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 37.5%)

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1-t \times \text{Debt Ratio}_{ML})/(1-t \times \text{Debt Ratio}_{LL})$$

$$WACC_{AT(ML)} = 5.97\% \times \frac{(1-.310 \times 62.5\%)}{(1-.310 \times 55.0\%)}$$

$$WACC_{AT(ML)} = 5.80\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$$WACC_{AT(ML)} = (\text{Debt Cost})(1\text{-tax rate})(\text{Debt Ratio}_{ML}) + (\text{Equity Cost})(\text{Equity Ratio}_{ML})$$

5.80% = (5.35%)(1-.310)(62.5%) + (X)(37.5%)
Cost of Equity at 37.5% Equity Ratio = 9.32%

4. Difference between Equity Return at 45.0% and 37.5% common equity ratios:

9.32% - 8.75% = 0.57% (57 basis points)

Nova Scotia Utility and Review Board

Nova Scotia Power Incorporated

2013 and 2014

UNMETERED SERVICES
COST OF SERVICE AND PRICING STUDY REVIEW

May 8, 2012

Nova Scotia Power Incorporated
Unmetered Services Cost of Service and Pricing Study Review

Table of Contents

1 INTRODUCTION

This report is filed in support of NS Power's General Rate Application (GRA). The report provides a description of unmetered services, followed by an outline of the current ratemaking methodology which is then followed by a detailed discussion of the calculations of streetlight rates.

1.1 Unmetered Services at NS Power in General

The Unmetered Class includes three distinct service categories:

- electric service only, applicable to both streetlight and miscellaneous loads
- electric service combined with streetlight fixture maintenance
- full streetlight service, which includes electric service, maintenance and capital costs associated with streetlight fixtures

What these services have in common is their eligibility for unmetered service, based on the impracticality of metering their loads. Either costs of metering these loads, which include both capital meter costs and meter reading operational costs, are prohibitively high relative to the value of energy consumed or the loads are highly predictable.

All service categories involve consumption of electricity, the costs of which are shared with all metered classes. The fixture maintenance costs have a significant direct cost component. The capital costs of fixtures are treated as a direct responsibility of the unmetered class and are not shared with other rate classes. Streetlight customers have a choice of maintenance service providers and fixture ownership.

Consistent with the three types of streetlight services, there are three distinct types of streetlight charges. The streetlight rate reflective of all three services combined is referred to as a full charge rate. Where the customer owns the fixture and NS Power performs the maintenance, applicable rates include the power and energy and maintenance charges. For situations where the customer owns and maintains the fixture, only power and energy charges are applied.

The miscellaneous load services are electric only and are billed under a few hundred customized rates.

2 RATEMAKING METHODOLOGY FOR UNMETERED SERVICES

In its 2012 GRA Decision, the Board approved the following methodological changes to the ratemaking treatment of unmetered services.

- A new service category of Light-Emitting Diode (LED) streetlights was placed outside of COSS as a below-the-line item. Its rate base and costs are treated as direct capital and direct expense items, respectively in COSS.

- A new category of stranded costs associated with early retired non-LED is also treated as direct capital and direct expense items in COSS.

- The depreciation costs of streetlight fixtures, as available from NS Power's financial information systems are applied directly for costing and pricing purposes.

- The pricing of unmetered service components of energy, fixture maintenance and fixture capital is to be aligned with costs in two phases. The first phase of alignment took place in 2012 and the second phase was postponed until the next rate case after the 2012 GRA.

- The determination of the value associated with the non-LED stranded asset was deferred until a LED capital work order is submitted.

- The prices of full LED streetlight services will be updated at the time of a LED capital work order submission.

The ratemaking methodology currently in place is comprised of three distinct steps:

1. determination of cost responsibilities of LED customers for LED fixture capital and early retired non-LED fixtures, done outside of COSS

2. determination of cost responsibilities of the COSS-based unmetered class, which is comprised of all costs of non-LED fixtures, and electric service costs of LED streetlights and miscellaneous loads

3. determination of revenue responsibilities of each service category by setting them at costs, as determined above, followed by individual service rate calculations as based on usage

2.1 Cost of Service Studies (COSS)

From a broad cost treatment perspective, costs of unmetered services can be categorized as those shared with other COSS classes and those assigned directly to the unmetered class.

Most of electric service costs are shared with metered classes and are assigned to the unmetered class using a three step costing process consisting of functionalization, classification and allocation. The cost responsibilities of the Unmetered Class are determined, as is the case with other classes, based on its cost causation and utilization of the electric infrastructure.

The fixture maintenance-related costs are made up of costs assigned directly to this class and costs shared with other classes.

The streetlight fixture capital related costs such as taxes, depreciation, interest and cost of equity are considered a direct responsibility of the streetlight customers. However, the cost information for the above categories, with the exception of depreciation, is only available in aggregate for the company as a whole. Consequently, customer responsibilities for these costs cannot be determined by direct assignment. The capital costs associated with non-LED fixtures are determined using the COSS-based cost allocation methodology. The capital costs associated with non-LED fixtures are determined using the tax adjusted weighted average cost of capital (WACC).

2.2 Pricing of Unmetered Services

The Street/crosswalk Lighting Study contained below in Section 3.0, focuses on determining capital and maintenance costs and is generally conducted independently of the Company's Cost of Service Study. Starting with this submission revenue responsibilities for services of electricity, fixture maintenance, and fixture capital are aligned with costs of these services.

2.2.1 Determination of Electric Service Rates

The unmetered rates for electricity are determined by employing a rate design approach consisting of applying miscellaneous lighting and miscellaneous small load rates to the pre-determined patterns and levels of energy consumption. The rate structure includes one demand charge and two declining energy charges, applicable to energy blocks whose sizes vary with metered demand.[1] The rates are changed only through GRA proceedings; however they can be, and are, used by NS Power to develop unpublished energy-only rates for miscellaneous loads without specific approval by the Board. In contrast, the published streetlight rates are always approved by the Board.

[1] This rate structure is commonly known as hours'-use or Wright demand rate and is also in effect for General and Small Industrial Rate classes.

3 STREET / CROSSWALK LIGHTING STUDY

Street and Crosswalk lighting represent 90 percent of the total number of NS Power's unmetered service units and the total revenue collected from customers.

In conducting this 2013 and 2014 update, the following information was reviewed, updated and added:

- Schedule 1 – Street and Crosswalk Lighting Inventory Levels: actual and forecast
- Schedule 2 – Determination of Maintenance Costs by Fixture Type
- Schedule 3 – Determination of Average Installation Labour Costs associated with Streetlighting Gross Assets
- Schedule 4 – Determination of Depreciation and Capital-related costs by Fixture Type
- Schedule 5 – Tax-Adjusted Weighted Average Cost of Capital (WACC)
- Schedule 5A – Capital Cost Expenses calculated with WACC
- Schedule 6 & 7 – Summary and Detail of Current Material Costs by Fixture Type
- Schedule 8 – Lamp Life Analysis
- Schedule 9 – CCA Benefit Schedule
- Schedule 10 – Updated Street and Crosswalk Lighting Rates by Cost Component and Total Revenue based on forecast Inventory levels

3.1 Schedule 1 - Street and Crosswalk Lighting Inventory: Actual and Forecast

The lighting units used for the purpose of 2013 and 2014 test year rate calculations were forecast using actual inventory levels as of March 2011, and adjusted for recent changes by municipalities to energy only lights, and forecast capital spend on non-LED and LED units in 2013 and 2014. To reflect fixture counts accurately in rate calculations, average annual counts (average of year-beginning and year-end figures) were used as opposed to year-end figures. This is appropriate because step changes in the counts of many of the non-LED fixtures are anticipated as a result of their replacement with LED fixtures in 2013 and 2014.

The total average number of non-LED units in 2013 and 2014 are 114,783 and 95,282, respectively. In 2013, the total is made up of 103,386 full charge lights, 957 power and maintenance, and 10,440 energy only. In 2014, the total is made up of 83,885 full charge lights, 10,440 power-only lights, and 957 power and maintenance lights.

The projected total average LED units in 2013 and 2014 are 24,274 and 43,774, respectively. In 2013, the total is made up of 16,663 full charge lights, and 7,611 power-only lights. In 2014, the total is made up of 36,163 full charge lights and 7,611 power-only lights. There is no LED rate category proposed for the combined power and maintenance services. The High Pressure (Intensity) Sodium lights are forecast to account for the majority of the lights (69 percent in 2013 and 57 percent in 2014) in NS Power's system. This will change, however, in the next few years as LED deployment will come to displace most of the non-LED technology.

3.2 Schedule 2 - Determination of Maintenance Costs by Fixture Type

The purpose of this schedule is to assign current maintenance costs to all lights containing a maintenance charge, based on the service life of each lamp type and the associated maintenance weighting factors, as measured relative to the replacement of 100W High Pressure (Intensity) Sodium lights. These weighting factors and all maintenance-charged lights are used to determine the weighted total number of lights maintained (column F). Current streetlight operating expenses are used to determine annual and monthly maintenance costs by fixture type. The operating expenses used in this review are based on forecast streetlight expenses from Customer Operations for 2013 and 2014, including a share of corporate overhead and pension costs. The amounts of

$5.7 million in 2013 and $5.8 million in 2014 are identified in Exhibits 6A of the 2013 COSS and 2014 COSS. The results, using the forecast weighted number of streetlights and the forecast operating expenses for streetlights, are used to determine the annual and monthly maintenance charge to be applied to each type of light. At this time, there are no maintenance costs associated with LED streetlights.

3.3 Schedule 3 - Determination of Average Installation Labour Costs Associated with Streetlighting Gross Assets

The installation costs for non-LED fixtures are determined using the current approved methodology, which is predicated on forecast gross plant value, number of fixtures and the most recent fixture market replacement value.

This schedule uses the average gross plant value of Streetlight assets of $43.8 million forecast for 2013 and $35.5 million in 2014 and the current material costs of each type of fixture, along with the forecast average number of fixtures for both years, to arrive at a total installation labour cost. The current material cost of each fixture is multiplied by the number of forecast fixtures to arrive at a total material capital cost. The amount is subtracted from the forecast total streetlight gross plant value to arrive at a total installation cost which, divided by the number of fixtures, results in an average installation labour cost of $188.13 in 2013 and $171.83 in 2014 per fixture. Material cost information for incandescent and fluorescent lighting was not available and therefore an estimated escalation factor of 125 percent was applied to the unit costs from 1977. This schedule includes a sample material cost breakdown of a 100W High Pressure (Intensity) Sodium light, which is re-produced below.

Sample Material Cost 100 Watt High Intensity (Pressure) Sodium	
Inventory Prices as of March 2011	
	2013 and 2014
Fixture, Ballast & Photocell	$124.02
Bracket Assembly (Davit)	$67.32
Wire	$16.71
Miscellaneous Hardware	$2.60
Lamp Replacement	$8.62
Total	$219.27

The installation costs for LED fixtures are determined using marginal cost methodology predicated on incremental costs of installation, reflective of economies of scale inherent in a massive LED deployment. Consistent with the Energy Efficient Appliances Regulations[2], currently undergoing public consultations, NS Power will complete installation of LED fixtures throughout the province by 2019 as contemplated by the draft regulations, working its way area by area, and thereby economizing on labour and transportation costs. The LED installation cost is estimated to be $136.78 (before Administrative Overhead) per fixture.

3.4 Schedule 4 - Determination of Depreciation and Capital-related Costs by Fixture Type

Schedule 4 illustrates the determination of capital costs and rates for non-LED and LED fixtures, respectively. As per the Depreciation Settlement, the depreciation rate used for 2013 and 2014 is 5.33 percent.[3] The tax-adjusted WACC for non-LED is 10.40 percent and LED is 9.31 percent in 2013 and 10.47 percent and 9.38 percent in 2014, respectively. The difference is due to the exclusion of ‘grants in lieu of taxes’ in the LED calculation. The tax-adjusted WACC is used to calculate the remaining capital-related costs such as interest, preferred dividends, income taxes, and net income for both LED and non-LED pricing purposes.

[2] Draft Energy Efficient Appliance Regulations: http://www.gov.ns.ca/energy/publications/Draft-LED-Regulations-2012-tracked-changes_2.pdf
[3] NS Power Depreciation Study Application, NSUARB-NSPI-P-891, UARB Order, May 11, 2011.

The non-depreciation capital costs of non-LED and LED fixtures are determined using a two-step process. As is the case under the current approved methodology, the tax-adjusted WACC is multiplied by the gross plant value of each fixture type to arrive at its marginal cost of capital. Next, by multiplying fixtures' marginal cost of capital by their inventory count and then aggregating them, NS Power arrives at the preliminary revenue amount. This figure, based upon fixtures' gross plant values, exceeds the cost of capital which is determined by the net plant values of LED and non-LED assets. In order to align the revenue responsibility of the streetlight customers for their streetlight capital costs, the marginal capital costs of each fixture are scaled down using the appropriate cost-based correction factors. To align revenues of non-LED fixtures, a COSS-based benchmark is used. For the LED cost benchmark calculation purposes, a tax adjusted WACC is applied to the asset net plant value.

3.5 Schedules 5 and 5A - Tax-Adjusted Weighted Average Cost of Capital

The tax adjusted WACC calculation is shown in Schedule 5. It is broken down into four components; pre-tax WACC, additional income tax on Common Equity, Large Corporation Tax and Grants-in-Lieu of Property Taxes (excluded from LED calculation). This results in a tax-adjusted WACC of 10.40 percent and 9.31 percent for non-LED and LED streetlights in 2013 and 10.47 percent and 9.38 percent in 2014, respectively.

Schedule 5A shows how tax-adjusted WACC components are used to determine total capital cost.

3.6 Schedules 6 and 7 - Summary and Detail of Streetlight Material Costs by Fixture Type

An analysis of current material costs was conducted using information as of March 2011, and adjusted for recent changes by municipalities. This analysis involved the review of all components used in the installation of streetlight fixtures such as the lamp, photocell, davit, wire, connectors and fasteners. In addition, NS Power has provided a detailed listing of all material costs obtained from the material inventory control system.

3.7 Schedule 8 - Lamp Life Analysis

Average Rated Life Spans of each lamp type, as provided in the Canadian Electrical Association's Lighting Reference Guide[4], were used in this study. Annual photocell cumulative operating time is based on 4000 hours per year or 333 hours per month. Using the average lamp life and burning hours per year, results in the expected service life, in years, by lamp type. The lamp life and number of replacements, relative to those of a 100W High Pressure (Intensity) Sodium lamp, are then determined. The results of this analysis are used to determine the frequency of bulb replacements as it pertains to annual maintenance work in Schedule 2. This analysis does not concern LED lights.

3.8 Schedule 9 – Capital Cost Allowance (CCA) Calculation

Schedule 9 illustrates the capital cost allowance (CCA) tax savings related to the LED streetlight investment. The capital investment in 2013 and 2014, being \$16.9 million and \$17.3 million, is multiplied by the CCA rate. For LED streetlight purposes, the rate is 8

[4] Product Knowledge – Lighting Reference Guide, Canadian Electrical Association, April 1992, originally printed by Ontario Hydro (4th Edition) 1991.

percent.[5] In the first year, only half of the CCA rate can be claimed. For 2013, this results in tax savings of $0.2 million and in 2014 it is $0.6 million.

3.9 Schedule 10 - New Street and Crosswalk Lighting Rates by Cost Component

Once the analysis of all costs components is complete, the results are summarized in Schedule 10 including the rate description, the rate code, the calculated monthly kWh usage, and the new power and energy, maintenance, and capital cost components. Incandescent rates < 300W and > 300W were set at those used for 250W and 400W Mercury Vapour rates, respectively. Calculation of the power and energy component is shown at the bottom of Schedule 10 and is based on annual photocell and continuous burning energy usage to arrive at average cents/kWh that is applied to the standard energy usage. In addition, this schedule compares the new resulting rates for 2013 and 2014 and the percentage increase/decrease from the current approved rates for 2013 and 2014. This results in total Street and Crosswalk Lighting Revenue of $23.6 million for 2013, and $25.1 million for 2014.

[5] Determined by Canada Revenue Agency: http://www.cra-arc.gc.ca/tx/bsnss/tpcs/slprtnr/rprtng/cptl/clsss-eng.html

Street / Crosswalk Lighting Study

2013 Schedules

SCHEDULE 1

2013 STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of MARCH 2011

		MARCH 2011 Adjusted (Quantity)				FORECAST 2013 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
001/003	Incandescent < 300 Watts	27	0	7	34	27	0	7	34	27
002	Incandescent > 300 Watts	2	0	0	2	2	0	0	2	2
		29	0	7	36	29	0	7	36	29
100	Mercury Vapour 100 Watts	251	0	0	251	251	0	0	251	234
101/201/301	Mercury Vapour 125 Watts	10,349	7	11	10,367	10349	7	11	10367	9635
102/202/302	Mercury Vapour 175 Watts	2,474	21	157	2,652	2474	21	157	2652	2303
103/203/303	Mercury Vapour 250 Watts	953	35	54	1,042	953	35	54	1042	887
104/204/304	Mercury Vapour 400 Watts	926	9	15	950	926	9	15	950	862
105/205/305	Mercury Vapour 700 Watts	11	0	1	12	11	0	1	12	11
106/206/306	Mercury Vapour 1000 Watts	86	22	7	115	86	22	7	115	86
107	Mercury Vapour 250 Watt Cont. Oper.	3	0	0	3	3	0	0	3	3
		15,053	94	245	15,392	15053	94	245	15392	14021
110	Fluorescent 2x24" 70 Watts	897	0	0	897	897	0	0	897	897
111	Fluorescent 2x48" 220 Watts	114	0	0	114	114	0	0	114	114
112	Fluorescent 2x72" 300 Watts	67	0	0	67	67	0	0	67	67
113/213	Fluorescent 4x72" 600 Watts	15	0	0	15	15	0	0	15	15
114/214	Fluorescent 1x96" 110 Watts	5	26	0	31	5	26	0	31	5
115/215	Fluorescent 1x72" 150 Watts	1	3	0	4	1	3	0	4	1
116	Fluorescent 4x48" 440 Watts	2	0	0	2	2	0	0	2	2
217	Fluorescent 1x48"	0	1	0	1	0	1	0	1	0
218	Fluorescent 2x48"	0	0	0	0	0	0	0	0	0
330	Fluorescent 4x35"	0	0	2	2	0	0	2	2	0
350	Fluorescent 4x96"	0	0	76	76	0	0	76	76	0
		1,101	30	78	1,209	1101	30	78	1209	1,101
117	Fluorescent Crosswalk Cont. 4x72"	0	0	1	1	0	0	1	1	0
118	Fluorescent Crosswalk Cont. 2x24"	0	0	17	17	0	0	17	17	0
119	Fluorescent Crosswalk Cont. 4x48"	0	0	23	23	0	0	23	23	0
120	Fluorescent Crosswalk Cont. 2x96"	0	0	30	30	0	0	30	30	0
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21	0	0	21	21	0
		0	0	92	92	0	0	92	92	0
310	Fluorescent Crosswalk 2x24"	0	0	2	2	0	0	2	2	0
311	Fluorescent Crosswalk 4x48"	0	0	5	5	0	0	5	5	0
312	Fluorescent Crosswalk 2x72"	0	0	1	1	0	0	1	1	0
313	Fluorescent Crosswalk 4x72"	0	0	0	0	0	0	0	0	0
314	Fluorescent Crosswalk 1x96"	0	0	25	25	0	0	25	25	0
315	Fluorescent Crosswalk 1x72"	0	0	0	0	0	0	0	0	0
		0	0	33	33	0	0	33	33	0

SCHEDULE 1

2013 STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of MARCH 2011

		MARCH 2011 Adjusted (Quantity)				FORECAST 2013 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
121/221/321	High Pressure Sodium 250 Watts	4,317	171	964	5,452	4317	171	964	5452	4,019
122/326	High Pressure Sodium 400 Watts	2,910	0	89	2,999	2910	0	89	2999	2,709
123/222/322	High Pressure Sodium 70 Watts	35,979	258	5,978	42,215	35979	258	5978	42215	33,496
124/223/323	High Pressure Sodium 100 Watts	43,398	135	2,377	45,910	43398	135	2377	45910	40,402
125/224/324	High Pressure Sodium 150 Watts	5,241	230	125	5,596	5241	230	125	5596	4,879
126	HP Sodium 100 Watts - Cont. Oper.	15	0	0	15	15	0	0	15	15
327	High Pressure Sodium 500 Watts	0	0	3	3	0	0	3	3	0
328	High Pressure Sodium 1000 Watts	0	0	14	14	0	0	14	14	0
329	High Pressure Sodium 1500 Watts	0	0	1	1	0	0	1	1	0
		91,860	794	9,551	102,205	91860	794	9551	102205	85,520
130	Low Pressure Sodium 135 Watts	53	0	0	53	53	0	0	53	49
131/231/331	Low Pressure Sodium 180 Watts	485	39	37	561	485	39	37	561	452
132	Low Pressure Sodium 90 Watts	0	0	0	0	0	0	0	0	0
		538	39	37	614	538	39	37	614	501
140/342	Metallic Arc 400 Watts	1,213	0	159	1,372	1213	0	159	1372	1,129
141/341	Metallic Arc 1000 Watts	981	0	22	1,003	981	0	22	1003	981
142/343	Metallic Arc 250 Watts	100	0	84	184	100	0	84	184	93
143	Metallic Arc 150 Watts	4	0	0	4	4	0	0	4	4
144	Metallic Arc 100 Watts	7	0	0	7	7	0	0	7	7
344	Metallic Arc 175 Watts	0	0	112	112	0	0	112	112	0
345	Metallic Arc 150 Watts	0	0	20	20	0	0	20	20	0
346	Metallic Arc 100 Watts	0	0	0	0	0	0	0	0	0
		2,305	0	397	2,702	2305	0	397	2702	2,214
532/538	LED 44 Watts	0	0	1,732	1,732	0	0	1732	1732	0
539	LED 110 Watts	0	0	2,609	2,609	0	0	2609	2609	0
533	LED 66 Watts	0	0	138	138	0	0	138	138	0
534	LED 88 Watts	0	0	513	513	0	0	513	513	0
537	LED 173 Watts	0	0	38	38	0	0	38	38	0
540	LED 65 Watts	0	0	464	464	0	0	464	464	0
541	LED 55 Watts	0	0	736	736	0	0	736	736	0
542	LED 83 Watts	0	0	1,039	1,039	0	0	1039	1039	0
543	LED 48 Watts	0	0	72	72	0	0	72	72	0
544	LED 72 Watts	0	0	308	308	0	0	308	308	0
	Total	0	0	7,649	7,649	0	0	7649	7649	0
	LED A	7801	0	0	7801	7801	0	0	7801	14,187
	LED B	989	0	0	989	989	0	0	989	1,798
	LED C	373	0	0	373	373	0	0	373	678
	Total	9163	0	0	9163	9163	0	0	9163	16,663
	Total	**120,049**	**957**	**18,089**	**139,095**	**120,049**	**957**	**18,089**	**139,095**	**120,049**

SCHEDULE 2

2013 STREET / CROSSWALK LIGHTING STUDY
CALCULATION OF MAINTENANCE COSTS BY FIXTURE TYPE

(A) Code	(B) Lamp Type	(C) Service Life (Years)	(D) Maintenance Weighting Factors	(E) # of Full Chg & Eng.+Maint. Fixtures	(F) Weighting Total	(G) Cost Per Year	(H) Cost Per Month
A	Mercury Vapour	6.000	1.0000	4,502	4,502	$50.94	$4.25
B	Mercury Vapour - 125W	4.500	1.3333	9,642	12,856	$67.92	$5.66
C	Fluorescent	3.000	2.0000	1,131	2,262	$101.89	$8.49
D	High Pressure Sodium (Note1)	6.000	1.0000	86,329	86,329	$50.94	$4.25
E	Metallic Arc 100W, 150W & 250W	2.500	2.4000	103	248	$122.26	$10.19
F	Metallic Arc 400W	3.750	1.6000	1,129	1,807	$81.51	$6.79
G	Metallic Arc 1000W	2.500	2.4000	981	2,354	$122.26	$10.19
H	Low Pressure Sodium	2.000	3.0000	540	1,620	$152.83	$12.74
I	LED	20.000	0.3000	0	0	$15.28	$1.27
				104,358	111,978		

Street Lighting Maint. Expenses
(from 2013 COSS, Exhibit 6A) **$5,704,509**

Annual Cost of High Pressure Sodium
($5,704,508.92 / 111978.336007024 weighted fixtures) **$50.94**

Note 1: Maintenance weighting factors relative to High Pressure Sodium fixture, index = 1.0
Factor is: HPS service life / various fixture service lives

SCHEDULE 3

2013 STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

Gross Plant Value (including installation costs) less Retirements of Non-LED Street Lighting Equipment, 2013 Average → **Total** **$43,821,074**

Description	Unit Cost Mar/1977	Unit Cost Mar-11	Historical 11-Mar Fixtures	Average # of Fixtures bfr LED	Average # of Fixtures aft LED	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	27	27	27	$1,733	
Incandescent > 300 Watts	$63.62	$79.53	2	2	2	$159	
Mercury Vapour 100 Watts	$76.55	$229.55	251	251	234	$57,616	
Mercury Vapour 125 Watts	$77.16	$204.78	10,349	10,349	9,635	$2,119,288	
Mercury Vapour 175 Watts	$85.30	$201.27	2,474	2,474	2,303	$497,946	
Mercury Vapour 250 Watts	$87.24	$291.38	953	953	887	$277,681	
Mercury Vapour 400 Watts	$107.82	$301.45	926	926	862	$279,143	
Mercury Vapour 700 Watts	$485.12	$449.78	11	11	11	$4,948	
Mercury Vapour 1000 Watts	$492.29	$579.25	86	86	86	$49,816	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$291.38	3	3	3	$874	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	897	897	897	$119,346	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	114	114	114	$18,797	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	67	67	$14,968	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	15	15	$5,507	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	5	5	$1,000	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	1	1	1	$152	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	2	2	$472	
High Pressure Sodium 70 Watts	*N/A*	$207.51	35,979	35,979	33,496	$7,465,995	
High Pressure Sodium 100 Watts	*N/A*	$210.65	43,413	43,413	40,417	$9,144,775	
High Pressure Sodium 150 Watts	*N/A*	$232.66	5,241	5,241	4,879	$1,219,396	
High Pressure Sodium 250 Watts	$156.49	$231.67	4,317	4,317	4,019	$1,000,140	
High Pressure Sodium 400 Watts	$173.73	$246.21	2,910	2,910	2,709	$716,479	
High Pressure Sodium 1000 Watts	*N/A*	$615.53	0	0	0	$0	
Low Pressure Sodium 90 Watts	*N/A*	$554.53	0	0	0	$0	
Low Pressure Sodium 135 Watts	$371.69	$554.53	53	53	49	$29,390	
Low Pressure Sodium 180 Watts	$226.10	$880.14	485	485	452	$426,867	
Metallic Additive 250 Watts	*N/A*	$298.33	104	104	97	$31,026	
Metallic Additive 400 Watts	$358.84	$305.76	1,213	1,213	1,129	$370,885	
Metallic Additive 1000 Watts	$560.49	$526.16	981	981	981	$516,159	
Metallic Additive 100 Watts	*N/A*		7	7	7	$0	
			110,886	110,886	103,386		**24,370,558**
							$19,450,516
							$188.13
Total # of light types being displaced by LED			108,675	108,675	101,175		
Total Installation Costs (Labour)							
Installation Costs per Fixture							

Escalation Factor (Incandescent)	125%
Escalation Factor (Fluorescent)	125%

Note: 2007 costs are based on stores material inventory cost as of June 2007 with the exception of Incandescent and fluorescent which have been assumed at 130% of 1977 costs.

Sample Material Cost - 100 Watt High Intensity (Pressure) Sodium :
Inventory Prices as of March 2011

Fixture, Ballast & Photocell	$124.02
Bracket Assembly (Davit)	67.32
Wire	16.71
Miscellaneous Hardware	2.60
Lamp Replacement	8.62
TOTAL	**$219.27**

SCHEDULE 4

2013 STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

	Non Led	LED
Depreciation Rate for 2013	5.33%	5.33%
# of Years	18.76	18.76
Tax Adjusted Weighted Average Cost of Capital	10.40%	9.31%
Pre-tax WACC	7.76%	7.76%
Tax-related Gross-up Depreciation factor	31.00%	31.00%
Salvage Rate (% of Depreciation)	0.00%	0.00%
Salvage Rate incl in Depr. Rate for 2013	0.00%	0.00%
# of Years	N/A	N/A

Revenue Correction factor	Non LED	LED
Simulated at current meth.	$7,646,756	$1,905,943
Total cost per COSS (and adjusted for energy)	$3,899,055	$1,962,839
Revenue Correction Factor	**0.5099**	**1.0299**

	Material Cost January 2010	Labour Cost	Total	Before Correction Factor: Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost	Correction Factor	Aligned with COSS results: Total Annual Cost	Monthly Cost	2013 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Incandescent < 300 Watts	$64.20	188.13	$252.33	$19.49	$26.24	$0.00	$45.73	0.510	$23.32	$1.94	27	526.28	708.56		1,234.84	629.64
Incandescent > 300 Watts	79.53	188.13	267.66	$20.68	$27.84	$0.00	48.51	0.510	$24.74	2.06	2	41.35	55.67		97.02	49.47
Mercury Vapour 100 Watts	229.55	188.13	417.68	$32.26	$43.44	$0.00	75.70	0.510	$38.60	3.22	234	7,539.48	10,150.72		17,690.20	9,020.17
Mercury Vapour 125 Watts	204.78	188.13	392.92	$30.35	$40.86	$0.00	71.21	0.510	$36.31	3.03	9,635	292,429.19	393,709.55		686,138.74	349,859.82
Mercury Vapour 175 Watts	201.27	188.13	389.41	$30.08	$40.50	$0.00	70.58	0.510	$35.99	3.00	2,303	69,282.67	93,278.13		162,560.81	82,889.20
Mercury Vapour 250 Watts	291.38	188.13	479.51	$37.04	$49.87	$0.00	86.91	0.510	$44.31	3.69	887	32,863.40	44,245.36		77,108.76	39,317.49
Mercury Vapour 400 Watts	301.45	188.13	489.58	$37.82	$50.92	$0.00	88.74	0.510	$45.25	3.77	862	32,603.24	43,895.09		76,498.33	39,006.24
Mercury Vapour 700 Watts	449.78	188.13	637.92	$49.28	$66.34	$0.00	115.62	0.510	$58.95	4.91	11	542.04	729.78		1,271.82	648.50
Mercury Vapour 1000 Watts	579.25	188.13	767.39	$59.28	$79.81	$0.00	139.09	0.510	$70.92	5.91	86	5,097.90	6,863.52		11,961.42	6,099.09
Mercury Vapour 250 Watt Cont. Oper.	291.38	188.13	479.51	$37.04	$49.87	$0.00	86.91	0.510	$44.31	3.69	3	111.12	149.61		260.73	132.94
Fluorescent 2x24" 70 Watts	133.05	188.13	321.18	$24.81	$33.40	$0.00	58.21	0.510	$29.68	2.47	897	22,254.90	29,962.70		52,217.60	26,625.58
Fluorescent 2x48" 220 Watts	164.89	188.13	353.02	$27.27	$36.71	$0.00	63.98	0.510	$32.63	2.72	114	3,108.75	4,185.43		7,294.18	3,719.28
Fluorescent 2x72" 300 Watts	223.40	188.13	411.53	$31.79	$42.80	$0.00	74.59	0.510	$38.03	3.17	67	2,129.90	2,867.58		4,997.48	2,548.20
Fluorescent 4x72" 600 Watts	367.15	188.13	555.28	$42.89	$57.75	$0.00	100.64	0.510	$51.32	4.28	15	643.41	866.24		1,509.65	769.77
Fluorescent 1x96" 110 Watts	200.00	188.13	388.13	$29.98	$40.37	$0.00	70.35	0.510	$35.87	2.99	5	149.91	201.83		351.74	179.35
Fluorescent 1x72" 150 Watts	151.53	188.13	339.66	$26.24	$35.32	$0.00	61.56	0.510	$31.39	2.62	1	26.24	35.32		61.56	31.39
Fluorescent 4x48" 440 Watts	236.14	188.13	424.27	$32.77	$44.12	$0.00	76.90	0.510	$39.21	3.27	2	65.55	88.25		153.80	78.42
High Pressure Sodium 70 Watts	207.51	188.13	395.64	$30.56	$41.15	$0.00	71.71	0.510	$36.56	3.05	33,496	1,023,708.19	1,378,260.79		2,401,968.98	1,224,755.84
High Pressure Sodium 100 Watts	210.65	188.13	398.78	$30.80	$41.47	$0.00	72.28	0.510	$36.85	3.07	40,417	1,245,018.73	1,676,220.34		2,921,239.08	1,489,529.90
High Pressure Sodium 150 Watts	232.66	188.13	420.80	$32.51	$43.76	$0.00	76.27	0.510	$38.89	3.24	4,879	158,602.93	213,533.71		372,136.64	189,751.21
High Pressure Sodium 250 Watts	231.67	188.13	419.81	$32.43	$43.66	$0.00	76.09	0.510	$38.80	3.23	4,019	130,333.56	175,473.48		305,807.04	155,929.97
High Pressure Sodium 400 Watts	246.21	188.13	434.35	$33.55	$45.17	$0.00	78.72	0.510	$40.14	3.35	2,709	90,897.55	122,379.13		213,276.68	108,749.06
High Pressure Sodium 1000 Watts	615.53	188.13	803.67	$62.08	$83.58	$0.00	145.66	0.510	$74.27	6.19	-	-	-		-	-
Low Pressure Sodium 90 Watts	554.53	188.13	742.67	$57.37	$77.24	$0.00	134.61	0.510	$68.63	5.72	-	-	-		-	-
Low Pressure Sodium 135 Watts	554.53	188.13	742.67	$57.37	$77.24	$0.00	134.61	0.510	$68.63	5.72	49	2,830.68	3,811.06		6,641.74	3,386.60
Low Pressure Sodium 180 Watts	880.14	188.13	1,068.27	$82.52	$111.10	$0.00	193.62	0.510	$98.73	8.23	452	37,260.27	50,165.05		87,425.31	44,577.87
Metallic Arc 250 Watts	298.33	188.13	486.46	$37.58	$50.59	$0.00	88.17	0.510	$44.96	3.75	97	3,638.35	4,898.46		8,536.80	4,352.89
Metallic Arc 400 Watts	305.76	188.13	493.89	$38.15	$51.36	$0.00	89.52	0.510	$45.64	3.80	1,129	43,083.98	58,005.75		101,089.74	51,545.31
Metallic Arc 1000 Watts	$526.16	188.13	$714.29	$55.18	$74.29	$0.00	$129.46	0.510	$66.01	$5.50	981	54,128.04	72,874.82		127,002.86	64,758.33
Metallic Additive 100 Watts	$0.00	188.13	$188.13	$14.53	$19.57	$0.00	$34.10	0.510	$17.39	$1.45	7	94.71	127.51		222.22	113.31
Total											**103,386**	**$3,259,012**	**$4,387,743**		**$7,646,756**	**$3,899,055**

	Material Cost January 2010	Labour Cost	Total	Before Correction Factor: Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost	Correction Factor	Aligned with COSS results: Total Annual Cost	Monthly Cost	2013 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
LED A	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	1.030	$117.80	9.82	14,187	816,878.94	984,530.70	(178,682.77)	1,622,726.86	1,671,168.38
LED B	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	1.030	$117.80	9.82	1,798	103,538.14	124,787.75	(22,647.77)	205,678.13	211,818.01
LED C	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	1.030	$117.80	9.82	678	39,032.37	47,043.16	(8,537.88)	77,537.66	79,852.31
											16,663	**$959,449**	**$1,156,362**	**-$209,868**	**$1,905,943**	**$1,962,839**

SCHEDULE 5

2013 STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Rate by Components For 2013 Street Light Rates

	Proportion	Cost	Extended	Non-LED	Extended	LED
a) Weighted Average Cost of Capital - Pretax						
ST Debt	6.3%	4.1%	0.3%	0.26%	0.3%	0.26%
LT Debt	52.5%	7.3%	3.8%	3.83%	3.8%	3.83%
Preferred	3.7%	6.0%	0.2%	0.22%	0.2%	0.22%
Common	37.5%	9.2%	3.5%	3.45%	3.5%	3.45%
	100.0%		7.8%		7.8%	
WACC - pretax cost				7.76%		7.76%
b) Additional income tax for common equity						
Extended equity cost			3.45%		3.45%	
Effective tax rate (excluding surtax)			31.0%		31.0%	
Income tax			1.55%		1.55%	
WACC - equity tax cost				1.55%		1.55%
c) Large Corporations Tax						
Provincial capital tax (2013)			0.000%		0.000%	
Federal capital tax (2013)			0.000%		0.000%	
Ave. NBV - Street Lighting			$15.949		$8.148	
Ave. NBV - Assigned GP Plt.			1.239		0.633	
Ave. Deferred Chgs & W/C			1.530		0.782	
NPV - Total Street Lighting			$18.718		$9.563	
Provincial capital tax			$0.000		$0.000	
Federal capital tax			$0.000		$0.000	
Total			$0.000		$0.000	
Percentage of NBV			0.00%		0.00%	
WACC - Large Corporations Tax				0.00%		0.00%
d) Grants in Lieu of Property Tax						
Total 2013 Forecasted Expense			$37.500		N/A	
St. Lgts. % of Total Electric Plant			0.55%		N/A	
St. Lgts. Allocated Amount			$0.205		N/A	
Percentage of NBV			1.09%		N/A	
WACC - Grants in Lieu of Property Tax				1.09%		0.00%
Total WACC - Interest / Carrying Cost				**10.40%**		**9.31%**

SCHEDULE 5A

2013 STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components

For 2013 Street Light Rates

Depreciation Rate	**5.33%**
Salvage Rate	**0.00%**
Salvage Incl. in Depreciation Rate	**0.00%**
Gross-up factor for tax purposes (LED only)	**31.00%**

		Non LED	Non LED	LED	LED Deferral
Gross Plant Value (YA)			$43,821	$11,334	
Net Plant Value (YA)			$15,949	$11,020	$2,606
a) Weighted Average Cost of Capital - Pretax					
	ST Debt	0.26%		28	7
	LT Debt	3.83%		422	100
	Subtotal		*589*	*451*	*107*
	Preferred	0.22%	$35.7	25	6
	Common	3.45%	$534.9	380	90
	WACC - pretax cost	7.76%	$1,159.2	$855	$202
b) Additional income tax for common equity					
	WACC - equity tax cost	1.55%		171	40
c) Large Corporations Tax					
	WACC - Large Corporations Tax	0.00%		0	0
Subtotal			*$233.4*	*171*	*40*
d) Grants in Lieu of Property Tax					
	WACC - Grants in Lieu of Property Tax	1.09%	$164.2	0	28
Subtotal Financing Expense		**10.40%**	**$1,556.8**	**$1,026.1**	**$271.0**
Depreciation Expense			**$2,342.2**	**$604.121**	**$0.0**
Gross up for Tax Purposes				**$271.4**	**$0.0**
Total Depreciation Expense including Gross up for Tax Purposes			**$2,342.2**	**$875.5**	**$0.0**
CCA			**$0.0**	**-$209.9**	
TOTAL CAPITAL COST EXPENSE			**$3,899.1**	**$1,691.8**	**$271.025**

SCHEDULE 6

2013 STREET / CROSSWALK LIGHTING STUDY
AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

Light Type Street Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Incandescent < 300 Watts	$51.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Incandescent > 300 Watts	$63.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mercury Vapour 100 Watts	$229.55	$122.41	$15.99	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 125 Watts	$204.78	$102.95	$10.68	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 175 Watts	$201.27	$102.95	$7.17	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 250 Watts	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 400 Watts	$301.45	$198.75	$8.98	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 700 Watts	$449.78	$318.97	$37.10	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 1000 Watts	$579.25	$439.19	$46.35	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 250 Watt Cont. Oper.	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Fluorescent 2x24" 70 Watts	$106.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x48" 220 Watts	$131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x72" 300 Watts	$178.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x72" 600 Watts	$293.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x96" 110 Watts	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x72" 150 Watts	$121.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x48" 440 Watts	$188.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High Pressure Sodium 70W	$207.51	$120.88	$8.81	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 100W	$210.65	$124.02	$8.62	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 150W	$232.66	$146.03	$8.67	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 250 Watts	$231.67	$142.48	$10.59	$4.52	$69.88	$16.71	$1.09	$1.51
High Pressure Sodium 400 Watts	$246.21	$157.02	$13.19	$4.52	$69.88	$16.71	$1.09	$1.51
Low Pressure Sodium 90W	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 135 Watts	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 180 Watts	$880.14	$788.99	$54.77	$4.52	$67.32	$16.71	$1.09	$1.51
Metallic Additive 250W	$298.33	$190.30	$18.83	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 400 Watts	$305.76	$201.63	$14.93	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 1000 Watts	$526.16	$405.65	$31.31	$0.00	$69.88	$16.71	$1.09	$1.51
LED A	$420.00							
LED B	$420.00							
LED C	$420.00							

Light Type Flood Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Mercury Vapour 175 Watts	$67.32	$53.03	$7.17	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 250 Watts	$412.88	$397.90	$7.86	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 400 Watts	$297.27	$281.17	$8.98	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 1000 Watts	$507.90	$439.19	$46.35	$19.77	$0.00	$0.00	$1.09	$1.51
HIS 150W	$215.75	$183.39	$25.23	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 250 Watts	$202.12	$184.41	$10.59	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 400 Watts	$215.26	$194.95	$13.19	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Additive 250W	$216.25	$190.30	$18.83	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 400 Watts	$223.69	$201.63	$14.93	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 1000 Watts	$459.33	$405.65	$31.31	$19.77	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 70W HPS	$197.77	$195.17	$8.81	$4.52	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 100W HPS	$143.10	$140.50	$8.62	$4.52	$0.00	$0.00	$1.09	$1.51

SCHEDULE 7

2013 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0000386440	LAMP FLUORESCENT 40W 48	1.35	
0000386450	LAMP FLUORESCENT 40W 48	1.36	
0000386700	LAMP FLUORESCENT 75W 96	3.49	
0000386710	LAMP FLUORESCENT 205W	3.95	
0000387070	LAMP FLUORESCENT 35W 24	4.19	
0000387190	LAMP FLUORESCENT 60W 48	3.19	
0000387360	LAMP FLUORESCENT 85W 72	6.54	
0000388000	LAMP 100 WATT M.V.	15.99	
0000388180	LAMP 125 WATT M.V.	10.68	
0000388330	LAMP 175 WATT M.V.	7.17	
0000388500	LAMP 250 WATT M.V.	7.86	
0000388660	LAMP 400 WATT M.V.	8.98	
0000388770	LAMP 700 WATT M.V.	37.10	
0000388980	LAMP 1000 WATT MV	46.35	
0000388990	LAMP 70 WATT H.P.S.	8.81	
0000389000	LAMP 100 WATT H.P.S.	8.62	
0000389030	LAMP 135 WATT L.P.S.	44.00	
0000389040	LAMP 150 WATT HPS 100V	25.23	
0000389060	LAMP 150 WATT H.P.S.55V	8.67	
0000389090	LAMP 180 WATT L.P.S.	54.77	
0000389250	LAMP 250 WATT H.P.S.	10.59	
0000389400	LAMP 400 WATT H.P.S.	13.19	
0000389450	LAMP 1000W HPS	60.32	
0000389700	LAMP HALIDE 250W	18.83	
0000389770	LAMP HALIDE 400W	14.93	
0000389810	LAMP HALIDE 1000W	31.31	
0000389900	LAMP STREET LITE SIGNAL	2.21	
0002103270	CONDUIT FLEX BLK 1/2"	4.36	
0050091540	BOLT LAG 1/2"X 4" GALV	0.46	
0050103120	BOLT MACHINE 5/8" X 12"	1.05	
0054223510	CRIMPIT #2/0- #8 WR139	0.55	
0057151000	BRACKET 10'L	101.45	
0057152040	BRACKET 1 1/4"X4' FIXED	60.02	
0057152220	BRACKET 4'X 2' 16" TEN	27.46	
0057154060	BRACKET 1 1/4"X6' LOWER	67.32	
0057155060	BRACKET SWIVEL 1 1/4 X6	18.91	
0057155720	BRACKET TAPERED 6' X 2"	48.90	
0057155723	BRACKET TAPERED 8'	87.05	
0057155725	BRACKET TAPERED 2"X10'	106.44	
0057156020	BRACKET LOWER 2" X 6'	69.88	
0057156080	BRACKET FIXED 2" X 8'	87.48	
0057157010	BRACKET TAPERED 12'L	173.80	
0057158140	PLATE POLE ST LITE 1 1/	9.46	
0057158220	PLATE POLE ST LIGHT 2"	26.24	

SCHEDULE 7

2013 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057350350	LUMINAIRE LPS 135W	463.38	
0057350720	LUM LPS 180W 120/240/347 V	788.99	R04B
0057350750	LUMINAIRE LPS 180W 240V	493.30	XX
0057350800	LUMINAIRE LPS 180W 347V	780.20	XX
0057350830	LUMINAIRE HPS 70W POLY	73.33	XX
0057350835	LUM. 70W POLY C/W LAMP	99.23	XX
0057350836	LUM 70W POLY ALUM.ALLOY	97.70	XX
0057350837	LUMINAIRE 70W HPS CWA ACRY	120.88	C01A
0057350850	LUMINAIRE HPS 70W GLASS	69.32	XX
0057350855	LUM. 70W GLASS C/W LAMP	97.68	C03A
0057350856	LUM 70W GLASS AL. ALLOY	99.37	M12D
0057350857	LUM. 70W GLASS CWI BAL.	120.32	M08A
0057350860	LUM 100W HPS POLY	75.00	XX
0057350865	LUM. 100W POLY C/W LAMP	100.21	XX
0057350866	LUMINAIRE 100W ACRYLIC HPS	124.02	C07A
0057350867	LUM 100W POLY AL. ALLOY	98.37	XX
0057350875	LUM. 100W GLASS C/WLAMP	98.76	XX
0057350877	LUM. 100W GLASS CWI BAL	135.75	XX
0057350880	LUMINAIRE HPS 150W GLAS	82.27	XX
0057350885	LUM. 150W GLASS C/WLAMP	100.95	XX
0057350886	LUMINAIRE 150W HPS CWI GLAS	146.03	M05A
0057350887	LUM. 150W HPS 240V GLAS	150.88	C09A
0057350890	LUMINAIRE HPS 150W POLY	79.24	XX
0057350895	LUM. 150W POLY C/W LAMP	102.95	XX
0057351315	LUMINAIRE 250W HPS CWI GLAS	142.48	C07A
0057351400	LUMINAIRE 250W HPS CWI 347V	160.68	C05A
0057351710	LUMINAIRE HPS 400W GLAS	109.60	XX
0057351715	LUMINAIRE 400W HPS CWI 120/2	157.02	M12A
0057351720	LUMINAIRE HPS 400W 240V	204.30	XX
0057351730	LUMINAIRE HPS 400W 347V	196.00	XX
0057351760	LUMINAIRE 400W 600V HPS CWI	172.33	M12A
0057353330	LUMINAIRE MTL-HLDE 400W	281.54	XX
0057353500	LUMINAIRE HALIDE 1000 W	300.00	XX
0057353550	LUMINAIRE HALIDE 1000 W	294.79	T01C
0057400920	AREA LIGHT MV 125 W	107.76	XX
0057401200	LUMINAIRES 70W H-P.S.	107.80	D14B
0057401205	DUSK-T-DAWN 70W HPS CWA	195.17	D08B
0057402020	AREA LIGHT MV 175 W	92.88	XX
0057402100	LUMINAIRES 100W H.P.S.	106.37	XX
0057402105	DUSK-T-DAWN 100W HPS CWA	140.50	C15A
0057402150	FLOODLIGHT 150W HPS CWI	183.39	C17A
0057402240	FLOODLIGHT M.V. 175W	53.03	
0057403330	FLOODLIGHT M V 250 W	397.90	XX
0057403500	FLOODLIGHT 250W HPS CWI	184.41	

SCHEDULE 7

2013 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057404050	FLOODLIGHT M V 400 W	281.17	XX
0057404600	FLOODLIGHT 400W HPS CWI	194.95	C11A
0057408250	FLOODLIGHT MTL HAL.250W	190.30	D05B
0057408500	FLOODLIGHT 400W MTL-HAL CW	201.63	D03A
0057409000	FLOODLIGHT 1000W MH CWI	405.65	
0057409380	FLOODLIGHT M V 1000 W	439.19	XX
0057600450	BRACKET & ADAPTORS	9.40	
0057601010	CAP SHORTING TWIST LOCK	4.87	
0057601200	CONTROL 120 V PHOTO	7.05	
0057601400	CONTROL ELECT 120V PHOTOC	4.52	
0057602000	PHOTO CONTROL 120V HD	19.77	
0057602400	CONTROL 240V ELECT PHOTOC	10.96	
0057602960	GUARD WIRE FOR ST-LITE	50.44	
0057603800	REFRACTOR GLASS	32.60	
0057603900	REFRACTORS POLYCARBON #	0.00	
0057604020	REFRACTOR POLY LU B2214	48.03	
0057604050	REFRACTOR POLY LU B2217	73.74	
0057604080	REFRACTOR POLYCARBON #9	21.07	
0057604170	REFRACTOR GLASS	66.37	
0057604200	REFRACTOR ACRYLIC VB15	40.70	
0057604210	REFRACTOR POLY LUM VB15	78.68	
0057604220	REFRACTOR AREA LIGHT	18.99	
0057604240	REFRACTOR GLASS OV15	16.00	
0057604250	REFRACTOR POLY LUM 0V15	24.00	
0057604255	REFRACTOR STREETLIGHT OV	18.12	
0057604270	REFRACTOR GLASS OV25	25.89	
0057604280	REFRACTOR POLY OV25	92.87	
0057604300	REFRACTOR GLASS OV50	17.50	
0057605800	REDUCER LAMPHOLDER,	6.25	
0057606100	REFRACTOR 125 W M V	34.36	
0057606500	REFRACTOR FOR SODIUM	71.31	
0057606550	REFRACTOR FOR SODIUM	88.62	
0057606700	REFRACTOR 250 W M V	38.69	
0057606950	REFRACTOR 400 W M V	33.01	
0057607300	RELAY 30 AMP 110 V MURC	33.89	
0057607330	RELAY 30 AMP 125 V	140.04	
0057607400	RELAY 60 AMP 115 V	214.85	
0057607440	RELAY 60 AMP 250 V	191.29	
0057608690	STARTERS HPS LUMINAIRES	31.63	
0057608700	STARTER FOR HPS 70-150W	40.95	
0057608703	STARTER FOR HPS 55V	41.17	
0057608710	STARTER FOR SODIUM	40.41	
0057608713	STARTER KIT HPS 55V 70/	31.75	
0057608720	STARTER FOR HPS 150-400	40.76	

SCHEDULE 7

2013 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057608722	STARTER FOR HPS 100V	36.35	
0057608730	STARTER FOR SODIUM	48.16	
0065734220	CABLE CU ST-LITE 2C #12	1.03	

SCHEDULE 8

2013 STREET / CROSSWALK LIGHTING STUDY
LAMP LIFE ANALYSIS
September 2005

Assumptions: Total annual photocell operating time is based on 4,000 hours per year or 333 hours per month.
All Average Rated Life Spans are as indicated in the IES Lighting Handbook, 1981 Edition
(IES = Illuminating Engineering Society)

Lamp Type	Average Life (Hrs)	Burning Hours per Year	Service Life (Years)	Life Relative to 100W HPS	Replacements Relative to 100W HPS
Incandescent	2500	4000	0.6	0.10	9.60
Flourescent (48 in., T12, Recess Base)	12000	4000	3.0	0.50	2.00
Mercury Vapour	24000	4000	6.0	1.00	1.00
Mercury Vapour 125W *See Note	18000	4000	4.5	0.75	1.33
Metal Halide 175W	7500	4000	1.9	0.31	3.20
Metal Halide 250W	10000	4000	2.5	0.42	2.40
Metal Halide 400W	15000	4000	3.8	0.63	1.60
Metal Halide 1000W	10000	4000	2.5	0.42	2.40
High Pressure Sodium 70W	24000	4000	6.0	1.00	1.00
High Pressure Sodium 100W	24000	4000	6.0	1.00	1.00
Low Pressure Sodium	8000	4000	2.0	0.33	3.00

*** No Average life data was available for this lamp size in the references listed above. 75% of the quoted life for all Mercury Lamps was used.**

Nova Scotia Power Inc.
LED Streetlights
2013 CCA Schedule
Millions of dollars

Schedule 9

		1	2	3	4	5	6	7	8	9
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
		12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
Beginning UCC										
	8%	-	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320
		-	**-**	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**
Additions										
	8%		16,924,872	17,322,621	-	-	-	-	-	-
		-	**16,924,872**	**17,322,621**	**-**	**-**	**-**	**-**	**-**	**-**
CCA										
	8%	-	676,995	1,992,735	2,526,221	2,324,123	2,138,193	1,967,138	1,809,767	1,664,986
		-	**676,995**	**1,992,735**	**2,526,221**	**2,324,123**	**2,138,193**	**1,967,138**	**1,809,767**	**1,664,986**
Ending UCC										
	8%	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320	19,147,335
		-	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**	**19,147,335**
	Tax Rate:	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	Tax Savings from CCA :	-	209,868	617,748	783,129	720,478	662,840	609,813	561,028	516,146

Nova Scotia Power Inc.
LED Streetlights
2013 CCA Schedule
Millions of dollars

Schedule 9

	10 2021 12/31/2021	11 2022 12/31/2022	12 2023 12/31/2023	13 2024 12/31/2024	14 2025 12/31/2025	15 2026 12/31/2026	16 2027 12/31/2027	17 2028 12/31/2028	18 2029 12/31/2029	19 2030 12/31/2030	20 2031 1/1/2031
Beginning UCC											
	19,147,335	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381
	19,147,335	**17,615,548**	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**
Additions											
	-	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
CCA											
	1,531,787	1,409,244	1,296,504	1,192,784	1,097,361	1,009,572	928,807	854,502	786,142	723,251	665,390
	1,531,787	**1,409,244**	**1,296,504**	**1,192,784**	**1,097,361**	**1,009,572**	**928,807**	**854,502**	**786,142**	**723,251**	**665,390**
Ending UCC											
	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381	7,651,991
	17,615,548	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**	**7,651,991**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	474,854	436,866	401,916	369,763	340,182	312,967	287,930	264,896	243,704	224,208	206,271

Nova Scotia Power Inc.
LED Streetlights
2013 CCA Schedule
Millions of dollars

Schedule 9

	21	22	23	24	25	26	27	
	2032	2033	2034	2035	2036	2037	2038	
	1/2/2031	1/3/2031	1/4/2031	1/5/2031	1/6/2031	1/7/2031	1/8/2031	**Total**
Beginning UCC								
	7,651,991	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	**357,611,954**
	7,651,991	**7,039,831**	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**357,611,954**
Additions								
	-	-	-	-	-	-	-	
	-	**-**	**-**	**-**	**-**	**-**	**-**	**34,247,493**
CCA								
	612,159	563,187	518,132	476,681	438,547	403,463	371,186	**29,978,856**
	612,159	**563,187**	**518,132**	**476,681**	**438,547**	**403,463**	**371,186**	**29,978,856**
Ending UCC								
	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	4,268,637	**361,880,591**
	7,039,831	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**4,268,637**	**361,880,591**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	**8**
	189,769	174,588	160,621	147,771	135,949	125,073	115,068	**9,293,445**

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent :														
Incandescent < 300 Watts - Note 1	001	97	$14.43	4.25	$1.94	$20.62	$6,680	$17.54	17.5%	27	$997	0.291	7.857	
Incandescent > 300 Watts - Note 1	002	154	22.91	4.25	2.06	$29.22	701	$24.55	19.0%	2	112	0.462	0.924	
Incandescent < 300 Watts - Note 1	003	97	14.43	0.00	0.00	$14.43	1,212	$11.68	23.5%	7	231	0.291	2.037	
							8,594			36	1,340			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43	6.40	4.25	3.22	$13.86	38,871	$12.71	9.1%	234	3,239	0.129	30.144	
Mercury Vapour 125 Watts	101	52	7.74	5.66	3.03	$16.43	1,899,171	$14.74	11.5%	9,635	195,547	0.156	1,503.026	
Mercury Vapour 175 Watts	102	69	10.27	4.25	3.00	$17.51	484,078	$15.52	12.8%	2,303	55,020	0.207	476.775	
Mercury Vapour 250 Watts	103	97	14.43	4.25	3.69	$22.37	238,149	$19.82	12.9%	887	27,173	0.291	258.184	
Mercury Vapour 400 Watts	104	154	22.91	4.25	3.77	$30.93	319,931	$26.78	15.5%	862	42,921	0.462	398.287	
Mercury Vapour 700 Watts	105	260	38.68	4.25	4.91	$47.84	6,315	$41.04	16.6%	11	897	0.780	8.580	
Mercury Vapour 1000 Watts	106	363	54.01	4.25	5.91	$64.17	66,219	$54.75	17.2%	86	9,718	1.089	93.654	
Mercury Vapour 250 Watt Cont. Oper.	107	212	24.49	8.49	3.69	$36.67	1,320	$31.61	16.0%	3	182	0.291	0.873	0.873
Mercury Vapour 125 Watts	201	52	7.74	5.66	0.00	$13.40	1,126	$11.12	20.6%	7	192	0.156	1.092	
Mercury Vapour 175 Watts	202	69	10.27	4.25	0.00	$14.52	3,658	$11.94	21.6%	21	649	0.207	4.347	
Mercury Vapour 250 Watts	203	97	14.43	4.25	0.00	$18.68	7,844	$15.33	21.8%	35	1,405	0.291	10.185	
Mercury Vapour 400 Watts	204	154	22.91	4.25	0.00	$27.16	2,933	$22.19	22.4%	9	536	0.462	4.158	
Mercury Vapour 700 Watts	205	260	38.68	4.25	0.00	$42.93	0	$34.97	22.8%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363	54.01	4.25	0.00	$58.26	15,379	$47.38	23.0%	22	2,871	1.089	23.958	
Mercury Vapour 125 Watts	301	52	7.74	0.00	0.00	$7.74	1,022	$6.25	23.8%	11	197	0.156	1.716	
Mercury Vapour 175 Watts	302	69	10.27	0.00	0.00	$10.27	19,349	$8.29	23.9%	157	3,730	0.207	32.499	
Mercury Vapour 250 Watts	303	97	14.43	0.00	0.00	$14.43	9,351	$11.68	23.5%	54	1,782	0.291	15.714	
Mercury Vapour 400 Watts	304	154	22.91	0.00	0.00	$22.91	4,124	$18.54	23.6%	15	787	0.462	6.930	
Mercury Vapour 700 Watts	305	260	38.68	0.00	0.00	$38.68	464	$31.32	23.5%	1	88	0.780	0.780	
Mercury Vapour 1000 Watts	306	363	54.01	0.00	0.00	$54.01	4,537	$43.73	23.5%	7	864	1.089	7.623	
							3,123,838			14,360	347,798			

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30	4.46	8.49	2.47	$15.42	166,025	$13.82	11.6%	897	17,275	0.091	81.627	
Fluorescent 2x48" 220 Watts	111	85	12.65	8.49	2.72	$23.86	32,639	$20.76	14.9%	114	4,242	0.254	28.956	
Fluorescent 2x72" 300 Watts	112	116	17.26	8.49	3.17	$28.92	23,252	$25.09	15.2%	67	3,076	0.348	23.316	
Fluorescent 4x72" 600 Watts	113	222	33.03	8.49	4.28	$45.80	8,243	$39.26	16.6%	15	1,176	0.665	9.975	
Fluorescent 1x96" 110 Watts	114	47	6.99	8.49	2.99	$18.47	1,108	$16.52	11.8%	5	117	0.141	0.705	
Fluorescent 1x72" 150 Watts	115	60	8.93	8.49	2.62	$20.04	240	$17.61	13.8%	1	29	0.180	0.180	
Fluorescent 4x48" 440 Watts	116	166	24.70	8.49	3.27	$36.46	875	$31.25	16.7%	2	125	0.499	0.998	
							232,383			1,101	26,040			
Fluorescent 4x72" 600 Watts	213	222	33.03	8.49	0.00	$41.52	0	$34.02	22.1%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47	6.99	8.49	0.00	$15.48	4,830	$12.95	19.6%	26	790	0.141	3.666	
Fluorescent 1x72" 150 Watts	215	60	8.93	8.49	0.00	$17.42	627	$14.53	19.9%	3	104	0.180	0.540	
Fluorescent 4x48" 440 Watts	216	166	24.70	8.49	0.00	$33.19	*0*	$27.32	21.5%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49	7.29	8.49	0.00	$15.78	189	$13.18	19.8%	1	31	0.146	0.146	
Fluorescent 2x48" 220 Watts	218	85	12.65	8.49	0.00	$21.14	0	$17.54	20.5%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47	6.99	0.00	0.00	$6.99	168	$5.65	23.7%	2	32	0.140	0.280	
							5,814			32	957			
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486	56.15	0.00	0.00	$56.15	674	$45.45	23.5%	1	128	0.665	0.665	0.665
Fluorescent 2x24" 70 Watts	118	66	7.62	0.00	0.00	$7.62	1,554	$6.16	23.7%	17	298	0.091	1.547	1.547
Fluorescent 4x48" 440 Watts	119	364	42.05	0.00	0.00	$42.05	11,606	$34.06	23.5%	23	2,205	0.499	11.477	11.477
Fluorescent 2x96"	120	254	29.34	0.00	0.00	$29.34	10,562	$23.77	23.4%	30	2,005	0.348	10.440	10.440
Fluorescent 4x96"	150	613	70.82	0.00	0.00	$70.82	17,847	$57.34	23.5%	21	3,397	0.840	17.640	17.640
							42,243			92	8,033			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30	4.46	0.00	0.00	$4.46	107	$3.62	23.2%	2	20	0.091	0.182	
Fluorescent 4x48" 440 Watts	311	166	24.70	0.00	0.00	$24.70	1,482	$20.02	23.4%	5	281	0.499	2.495	
Fluorescent 2x72" 300 Watts	312	116	17.26	0.00	0.00	$17.26	207	$13.99	23.4%	1	39	0.348	0.348	
Fluorescent 4x72" 600 Watts	313	222	33.03	0.00	0.00	$33.03	0	$26.72	23.6%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47	6.99	0.00	0.00	$6.99	2,097	$5.65	23.7%	25	402	0.142	3.550	
Fluorescent 1x72" 150 Watts	315	60	8.93	0.00	0.00	$8.93	0	$7.23	23.5%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280	41.66	0.00	0.00	$41.66	37,994	$33.74	23.5%	76	7,223	0.841	63.916	
							41,887			109	7,965			

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60	8.93	12.74	5.72	$27.39	16,215	$25.30	8.2%	49	1,235	0.180	8.882	
Low Pressure Sodium 180 Watts	131	80	11.90	12.74	8.23	$32.86	178,063	$30.97	6.1%	452	10,258	0.240	108.367	
Low Pressure Sodium 90 Watts	132	45	6.70	12.74	5.72	$25.16	0	$23.48	7.1%	0	0	0.135	0.000	
Low Pressure Sodium 180 Watts E&M	231	80	11.90	12.74	0.00	$24.64	11,530	$20.59	19.7%	39	1,895	0.240	9.360	
Low Pressure Sodium 180 Watts E/O	331	80	11.90	0.00	0.00	$11.90	5,284	$9.64	23.4%	37	1,003	0.240	8.880	
							211,091			577	14,391			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100	14.88	4.25	3.23	$22.36	1,078,319	$19.59	14.1%	4,019	133,609	0.300	1,205.721	
High Pressure Sodium 400 Watts	122	150	22.32	4.25	3.35	$29.91	972,387	$25.75	16.1%	2,709	135,134	0.450	1,219.128	
High Pressure Sodium 70 Watts	123	32	4.76	4.25	3.05	$12.05	4,844,431	$11.14	8.2%	33,496	368,274	0.096	3,215.614	
High Pressure Sodium 100 Watts	124	45	6.70	4.25	3.07	$14.02	6,795,488	$12.74	10.0%	40,402	620,069	0.135	5,454.262	
High Pressure Sodium 150 Watts	125	65	9.67	4.25	3.24	$17.16	1,004,512	$15.38	11.6%	4,879	104,106	0.195	951.464	
HP Sodium 100 Watts - Cont. Oper.	126	99	11.44	8.49	3.07	$23.00	4,140	$20.22	13.8%	15	501	0.135	2.025	2.025
High Pressure Sodium 250 Watts	221	100	14.88	4.25	0.00	$19.13	39,245	$15.70	21.8%	171	7,031	0.300	51.300	
High Pressure Sodium 70 Watts	222	32	4.76	4.25	0.00	$9.01	27,880	$7.49	20.2%	258	4,695	0.096	24.768	
High Pressure Sodium 100 Watts	223	45	6.70	4.25	0.00	$10.95	17,731	$9.06	20.8%	135	3,056	0.135	18.225	
High Pressure Sodium 150 Watts	224	65	9.67	4.25	0.00	$13.92	38,406	$11.48	21.2%	230	6,725	0.195	44.850	
High Pressure Sodium 250 Watts	321	100	14.88	0.00	0.00	$14.88	172,132	$12.05	23.5%	964	32,737	0.300	289.200	
High Pressure Sodium 70 Watts	322	32	4.76	0.00	0.00	$4.76	341,463	$3.84	24.0%	5,978	65,997	0.096	573.888	
High Pressure Sodium 100 Watts	323	45	6.70	0.00	0.00	$6.70	191,111	$5.41	23.8%	2,377	36,796	0.135	320.895	
High Pressure Sodium 150 Watts	324	65	9.67	0.00	0.00	$9.67	14,505	$7.83	23.5%	125	2,760	0.195	24.375	
High Pressure Sodium 400 Watts	326	150	22.32	0.00	0.00	$22.32	23,838	$18.07	23.5%	89	4,539	0.450	40.050	
High Pressure Sodium 500 Watts	327	183	27.23	0.00	0.00	$27.23	980	$22.05	23.5%	3	186	0.550	1.650	
High Pressure Sodium 1000 Watts	328	363	54.01	0.00	0.00	$54.01	9,074	$43.74	23.5%	14	1,725	1.090	15.260	
High Pressure Sodium 1500 Watts	329	500	74.39	0.00	0.00	$74.39	893	$60.23	23.5%	1	170	1.090	1.090	
							15,576,535			95,865	1,527,940			

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150	22.32	6.79	3.80	$32.92	446,060	$28.54	15.3%	1,129	59,312	0.450	508.179	
Metallic Arc 1000 Watts	141	360	53.56	10.19	5.50	$69.25	815,207	$58.97	17.4%	981	121,065	1.080	1,059.480	
Metallic Arc 250 Watts	142	100	14.88	10.19	3.75	$28.82	32,096	$25.36	13.6%	93	3,844	0.300	27.847	
Metallic Arc 150 Watts	143	67	9.97	10.19	3.75	$23.91	1,147	$21.37	11.8%	4	121	0.200	*0.800*	
Metallic Arc 100 Watts	144	50	7.44	10.19	3.75	$21.38	1,672	$19.33	10.6%	7	160	0.150	0.978	
Metallic Arc 1000 Watts	341	360	53.56	0	0	$53.56	14,140	$43.37	23.5%	22	2,690	1.080	23.760	
Metallic Arc 400 Watts	342	150	22.32	0	0	$22.32	42,587	$18.07	23.5%	159	8,109	0.450	71.550	
Metallic Arc 250 Watts	343	100	14.88	0	0	$14.88	14,999	$12.05	23.5%	84	2,853	0.300	25.200	
Metallic Arc 175 Watts	344	75	11.16	0	0	$11.16	14,999	$9.03	23.6%	112	2,863	0.225	25.200	
Metallic Arc 150 Watts	345	67	9.97	0	0	$9.97	2,393	$8.06	23.7%	20	458	0.200	4.000	
Metallic Arc 100 Watts	346	50	7.44	0	0	$7.44	0	$6.02	23.6%	0	0	0.150	0.000	
							1,385,300			2,611	201,475			
Light Emitting Diode - Traffic Lights														
Light Emitting Diode 4.6 Watts	530	3	0.36	0	0	$0.36	0	$0.29	24.1%		0		0.000	
Light Emitting Diode 7.5 Watts	531	5	0.61	0	0	$0.61	0	$0.49	24.5%		0		0.000	
							0							
Light Emitting Diode (Energy Only)														
Lighting Emitting Diode 44 Watts	532	15	2.23	0	0	$2.23	46,348	$1.81	23.2%	1,732	8,729	0.440	762.080	
Lighting Emitting Diode 66 Watts	533	22	3.27	0	0	$3.27	5,415	$2.65	23.4%	138	1,027	0.660	91.080	
Lighting Emitting Diode 88 Watts	534	29	4.31	0	0	$4.31	26,532	$3.49	23.5%	513	5,048	0.880	451.440	
Lighting Emitting Diode 92 Watts	535	31	4.61	0	0	$4.61	0	$3.73	23.6%	0	0	0.920	0.000	
Lighting Emitting Diode 105 Watts	536	35	5.21	0	0	$5.21	0	$4.22	23.5%	0	0	0.105	0.000	
Lighting Emitting Diode 170 Watts	537	57	8.48	0	0	$8.48	0	$6.87	23.4%	0	0	0.170	0.000	
Lighting Emitting Diode 110 Watts	539	37	5.50	0	0	$5.50	172,194	$4.46	23.3%	2,609	32,560	0.110	286.990	
Lighting Emitting Diode 65 Watts	540	22	3.27	0	0	$3.27	18,207	$2.65	23.4%	464	3,452	0.650	301.600	
Lighting Emitting Diode 55 Watts	541	18	2.68	0	0	$2.68	23,670	2.17	23.5%	736	4,504	0.550	404.800	
Lighting Emitting Diode 83 Watts	542	28	4.17	0	0	$4.17	51,992	3.37	23.7%	1,039	9,974	0.830	862.370	
Lighting Emitting Diode 48 Watts	543	16	2.38	0	0	$2.38	2,056	1.93	23.3%	72	389	0.830	59.760	
Lighting Emitting Diode 72 Watts	544	24	3.57	0	0	$3.57	13,195	2.89	23.5%	308	2,513	0.830	255.640	
							359,610			7,611				

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Light Emitting Diode (Energy & Capital														
LED A1	615	15	2.23	0	9.82	$12.05	803,024	8.65	39.2%	5,555	226,262	0.830	4,610.728	
LED A2	616	18	2.68	0	9.82	$12.50	238,111	9.04	38.2%	1,588	65,818	0.830	1,317.933	
LED A4	617	25	3.72	0	9.82	$13.54	61,618	9.97	35.7%	379	16,224	0.830	314.848	
LED A3	618	29	4.31	0	9.82	$14.13	1,378	10.49	34.6%	8	354	0.830	6.745	
LED B1	619	22	3.27	0	9.82	$13.09	1,045,305	11.75	11.4%	6,656	106,946	0.830	5,524.856	
LED C1	620	29	4.31	0	9.82	$14.13	173,599	13.82	2.2%	1,024	3,716	0.830	849.988	
LED C3	621	37	5.50	0	9.82	$15.32	142,287	14.88	2.9%	774	4,017	0.830	642.549	
LED C2	622	58	8.63	0	9.82	$18.45	150,050	17.65	4.5%	678	6,446	0.830	562.628	
							2,615,372			16,663				
TOTALS							**$23,602,666**			**139,057**			**35,794.276**	**44.667**
										122,394				

Non LED	**114,783**
LED	**24,274**
Total	**139,057**
Non LED	
Energy Only	103,386
Maintenance	957
Capital	10,440
Total	114,783
LED	
Energy Only	7,611
Capital	16,663
Total	24,274
Grand Total	139,057

Street / Crosswalk Lighting Study

2014 Schedules

SCHEDULE 10

2013 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)

Count = 105

Note 1 - Red highligted P&E charges relate to calculated rounding differences using Misc. Small Loads Tariff.
Note 2 - Incandescent rates were set at 250W and 400W Mercury Vapour

Miscellaneous Small Loads Rate		
Demand Charge	$/kW	**9.339**
Block 1 Energy		
Base cost of fuel	¢/kWh	5.087
Non-fuel	¢/kWh	5.593
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 1 (first 200kWh *	¢/kWh	**10.680**
Block 2 Energy		
Base cost of fuel	¢/kWh	5.087
Non-fuel	¢/kWh	2.004
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 2	¢/kWh	**7.091**

Calculation of Power & Energy Rate :
Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

Photocell Operation (4000 burning hours per year)			
Demand Charge $/kW (annual)		11.534	$138.41
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.13191	316.58
2nd Block : All additional (annual)	1,600	0.08758	140.13
			$595.12
Rate per kW.h	4,000		**$0.1487808**
Continuous Burning (8760 burning hours per year)			
Demand Charge $/kW (annual)		11.534	$138.41
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.13191	316.58
2nd Block : All additional (annual)	6,360	0.08758	557.01
			$1,012.00
Rate per kW.h	8,760		**$0.1155256**

SCHEDULE 1

2014 STREET / CROSSWALK LIGHTING STUDY

Rate Code	Description	MARCH 2013 (Quantity) Full Charge	MARCH 2013 (Quantity) Energy & Maint	MARCH 2013 (Quantity) Energy Only	MARCH 2013 (Quantity) Total	FORECAST 2014 (Quantity) Full Charge	FORECAST 2014 (Quantity) Energy & Maint	FORECAST 2014 (Quantity) Energy Only	FORECAST 2014 (Quantity) Total	Full Charge Adj. for LED Conv.
001/003	Incandescent < 300 Watts	27	0	7	34	27	0	7	34	27
002	Incandescent > 300 Watts	2	0	0	2	2	0	0	2	2
		29	0	7	36	29	0	7	36	29
100	Mercury Vapour 100 Watts	216	0	0	272	216	0	0	216	189
101/201/301	Mercury Vapour 125 Watts	8,921	7	11	11,240	8921	7	11	8939	7778
102/202/302	Mercury Vapour 175 Watts	2,133	21	157	2,861	2133	21	157	2311	1859
103/203/303	Mercury Vapour 250 Watts	821	35	54	1,122	821	35	54	910	716
104/204/304	Mercury Vapour 400 Watts	798	9	15	1,028	798	9	15	822	696
105/205/305	Mercury Vapour 700 Watts	11	0	1	12	11	0	1	12	11
106/206/306	Mercury Vapour 1000 Watts	86	22	7	115	86	22	7	115	86
107	Mercury Vapour 250 Watt Cont. Oper.	3	0	0	3	3	0	0	3	3
		12,989	94	245	16,653	12989	94	245	13328	11338
110	Fluorescent 2x24" 70 Watts	897	0	0	897	897	0	0	897	897
111	Fluorescent 2x48" 220 Watts	114	0	0	114	114	0	0	114	114
112	Fluorescent 2x72" 300 Watts	67	0	0	67	67	0	0	67	67
113/213	Fluorescent 4x72" 600 Watts	15	0	0	15	15	0	0	15	15
114/214	Fluorescent 1x96" 110 Watts	5	26	0	31	5	26	0	31	5
115/215	Fluorescent 1x72" 150 Watts	1	3	0	4	1	3	0	4	1
116	Fluorescent 4x48" 440 Watts	2	0	0	2	2	0	0	2	2
217	Fluorescent 1x48"	0	1	0	1	0	1	0	1	0
218	Fluorescent 2x48"	0	0	0	0	0	0	0	0	0
330	Fluorescent 4x35"	0	0	2	2	0	0	2	2	0
350	Fluorescent 4x96"	0	0	76	76	0	0	76	76	0
		1,101	30	78	1,209	1101	30	78	1209	1,101
117	Fluorescent Crosswalk Cont. 4x72"	0	0	1	1	0	0	1	1	0
118	Fluorescent Crosswalk Cont. 2x24"	0	0	17	17	0	0	17	17	0
119	Fluorescent Crosswalk Cont. 4x48"	0	0	23	23	0	0	23	23	0
120	Fluorescent Crosswalk Cont. 2x96"	0	0	30	30	0	0	30	30	0
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21	0	0	21	21	0
		0	0	92	92	0	0	92	92	0
310	Fluorescent Crosswalk 2x24"	0	0	2	2	0	0	2	2	0
311	Fluorescent Crosswalk 4x48"	0	0	5	5	0	0	5	5	0
312	Fluorescent Crosswalk 2x72"	0	0	1	1	0	0	1	1	0
313	Fluorescent Crosswalk 4x72"	0	0	0	0	0	0	0	0	0
314	Fluorescent Crosswalk 1x96"	0	0	25	25	0	0	25	25	0
315	Fluorescent Crosswalk 1x72"	0	0	0	0	0	0	0	0	0
		0	0	33	33	0	0	33	33	0

SCHEDULE 1

2014 STREET / CROSSWALK LIGHTING STUDY

		MARCH 2013 (Quantity)				FORECAST 2014 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
121/221/321	High Pressure Sodium 250 Watts	3,721	171	964	5,816	3721	171	964	4856	3,244
122/326	High Pressure Sodium 400 Watts	2,508	0	89	3,244	2508	0	89	2597	2,187
123/222/322	High Pressure Sodium 70 Watts	31,013	258	5,978	45,249	31013	258	5978	37249	27,040
124/223/323	High Pressure Sodium 100 Watts	37,406	135	2,377	49,570	37406	135	2377	39918	32,612
125/224/324	High Pressure Sodium 150 Watts	4,518	230	125	6,038	4518	230	125	4873	3,939
126	HP Sodium 100 Watts - Cont. Oper.	15	0	0	15	15	0	0	15	15
327	High Pressure Sodium 500 Watts	0	0	3	3	0	0	3	3	0
328	High Pressure Sodium 1000 Watts	0	0	14	14	0	0	14	14	0
329	High Pressure Sodium 1500 Watts	0	0	1	1	0	0	1	1	0
		79,181	794	9,551	109,950	79181	794	9551	89526	69,038
130	Low Pressure Sodium 135 Watts	46	0	0	58	46	0	0	46	40
131/231/331	Low Pressure Sodium 180 Watts	418	39	37	602	418	39	37	494	365
132	Low Pressure Sodium 90 Watts	0	0	0	0	0	0	0	0	0
		464	39	37	660	464	39	37	540	404
140/342	Metallic Arc 400 Watts	1,046	0	159	1,474	1046	0	159	1205	912
141/341	Metallic Arc 1000 Watts	981	0	22	1,003	981	0	22	1003	981
142/343	Metallic Arc 250 Watts	86	0	84	193	86	0	84	170	74
143	Metallic Arc 150 Watts	4	0	0	4	4	0	0	4	4
144	Metallic Arc 100 Watts	5	0	0	7	5	0	0	5	4
344	Metallic Arc 175 Watts	0	0	112	112	0	0	112	112	0
345	Metallic Arc 150 Watts	0	0	20	20	0	0	20	20	0
346	Metallic Arc 100 Watts	0	0	0	0	0	0	0	0	0
		2,121	0	397	2,813	2121	0	397	2518	1,975
532/538	LED 44 Watts	0	0	1,732	1,732	0	0	1732	1732	0
539	LED 110 Watts	0	0	2,609	2,609	0	0	2609	2609	0
533	LED 66 Watts	0	0	138	138	0	0	138	138	0
534	LED 88 Watts	0	0	513	513	0	0	513	513	0
537	LED 173 Watts	0	0	38	38					
540	LED 65 Watts	0	0	464	464	0	0	464	464	0
541	LED 55 Watts	0	0	736	736	0	0	736	736	0
542	LED 83 Watts	0	0	1,039	1,039	0	0	1039	1039	0
543	LED 48 Watts	0	0	72	72	0	0	72	72	0
544	LED 72 Watts	0	0	308	308	0	0	308	308	0
	Total	0	0	7,649	7,649	0	0	7649	7649	0
	LED A	20,572				20,572			20572	30,789
	LED B	2,608	0	0	0	2,608			2608	3,903
	LED C	983	0	0	0	983			983	1,471
	Total	24,163	0	0	0	24,163			24163	36,163
	Total	120,048	957	18,089	139,095	120,048	957	18,089	139,094	120,048

SCHEDULE 2

2014 STREET / CROSSWALK LIGHTING STUDY
CALCULATION OF MAINTENANCE COSTS BY FIXTURE TYPE

(A) Code	(B) Lamp Type	(C) Service Life (Years)	(D) Maintenance Weighting Factors	(E) # of Full Chg & Eng.+Maint. Fixtures	(F) Weighting Total	(G) Cost Per Year	(H) Cost Per Month
A	Mercury Vapour	6.000	1.0000	3,676	3,676	$63.68	$5.31
B	Mercury Vapour - 125W	4.500	1.3333	7,785	10,380	$84.90	$7.08
C	Fluorescent	3.000	2.0000	1,131	2,262	$127.35	$10.61
D	High Pressure Sodium (Note1)	6.000	1.0000	69,847	69,847	$63.68	$5.31
E	Metallic Arc 100W, 150W & 250W	2.500	2.4000	83	198	$152.82	$12.74
F	Metallic Arc 400W	3.750	1.6000	912	1,459	$101.88	$8.49
G	Metallic Arc 1000W	2.500	2.4000	981	2,354	$152.82	$12.74
H	Low Pressure Sodium	2.000	3.0000	443	1,330	$191.03	$15.92
I	LED	20.000	0.3000	0	0	$19.10	$1.59
				84,857	91,506		

Street Lighting Maint. Expenses
(from 2014 COSS, Exhibit 6A) **$5,826,697**

Annual Cost of High Pressure Sodium
($5,826,697.32 / 91505.5890121691 weighted fixtures) **$63.68**

Note 1: Maintenance weighting factors relative to High Pressure Sodium fixture, index = 1.0
Factor is: HPS service life / various fixture service lives

SCHEDULE 3

2014 STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

Gross Plant Value (including installation costs) less Retirements of Non-LED Street Lighting Equipment, 2013 Average → **Total** **$35,521,858**

Description	Unit Cost Mar/1977	Unit Cost Mar-11	Historical 11-Mar Fixtures	Average # of Fixtures ɛginning of Yɛ	Avg # of Fixtures End of Year	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	27	27	27	$1,733	
Incandescent > 300 Watts	$63.62	$79.53	2	2	2	$159	
Mercury Vapour 100 Watts	$76.55	$229.55	216	216	189	$49,664	
Mercury Vapour 125 Watts	$77.16	$204.78	8,921	8,921	7,778	$1,826,771	
Mercury Vapour 175 Watts	$85.30	$201.27	2,133	2,133	1,859	$429,217	
Mercury Vapour 250 Watts	$87.24	$291.38	821	821	716	$239,354	
Mercury Vapour 400 Watts	$107.82	$301.45	798	798	696	$240,614	
Mercury Vapour 700 Watts	$485.12	$449.78	11	11	11	$4,948	
Mercury Vapour 1000 Watts	$492.29	$579.25	86	86	86	$49,816	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$291.38	3	3	3	$874	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	897	897	897	$119,346	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	114	114	114	$18,797	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	67	67	$14,968	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	15	15	$5,507	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	5	5	$1,000	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	1	1	1	$152	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	2	2	$472	
High Pressure Sodium 70 Watts	***N/A***	$207.51	31,013	31,013	27,040	$6,435,494	
High Pressure Sodium 100 Watts	***N/A***	$210.65	37,421	37,421	32,627	$7,882,559	
High Pressure Sodium 150 Watts	***N/A***	$232.66	4,518	4,518	3,939	$1,051,088	
High Pressure Sodium 250 Watts	$156.49	$231.67	3,721	3,721	3,244	$862,095	
High Pressure Sodium 400 Watts	$173.73	$246.21	2,508	2,508	2,187	$617,586	
High Pressure Sodium 1000 Watts	***N/A***	$615.53	0	0	0	$0	
Low Pressure Sodium 90 Watts	***N/A***	$554.53	0	0	0	$0	
Low Pressure Sodium 135 Watts	$371.69	$554.53	46	46	40	$25,334	
Low Pressure Sodium 180 Watts	$226.10	$880.14	418	418	365	$367,949	
Metallic Additive 250 Watts	***N/A***	$298.33	90	90	78	$26,744	
Metallic Additive 400 Watts	$358.84	$305.76	1,046	1,046	912	$319,693	
Metallic Additive 1000 Watts	$560.49	$526.16	981	981	981	$516,159	
Metallic Additive 100 Watts	***N/A***		5	5	4	$0	
			95,885	95,885	83,885		**21,108,091**

Total # of light types being displaced by LED	93,674	93,674	
Total Installation Costs (Labour)			**$14,413,767**
Installation Costs per Fixture			**$171.83**

Escalation Factor (Incandescent)	125%
Escalation Factor (Fluorescent)	125%

Note: 2007 costs are based on stores material inventory cost as of June 2007 with the exception of Incandescent and fluorescent which have been assumed at 130% of 1977 costs.

Sample Material Cost - 100 Watt High Intensity (Pressure) Sodium :
Inventory Prices as of March 2011

Fixture, Ballast & Photocell	$124.02
Bracket Assembly (Davit)	67.32
Wire	16.71
Miscellaneous Hardware	2.60
Lamp Replacement	8.62
TOTAL	**$219.27**

SCHEDULE 4

2014 STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

	Non Led	LED
Depreciation Rate for 2013	5.33%	5.33%
# of Years	18.76	18.76
Tax Adjusted Weighted Average Cost of Capital	10.47%	9.38%
Pre-tax WACC	7.83%	7.83%
Tax-related Gross-up Depreciation factor	31.00%	31.00%
Salvage Rate (% of Depreciation)	0.00%	0.00%
Salvage Rate incl in Depr. Rate for 2013	0.00%	0.00%
# of Years	N/A	N/A

	Revenue Correction factor Non LED	LED
Simulated at current meth.	$5,988,194	$3,846,850
Total cost per COSS (and adjusted for energy)	$3,274,850	$4,340,815
Revenue Correction Factor	**0.5469**	**1.1284**

	Material Cost January 2010	Labour Cost	Total	Before Correction Factor: Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost	Correction Factor	Aligned with COSS results: Total Annual Cost	Monthly Cost	2013 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Incandescent < 300 Watts	$64.20	171.83	$236.03	$18.23	$24.71	$0.00	$42.94	0.547	$23.49	$1.96	27	492.27	667.23		1,159.50	634.11
Incandescent > 300 Watts	79.53	171.83	251.35	$19.42	$26.32	$0.00	45.73	0.547	$25.01	2.08	2	38.83	52.63		91.47	50.02
Mercury Vapour 100 Watts	229.55	171.83	401.37	$31.00	$42.02	$0.00	73.03	0.547	$39.94	3.33	189	5,848.73	7,927.38		13,776.11	7,533.94
Mercury Vapour 125 Watts	204.78	171.83	376.61	$29.09	$39.43	$0.00	68.52	0.547	$37.47	3.12	7,778	226,270.05	306,687.19		532,957.23	291,466.00
Mercury Vapour 175 Watts	201.27	171.83	373.10	$28.82	$39.06	$0.00	67.88	0.547	$37.12	3.09	1,859	53,587.24	72,632.33		126,219.58	69,027.52
Mercury Vapour 250 Watts	291.38	171.83	463.20	$35.78	$48.50	$0.00	84.28	0.547	$46.09	3.84	716	25,627.23	34,735.23		60,362.45	33,011.28
Mercury Vapour 400 Watts	301.45	171.83	473.28	$36.56	$49.55	$0.00	86.11	0.547	$47.09	3.92	696	25,442.77	34,485.21		59,927.98	32,773.68
Mercury Vapour 700 Watts	449.78	171.83	621.61	$48.02	$65.08	$0.00	113.10	0.547	$61.85	5.15	11	528.19	715.91		1,244.09	680.38
Mercury Vapour 1000 Watts	579.25	171.83	751.08	$58.02	$78.64	$0.00	136.66	0.547	$74.74	6.23	86	4,989.57	6,762.88		11,752.45	6,427.23
Mercury Vapour 250 Watt Cont. Oper.	291.38	171.83	463.20	$35.78	$48.50	$0.00	84.28	0.547	$46.09	3.84	3	107.34	145.49		252.83	138.27
Fluorescent 2x24" 70 Watts	133.05	171.83	304.88	$23.55	$31.92	$0.00	55.47	0.547	$30.34	2.53	897	21,124.97	28,632.85		49,757.82	27,211.77
Fluorescent 2x48" 220 Watts	164.89	171.83	336.72	$26.01	$35.25	$0.00	61.26	0.547	$33.50	2.79	114	2,965.14	4,018.96		6,984.11	3,819.50
Fluorescent 2x72" 300 Watts	223.40	171.83	395.23	$30.53	$41.38	$0.00	71.91	0.547	$39.33	3.28	67	2,045.50	2,772.48		4,817.98	2,634.88
Fluorescent 4x72" 600 Watts	367.15	171.83	538.98	$41.63	$56.43	$0.00	98.07	0.547	$53.63	4.47	15	624.51	846.46		1,470.98	804.45
Fluorescent 1x96" 110 Watts	200.00	171.83	371.83	$28.72	$38.93	$0.00	67.65	0.547	$37.00	3.08	5	143.61	194.65		338.26	184.99
Fluorescent 1x72" 150 Watts	151.53	171.83	323.35	$24.98	$33.86	$0.00	58.83	0.547	$32.17	2.68	1	24.98	33.86		58.83	32.17
Fluorescent 4x48" 440 Watts	236.14	171.83	407.97	$31.51	$42.71	$0.00	74.23	0.547	$40.59	3.38	2	63.03	85.43		148.46	81.19
High Pressure Sodium 70 Watts	207.51	171.83	379.34	$29.30	$39.72	$0.00	69.02	0.547	$37.75	3.15	27,040	792,341.06	1,073,941.75		1,866,282.81	1,020,640.98
High Pressure Sodium 100 Watts	210.65	171.83	382.47	$29.54	$40.04	$0.00	69.59	0.547	$38.06	3.17	32,627	963,959.25	1,306,553.62		2,270,512.86	1,241,708.09
High Pressure Sodium 150 Watts	232.66	171.83	404.49	$31.25	$42.35	$0.00	73.60	0.547	$40.25	3.35	3,939	123,072.73	166,813.19		289,885.92	158,534.09
High Pressure Sodium 250 Watts	231.67	171.83	403.50	$31.17	$42.25	$0.00	73.42	0.547	$40.15	3.35	3,244	101,126.64	137,067.39		238,194.03	130,264.60
High Pressure Sodium 400 Watts	246.21	171.83	418.04	$32.29	$43.77	$0.00	76.06	0.547	$41.60	3.47	2,187	70,623.39	95,723.18		166,346.57	90,972.35
High Pressure Sodium 1000 Watts	615.53	171.83	787.36	$60.82	$82.44	$0.00	143.26	0.547	$78.35	6.53	-	-	-		-	-
Low Pressure Sodium 90 Watts	554.53	171.83	726.36	$56.11	$76.05	$0.00	132.16	0.547	$72.28	6.02	-	-	-		-	-
Low Pressure Sodium 135 Watts	554.53	171.83	726.36	$56.11	$76.05	$0.00	132.16	0.547	$72.28	6.02	40	2,234.93	3,029.23		5,264.16	2,878.89
Low Pressure Sodium 180 Watts	880.14	171.83	1,051.97	$81.26	$110.14	$0.00	191.40	0.547	$104.67	8.72	365	29,619.72	40,146.67		69,766.40	38,154.16
Metallic Arc 250 Watts	298.33	171.83	470.15	$36.32	$49.23	$0.00	85.54	0.547	$46.78	3.90	78	2,838.65	3,847.51		6,686.16	3,656.56
Metallic Arc 400 Watts	305.76	171.83	477.59	$36.89	$50.00	$0.00	86.90	0.547	$47.52	3.96	912	33,631.79	45,584.64		79,216.43	43,322.23
Metallic Arc 1000 Watts	$526.16	171.83	$697.98	$53.92	$73.08	$0.00	$127.00	0.547	$69.45	$5.79	981	52,892.29	71,690.39		124,582.68	68,132.33
Metallic Additive 100 Watts	$0.00	171.83	$171.83	$13.27	$17.99	$0.00	$31.26	0.547	$17.10	$1.42	4	57.86	78.43		136.29	74.54
Total											**83,885**	**$2,542,322**	**$3,445,872**		**$5,988,194**	**$3,274,850**

	Material Cost January 2010	Labour Cost	Total	Before Correction Factor: Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost	Correction Factor	Aligned with COSS results: Total Annual Cost	Monthly Cost	2013 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
LED A	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	1.128	$120.03	10.00	30,789	1,716,622.46	2,084,488.53	(525,943.92)	3,275,167.07	3,695,723.86
LED B	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	1.128	$120.03	10.00	3,903	217,612.68	264,246.31	(66,672.82)	415,186.16	468,499.28
LED C	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	1.128	$120.03	10.00	1,471	82,025.13	99,602.82	(25,131.10)	156,496.85	176,592.26
											36,163	**$2,016,260**	**$2,448,338**	**-$617,748**	**$3,846,850**	**$4,340,815**

SCHEDULE 5

2014 STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Rate by Components
For 2014 Street Light Rates

a) Weighted Average Cost of Capital - Pretax				**Non-LED**		**LED**
	Proportion	Cost	Extended		Extended	
ST Debt	6.7%	6.1%	0.4%	0.41%	0.4%	0.41%
LT Debt	52.1%	7.2%	3.8%	3.75%	3.8%	3.75%
Preferred	3.7%	6.0%	0.2%	0.22%	0.2%	0.22%
Common	37.5%	9.2%	3.5%	3.45%	3.5%	3.45%
	100.0%		7.8%		7.8%	
WACC - pretax cost				7.83%		7.83%
b) Additional income tax for common equity						
Extended equity cost			3.45%		3.45%	
Effective tax rate (excluding surtax)			31.0%		31.0%	
Income tax			1.55%		1.55%	
WACC - equity tax cost				1.55%		1.55%
c) Large Corporations Tax						
Provincial capital tax (2014)			0.000%		0.000%	
Federal capital tax (2014)			0.000%		0.000%	
Ave. NBV - Street Lighting			$10,251		$24,256	
Ave. NBV - Assigned GP Plt.			718.137		1,699.360	
Ave. Deferred Chgs & W/C			710.082		1,680.297	
NPV - Total Street Lighting			$11,678.828		$27,636.116	
Provincial capital tax			$0.000		$0.000	
Federal capital tax			$0.000		$0.000	
Total			$0.000		$0.000	
Percentage of NBV			0.00%		0.00%	
WACC - Large Corporations Tax				0.00%		0.00%
d) Grants in Lieu of Property Tax						
Total 2014 Forecasted Expense			$38.400		N/A	
St. Lgts. % of Total Electric Plant			331.58%		N/A	
St. Lgts. Allocated Amount			$127.327		N/A	
Percentage of NBV			1.09%		N/A	
WACC - Grants in Lieu of Property Tax				1.09%		0.00%
Total WACC - Interest / Carrying Cost				**10.47%**		**9.38%**

SCHEDULE 5A

2014 STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components

For 2014 Street Light Rates

Depreciation Rate	**5.33%**
Salvage Rate	**0.00%**
Salvage Incl. in Depreciation Rate	**0.00%**
Gross-up factor for tax purposes (LED only)	**31.00%**

		Non LED	Non LED	LED	Year 2
Gross Plant Value (YA)			$35,522	$25,586	
Net Plant Value (YA)			$10,251	$24,256	6,749
a) Weighted Average Cost of Capital - Pretax					
	ST Debt	0.41%		99	27
	LT Debt	3.75%		910	253
	Subtotal		*400*	*1,009*	*281*
	Preferred	0.22%	$22.8	54	15
	Common	3.45%	$344.5	837	233
	WACC - pretax cost	7.83%	$766.9	$1,899	$529
b) Additional income tax for common equity					
	WACC - equity tax cost	1.55%		376	105
c) Large Corporations Tax					
	WACC - Large Corporations Tax	0.00%		0	0
Subtotal			*$161.2*	*376*	*105*
d) Grants in Lieu of Property Tax					
	WACC - Grants in Lieu of Property Tax	1.09%	$106.5	0	74
Subtotal Financing Expense		**10.47%**	**$1,034.5**	**$2,275.4**	**$706.7**
Depreciation Expense			**$2,240.326**	**$1,364**	**$0.0**
Gross up for Tax Purposes				**$612.7**	**$0.0**
Total Depreciation Expense including Gross up for Tax Purposes			**$2,240.3**	**$1,976.4**	**$0.0**
CCA			**$0.0**	**-$617.7**	**$0.0**
TOTAL CAPITAL COST EXPENSE			**$3,274.9**	**$3,634.101**	**$706.715**

SCHEDULE 6

2014 STREET / CROSSWALK LIGHTING STUDY
AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

Light Type Street Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Incandescent < 300 Watts	$51.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Incandescent > 300 Watts	$63.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mercury Vapour 100 Watts	$229.55	$122.41	$15.99	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 125 Watts	$204.78	$102.95	$10.68	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 175 Watts	$201.27	$102.95	$7.17	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 250 Watts	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 400 Watts	$301.45	$198.75	$8.98	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 700 Watts	$449.78	$318.97	$37.10	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 1000 Watts	$579.25	$439.19	$46.35	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 250 Watt Cont. Oper.	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Fluorescent 2x24" 70 Watts	$106.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x48" 220 Watts	$131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x72" 300 Watts	$178.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x72" 600 Watts	$293.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x96" 110 Watts	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x72" 150 Watts	$121.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x48" 440 Watts	$188.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High Pressure Sodium 70W	$207.51	$120.88	$8.81	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 100W	$210.65	$124.02	$8.62	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 150W	$232.66	$146.03	$8.67	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 250 Watts	$231.67	$142.48	$10.59	$4.52	$69.88	$16.71	$1.09	$1.51
High Pressure Sodium 400 Watts	$246.21	$157.02	$13.19	$4.52	$69.88	$16.71	$1.09	$1.51
Low Pressure Sodium 90W	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 135 Watts	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 180 Watts	$880.14	$788.99	$54.77	$4.52	$67.32	$16.71	$1.09	$1.51
Metallic Additive 250W	$298.33	$190.30	$18.83	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 400 Watts	$305.76	$201.63	$14.93	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 1000 Watts	$526.16	$405.65	$31.31	$0.00	$69.88	$16.71	$1.09	$1.51
LED A	$420.00							
LED B	$420.00							
LED C	$420.00							

Light Type Flood Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Mercury Vapour 175 Watts	$67.32	$53.03	$7.17	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 250 Watts	$412.88	$397.90	$7.86	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 400 Watts	$297.27	$281.17	$8.98	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 1000 Watts	$507.90	$439.19	$46.35	$19.77	$0.00	$0.00	$1.09	$1.51
HIS 150W	$215.75	$183.39	$25.23	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 250 Watts	$202.12	$184.41	$10.59	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 400 Watts	$215.26	$194.95	$13.19	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Additive 250W	$216.25	$190.30	$18.83	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 400 Watts	$223.69	$201.63	$14.93	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 1000 Watts	$459.33	$405.65	$31.31	$19.77	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 70W HPS	$197.77	$195.17	$8.81	$4.52	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 100W HPS	$143.10	$140.50	$8.62	$4.52	$0.00	$0.00	$1.09	$1.51

SCHEDULE 7

2014 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0000386440	LAMP FLUORESCENT 40W 48	1.35	
0000386450	LAMP FLUORESCENT 40W 48	1.36	
0000386700	LAMP FLUORESCENT 75W 96	3.49	
0000386710	LAMP FLUORESCENT 205W	3.95	
0000387070	LAMP FLUORESCENT 35W 24	4.19	
0000387190	LAMP FLUORESCENT 60W 48	3.19	
0000387360	LAMP FLUORESCENT 85W 72	6.54	
0000388000	LAMP 100 WATT M.V.	15.99	
0000388180	LAMP 125 WATT M.V.	10.68	
0000388330	LAMP 175 WATT M.V.	7.17	
0000388500	LAMP 250 WATT M.V.	7.86	
0000388660	LAMP 400 WATT M.V.	8.98	
0000388770	LAMP 700 WATT M.V.	37.10	
0000388980	LAMP 1000 WATT MV	46.35	
0000388990	LAMP 70 WATT H.P.S.	8.81	
0000389000	LAMP 100 WATT H.P.S.	8.62	
0000389030	LAMP 135 WATT L.P.S.	44.00	
0000389040	LAMP 150 WATT HPS 100V	25.23	
0000389060	LAMP 150 WATT H.P.S.55V	8.67	
0000389090	LAMP 180 WATT L.P.S.	54.77	
0000389250	LAMP 250 WATT H.P.S.	10.59	
0000389400	LAMP 400 WATT H.P.S.	13.19	
0000389450	LAMP 1000W HPS	60.32	
0000389700	LAMP HALIDE 250W	18.83	
0000389770	LAMP HALIDE 400W	14.93	
0000389810	LAMP HALIDE 1000W	31.31	
0000389900	LAMP STREET LITE SIGNAL	2.21	
0002103270	CONDUIT FLEX BLK 1/2"	4.36	
0050091540	BOLT LAG 1/2"X 4" GALV	0.46	
0050103120	BOLT MACHINE 5/8" X 12"	1.05	
0054223510	CRIMPIT #2/0- #8 WR139	0.55	
0057151000	BRACKET 10'L	101.45	
0057152040	BRACKET 1 1/4"X4' FIXED	60.02	
0057152220	BRACKET 4'X 2' 16" TEN	27.46	
0057154060	BRACKET 1 1/4"X6' LOWER	67.32	
0057155060	BRACKET SWIVEL 1 1/4 X6	18.91	
0057155720	BRACKET TAPERED 6' X 2"	48.90	
0057155723	BRACKET TAPERED 8'	87.05	
0057155725	BRACKET TAPERED 2"X10'	106.44	
0057156020	BRACKET LOWER 2" X 6'	69.88	
0057156080	BRACKET FIXED 2" X 8'	87.48	
0057157010	BRACKET TAPERED 12'L	173.80	
0057158140	PLATE POLE ST LITE 1 1/	9.46	
0057158220	PLATE POLE ST LIGHT 2"	26.24	

SCHEDULE 7

2014 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057350350	LUMINAIRE LPS 135W	463.38	
0057350720	LUM LPS 180W 120/240/347 V	788.99	R04B
0057350750	LUMINAIRE LPS 180W 240V	493.30	XX
0057350800	LUMINAIRE LPS 180W 347V	780.20	XX
0057350830	LUMINAIRE HPS 70W POLY	73.33	XX
0057350835	LUM. 70W POLY C/W LAMP	99.23	XX
0057350836	LUM 70W POLY ALUM.ALLOY	97.70	XX
0057350837	LUMINAIRE 70W HPS CWA ACRY	120.88	C01A
0057350850	LUMINAIRE HPS 70W GLASS	69.32	XX
0057350855	LUM. 70W GLASS C/W LAMP	97.68	C03A
0057350856	LUM 70W GLASS AL. ALLOY	99.37	M12D
0057350857	LUM. 70W GLASS CWI BAL.	120.32	M08A
0057350860	LUM 100W HPS POLY	75.00	XX
0057350865	LUM. 100W POLY C/W LAMP	100.21	XX
0057350866	LUMINAIRE 100W ACRYLIC HPS	124.02	C07A
0057350867	LUM 100W POLY AL. ALLOY	98.37	XX
0057350875	LUM. 100W GLASS C/WLAMP	98.76	XX
0057350877	LUM. 100W GLASS CWI BAL	135.75	XX
0057350880	LUMINAIRE HPS 150W GLAS	82.27	XX
0057350885	LUM. 150W GLASS C/WLAMP	100.95	XX
0057350886	LUMINAIRE 150W HPS CWI GLAS	146.03	M05A
0057350887	LUM. 150W HPS 240V GLAS	150.88	C09A
0057350890	LUMINAIRE HPS 150W POLY	79.24	XX
0057350895	LUM. 150W POLY C/W LAMP	102.95	XX
0057351315	LUMINAIRE 250W HPS CWI GLAS	142.48	C07A
0057351400	LUMINAIRE 250W HPS CWI 347V	160.68	C05A
0057351710	LUMINAIRE HPS 400W GLAS	109.60	XX
0057351715	LUMINAIRE 400W HPS CWI 120/2	157.02	M12A
0057351720	LUMINAIRE HPS 400W 240V	204.30	XX
0057351730	LUMINAIRE HPS 400W 347V	196.00	XX
0057351760	LUMINAIRE 400W 600V HPS CWI	172.33	M12A
0057353330	LUMINAIRE MTL-HLDE 400W	281.54	XX
0057353500	LUMINAIRE HALIDE 1000 W	300.00	XX
0057353550	LUMINAIRE HALIDE 1000 W	294.79	T01C
0057400920	AREA LIGHT MV 125 W	107.76	XX
0057401200	LUMINAIRES 70W H-P.S.	107.80	D14B
0057401205	DUSK-T-DAWN 70W HPS CWA	195.17	D08B
0057402020	AREA LIGHT MV 175 W	92.88	XX
0057402100	LUMINAIRES 100W H.P.S.	106.37	XX
0057402105	DUSK-T-DAWN 100W HPS CWA	140.50	C15A
0057402150	FLOODLIGHT 150W HPS CWI	183.39	C17A
0057402240	FLOODLIGHT M.V. 175W	53.03	
0057403330	FLOODLIGHT M V 250 W	397.90	XX
0057403500	FLOODLIGHT 250W HPS CWI	184.41	

SCHEDULE 7

2014 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057404050	FLOODLIGHT M V 400 W	281.17	XX
0057404600	FLOODLIGHT 400W HPS CWI	194.95	C11A
0057408250	FLOODLIGHT MTL HAL.250W	190.30	D05B
0057408500	FLOODLIGHT 400W MTL-HAL CW	201.63	D03A
0057409000	FLOODLIGHT 1000W MH CWI	405.65	
0057409380	FLOODLIGHT M V 1000 W	439.19	XX
0057600450	BRACKET & ADAPTORS	9.40	
0057601010	CAP SHORTING TWIST LOCK	4.87	
0057601200	CONTROL 120 V PHOTO	7.05	
0057601400	CONTROL ELECT 120V PHOTOC	4.52	
0057602000	PHOTO CONTROL 120V HD	19.77	
0057602400	CONTROL 240V ELECT PHOTOC	10.96	
0057602960	GUARD WIRE FOR ST-LITE	50.44	
0057603800	REFRACTOR GLASS	32.60	
0057603900	REFRACTORS POLYCARBON #	0.00	
0057604020	REFRACTOR POLY LU B2214	48.03	
0057604050	REFRACTOR POLY LU B2217	73.74	
0057604080	REFRACTOR POLYCARBON #9	21.07	
0057604170	REFRACTOR GLASS	66.37	
0057604200	REFRACTOR ACRYLIC VB15	40.70	
0057604210	REFRACTOR POLY LUM VB15	78.68	
0057604220	REFRACTOR AREA LIGHT	18.99	
0057604240	REFRACTOR GLASS OV15	16.00	
0057604250	REFRACTOR POLY LUM 0V15	24.00	
0057604255	REFRACTOR STREETLIGHT OV	18.12	
0057604270	REFRACTOR GLASS OV25	25.89	
0057604280	REFRACTOR POLY OV25	92.87	
0057604300	REFRACTOR GLASS OV50	17.50	
0057605800	REDUCER LAMPHOLDER,	6.25	
0057606100	REFRACTOR 125 W M V	34.36	
0057606500	REFRACTOR FOR SODIUM	71.31	
0057606550	REFRACTOR FOR SODIUM	88.62	
0057606700	REFRACTOR 250 W M V	38.69	
0057606950	REFRACTOR 400 W M V	33.01	
0057607300	RELAY 30 AMP 110 V MURC	33.89	
0057607330	RELAY 30 AMP 125 V	140.04	
0057607400	RELAY 60 AMP 115 V	214.85	
0057607440	RELAY 60 AMP 250 V	191.29	
0057608690	STARTERS HPS LUMINAIRES	31.63	
0057608700	STARTER FOR HPS 70-150W	40.95	
0057608703	STARTER FOR HPS 55V	41.17	
0057608710	STARTER FOR SODIUM	40.41	
0057608713	STARTER KIT HPS 55V 70/	31.75	
0057608720	STARTER FOR HPS 150-400	40.76	

SCHEDULE 7

2014 STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057608722	STARTER FOR HPS 100V	36.35	
0057608730	STARTER FOR SODIUM	48.16	
0065734220	CABLE CU ST-LITE 2C #12	1.03	

SCHEDULE 8

2014 STREET / CROSSWALK LIGHTING STUDY
LAMP LIFE ANALYSIS
September 2005

Assumptions: Total annual photocell operating time is based on 4,000 hours per year or 333 hours per month.
All Average Rated Life Spans are as indicated in the IES Lighting Handbook, 1981 Edition
(IES = Illuminating Engineering Society)

Lamp Type	Average Life (Hrs)	Burning Hours per Year	Service Life (Years)	Life Relative to 100W HPS	Replacements Relative to 100W HPS
Incandescent	2500	4000	0.6	0.10	9.60
Flourescent (48 in., T12, Recess Base)	12000	4000	3.0	0.50	2.00
Mercury Vapour	24000	4000	6.0	1.00	1.00
Mercury Vapour 125W *See Note	18000	4000	4.5	0.75	1.33
Metal Halide 175W	7500	4000	1.9	0.31	3.20
Metal Halide 250W	10000	4000	2.5	0.42	2.40
Metal Halide 400W	15000	4000	3.8	0.63	1.60
Metal Halide 1000W	10000	4000	2.5	0.42	2.40
High Pressure Sodium 70W	24000	4000	6.0	1.00	1.00
High Pressure Sodium 100W	24000	4000	6.0	1.00	1.00
Low Pressure Sodium	8000	4000	2.0	0.33	3.00

*** No Average life data was available for this lamp size in the references listed above. 75% of the quoted life for all Mercury Lamps was used.**

Nova Scotia Power Inc.
LED Streetlights
2014 CCA Schedule
Millions of dollars

Schedule 9

		1	2	3	4	5	6	7	8	9
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
		12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
Beginning UCC										
	8%	-	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320
		-	**-**	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**
Additions										
	8%		16,924,872	17,322,621	-	-	-	-	-	-
		-	**16,924,872**	**17,322,621**	**-**	**-**	**-**	**-**	**-**	**-**
CCA										
	8%	-	676,995	1,992,735	2,526,221	2,324,123	2,138,193	1,967,138	1,809,767	1,664,986
		-	**676,995**	**1,992,735**	**2,526,221**	**2,324,123**	**2,138,193**	**1,967,138**	**1,809,767**	**1,664,986**
Ending UCC										
	8%	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320	19,147,335
		-	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**	**19,147,335**
	Tax Rate:	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	Tax Savings from CCA :	-	209,868	617,748	783,129	720,478	662,840	609,813	561,028	516,146

Nova Scotia Power Inc.
LED Streetlights
2014 CCA Schedule
Millions of dollars

Schedule 9

	10	11	12	13	14	15	16	17	18	19	20
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025	12/31/2026	12/31/2027	12/31/2028	12/31/2029	12/31/2030	1/1/2031
Beginning UCC											
	19,147,335	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381
	19,147,335	**17,615,548**	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**
Additions											
	-	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
CCA											
	1,531,787	1,409,244	1,296,504	1,192,784	1,097,361	1,009,572	928,807	854,502	786,142	723,251	665,390
	1,531,787	**1,409,244**	**1,296,504**	**1,192,784**	**1,097,361**	**1,009,572**	**928,807**	**854,502**	**786,142**	**723,251**	**665,390**
Ending UCC											
	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381	7,651,991
	17,615,548	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**	**7,651,991**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	474,854	436,866	401,916	369,763	340,182	312,967	287,930	264,896	243,704	224,208	206,271

Nova Scotia Power Inc.
LED Streetlights
2014 CCA Schedule
Millions of dollars

Schedule 9

	21	22	23	24	25	26	27	
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	
	1/2/2031	1/3/2031	1/4/2031	1/5/2031	1/6/2031	1/7/2031	1/8/2031	**Total**
Beginning UCC								
	7,651,991	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	**357,611,954**
	7,651,991	**7,039,831**	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**357,611,954**
Additions								
	-	-	-	-	-	-	-	
	-	**-**	**-**	**-**	**-**	**-**	**-**	**34,247,493**
CCA								
	612,159	563,187	518,132	476,681	438,547	403,463	371,186	**29,978,856**
	612,159	**563,187**	**518,132**	**476,681**	**438,547**	**403,463**	**371,186**	**29,978,856**
Ending UCC								
	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	4,268,637	**361,880,591**
	7,039,831	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**4,268,637**	**361,880,591**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	**8**
	189,769	174,588	160,621	147,771	135,949	125,073	115,068	**9,293,445**

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent :														
Incandescent < 300 Watts - Note 1	001	97	$15.32	5.31	$1.96	$22.58	$7,317	$20.62	9.5%	27	$637	0.291	7.857	
Incandescent > 300 Watts - Note 1	002	154	24.32	5.31	2.08	$31.71	761	$29.22	8.5%	2	60	0.462	0.924	
Incandescent < 300 Watts - Note 1	003	97	15.32	0.00	0.00	$15.32	1,287	$14.43	6.2%	7	75	0.291	2.037	
							9,365			36	772			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43	6.80	5.31	3.33	$15.43	34,939	$13.86	11.3%	189	3,560	0.129	24.335	
Mercury Vapour 125 Watts	101	52	8.20	7.08	3.12	$18.40	1,717,149	$16.43	12.0%	7,778	184,016	0.156	1,213.339	
Mercury Vapour 175 Watts	102	69	10.88	5.31	3.09	$19.28	430,178	$17.51	10.1%	1,859	39,399	0.207	384.884	
Mercury Vapour 250 Watts	103	97	15.32	5.31	3.84	$24.47	210,289	$22.37	9.4%	716	18,041	0.291	208.423	
Mercury Vapour 400 Watts	104	154	24.32	5.31	3.92	$33.55	280,191	$30.93	8.5%	696	21,922	0.462	321.523	
Mercury Vapour 700 Watts	105	260	41.07	5.31	5.15	$51.53	6,802	$47.84	7.7%	11	487	0.780	8.580	
Mercury Vapour 1000 Watts	106	363	57.34	5.31	6.23	$68.87	71,078	$64.17	7.3%	86	4,860	1.089	93.654	
Mercury Vapour 250 Watt Cont. Oper.	107	212	26.00	10.61	3.84	$40.45	1,456	$36.67	10.3%	3	136	0.291	0.873	0.873
Mercury Vapour 125 Watts	201	52	8.20	7.08	0.00	$15.28	1,283	$13.40	14.0%	7	157	0.156	1.092	
Mercury Vapour 175 Watts	202	69	10.88	5.31	0.00	$16.19	4,079	$14.52	11.5%	21	421	0.207	4.347	
Mercury Vapour 250 Watts	203	97	15.32	5.31	0.00	$20.63	8,663	$18.68	10.4%	35	819	0.291	10.185	
Mercury Vapour 400 Watts	204	154	24.32	5.31	0.00	$29.63	3,200	$27.16	9.1%	9	267	0.462	4.158	
Mercury Vapour 700 Watts	205	260	41.07	5.31	0.00	$46.38	0	$42.93	8.0%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363	57.34	5.31	0.00	$62.65	16,539	$58.26	7.5%	22	1,159	1.089	23.958	
Mercury Vapour 125 Watts	301	52	8.20	0.00	0.00	$8.20	1,082	$7.74	5.9%	11	61	0.156	1.716	
Mercury Vapour 175 Watts	302	69	10.88	0.00	0.00	$10.88	20,498	$10.27	5.9%	157	1,149	0.207	32.499	
Mercury Vapour 250 Watts	303	97	15.32	0.00	0.00	$15.32	9,927	$14.43	6.2%	54	577	0.291	15.714	
Mercury Vapour 400 Watts	304	154	24.32	0.00	0.00	$24.32	4,378	$22.91	6.2%	15	254	0.462	6.930	
Mercury Vapour 700 Watts	305	260	41.07	0.00	0.00	$41.07	493	$38.68	6.2%	1	29	0.780	0.780	
Mercury Vapour 1000 Watts	306	363	57.34	0.00	0.00	$57.34	4,817	$54.01	6.2%	7	280	1.089	7.623	
							2,827,040			11,677	277,594			

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30	4.75	10.61	2.53	$17.89	192,575	$15.42	16.0%	897	26,551	0.091	81.627	
Fluorescent 2x48" 220 Watts	111	85	13.43	10.61	2.79	$26.83	36,710	$23.86	12.5%	114	4,070	0.254	28.956	
Fluorescent 2x72" 300 Watts	112	116	18.34	10.61	3.28	$32.23	25,913	$28.92	11.4%	67	2,661	0.348	23.316	
Fluorescent 4x72" 600 Watts	113	222	35.05	10.61	4.47	$50.13	9,024	$45.80	9.5%	15	780	0.665	9.975	
Fluorescent 1x96" 110 Watts	114	47	7.41	10.61	3.08	$21.11	1,266	$18.47	14.3%	5	158	0.141	0.705	
Fluorescent 1x72" 150 Watts	115	60	9.48	10.61	2.68	$22.77	273	$20.04	13.7%	1	33	0.180	0.180	
Fluorescent 4x48" 440 Watts	116	166	26.24	10.61	3.38	$40.24	966	$36.46	10.4%	2	91	0.499	0.998	
							266,727			1,101	34,344			
Fluorescent 4x72" 600 Watts	213	222	35.05	10.61	0.00	$45.66	0	$41.52	10.0%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47	7.41	10.61	0.00	$18.02	5,623	$15.48	16.4%	26	793	0.141	3.666	
Fluorescent 1x72" 150 Watts	215	60	9.48	10.61	0.00	$20.09	723	$17.42	15.3%	3	96	0.180	0.540	
Fluorescent 4x48" 440 Watts	216	166	26.24	10.61	0.00	$36.85	*0*	$33.19	11.0%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49	7.72	10.61	0.00	$18.33	220	$15.78	16.2%	1	31	0.146	0.146	
Fluorescent 2x48" 220 Watts	218	85	13.43	10.61	0.00	$24.04	0	$21.14	13.7%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47	7.41	0.00	0.00	$7.41	178	$6.99	6.0%	2	10	0.140	0.280	
							6,744			32	930			
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486	59.60	0.00	0.00	$59.60	715	$56.15	6.1%	1	41	0.665	0.665	0.665
Fluorescent 2x24" 70 Watts	118	66	8.08	0.00	0.00	$8.08	1,648	$7.62	6.0%	17	94	0.091	1.547	1.547
Fluorescent 4x48" 440 Watts	119	364	44.65	0.00	0.00	$44.65	12,323	$42.05	6.2%	23	718	0.499	11.477	11.477
Fluorescent 2x96"	120	254	31.16	0.00	0.00	$31.16	11,218	$29.34	6.2%	30	655	0.348	10.440	10.440
Fluorescent 4x96"	150	613	75.18	0.00	0.00	$75.18	18,945	$70.82	6.2%	21	1,099	0.840	17.640	17.640
							44,850			92	2,607			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30	4.75	0.00	0.00	$4.75	114	$4.46	6.5%	2	7	0.091	0.182	
Fluorescent 4x48" 440 Watts	311	166	26.24	0.00	0.00	$26.24	1,574	$24.70	6.2%	5	92	0.499	2.495	
Fluorescent 2x72" 300 Watts	312	116	18.34	0.00	0.00	$18.34	220	$17.26	6.3%	1	13	0.348	0.348	
Fluorescent 4x72" 600 Watts	313	222	35.05	0.00	0.00	$35.05	0	$33.03	6.1%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47	7.41	0.00	0.00	$7.41	2,223	$6.99	6.0%	25	126	0.142	3.550	
Fluorescent 1x72" 150 Watts	315	60	9.48	0.00	0.00	$9.48	0	$8.93	6.2%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280	44.24	0.00	0.00	$44.24	40,347	$41.66	6.2%	76	2,353	0.841	63.916	
							44,478			109	2,591			

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60	9.48	15.92	6.02	$31.42	15,019	$27.39	14.7%	40	1,929	0.180	7.170	
Low Pressure Sodium 180 Watts	131	80	12.64	15.92	8.72	$37.28	163,072	$32.86	13.4%	365	19,328	0.240	87.481	
Low Pressure Sodium 90 Watts	132	45	7.10	15.92	6.02	$29.04	0	$25.16	15.5%	0	0	0.135	0.000	
Low Pressure Sodium 180 Watts E&M	231	80	12.64	15.92	0.00	$28.56	13,366	$24.64	15.9%	39	1,836	0.240	9.360	
Low Pressure Sodium 180 Watts E/O	331	80	12.64	0.00	0.00	$12.64	5,612	$11.90	6.2%	37	329	0.240	8.880	
							197,069			480	23,422			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100	15.80	5.31	3.35	$24.45	952,006	$22.36	9.4%	3,244	81,518	0.300	973.336	
High Pressure Sodium 400 Watts	122	150	23.69	5.31	3.47	$32.46	851,958	$29.91	8.5%	2,187	66,985	0.450	984.158	
High Pressure Sodium 70 Watts	123	32	5.04	5.31	3.15	$13.49	4,377,829	$12.05	11.9%	27,040	467,093	0.096	2,595.850	
High Pressure Sodium 100 Watts	124	45	7.10	5.31	3.17	$15.58	6,096,299	$14.02	11.1%	32,612	611,031	0.135	4,402.640	
High Pressure Sodium 150 Watts	125	65	10.27	5.31	3.35	$18.93	894,775	$17.16	10.3%	3,939	83,868	0.195	768.083	
HP Sodium 100 Watts - Cont. Oper.	126	99	12.12	10.61	3.17	$25.90	4,663	$23.00	12.6%	15	522	0.135	2.025	2.025
High Pressure Sodium 250 Watts	221	100	15.80	5.31	0.00	$21.11	43,310	$19.13	10.4%	171	4,065	0.300	51.300	
High Pressure Sodium 70 Watts	222	32	5.04	5.31	0.00	$10.35	32,032	$9.01	14.9%	258	4,152	0.096	24.768	
High Pressure Sodium 100 Watts	223	45	7.10	5.31	0.00	$12.41	20,098	$10.95	13.3%	135	2,367	0.135	18.225	
High Pressure Sodium 150 Watts	224	65	10.27	5.31	0.00	$15.58	42,991	$13.92	11.9%	230	4,585	0.195	44.850	
High Pressure Sodium 250 Watts	321	100	15.80	0.00	0.00	$15.80	182,774	$14.88	6.2%	964	10,643	0.300	289.200	
High Pressure Sodium 70 Watts	322	32	5.04	0.00	0.00	$5.04	361,549	$4.76	5.9%	5,978	20,086	0.096	573.888	
High Pressure Sodium 100 Watts	323	45	7.10	0.00	0.00	$7.10	202,520	$6.70	6.0%	2,377	11,410	0.135	320.895	
High Pressure Sodium 150 Watts	324	65	10.27	0.00	0.00	$10.27	15,405	$9.67	6.2%	125	900	0.195	24.375	
High Pressure Sodium 400 Watts	326	150	23.69	0.00	0.00	$23.69	25,301	$22.32	6.1%	89	1,463	0.450	40.050	
High Pressure Sodium 500 Watts	327	183	28.92	0.00	0.00	$28.92	1,041	$27.23	6.2%	3	61	0.550	1.650	
High Pressure Sodium 1000 Watts	328	363	57.35	0.00	0.00	$57.35	9,635	$54.01	6.2%	14	561	1.090	15.260	
High Pressure Sodium 1500 Watts	329	500	78.98	0.00	0.00	$78.98	948	$74.39	6.2%	1	55	1.090	1.090	
							14,115,135			79,383	1,371,310			

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150	23.69	8.49	3.96	$36.14	395,360	$32.92	9.8%	912	35,271	0.450	410.235	
Metallic Arc 1000 Watts	141	360	56.87	12.74	5.79	$75.39	887,524	$69.25	8.9%	981	72,318	1.080	1,059.480	
Metallic Arc 250 Watts	142	100	15.80	12.74	3.90	$32.43	28,864	$28.82	12.6%	74	3,220	0.300	22.248	
Metallic Arc 150 Watts	143	67	10.57	12.74	3.90	$27.20	1,306	$23.91	13.8%	4	158	0.200	*0.800*	
Metallic Arc 100 Watts	144	50	7.90	12.74	3.90	$24.53	1,283	$21.38	14.8%	4	165	0.150	0.654	
Metallic Arc 1000 Watts	341	360	56.87	0	0	$56.87	15,014	$53.56	6.2%	22	874	1.080	23.760	
Metallic Arc 400 Watts	342	150	23.69	0	0	$23.69	45,201	$22.32	6.1%	159	2,614	0.450	71.550	
Metallic Arc 250 Watts	343	100	15.80	0	0	$15.80	15,926	$14.88	6.2%	84	927	0.300	25.200	
Metallic Arc 175 Watts	344	75	11.85	0	0	$11.85	15,926	$11.16	6.2%	112	927	0.225	25.200	
Metallic Arc 150 Watts	345	67	10.57	0	0	$10.57	2,537	$9.97	6.0%	20	144	0.200	4.000	
Metallic Arc 100 Watts	346	50	7.90	0	0	$7.90	0	$7.44	6.2%	0	0	0.150	0.000	
							1,408,941			2,372	116,618			
Light Emitting Diode - Traffic Lights														
Light Emitting Diode 4.6 Watts	530	3	0.39	0	0	$0.39	0	$0.36	8.3%		0		0.000	
Light Emitting Diode 7.5 Watts	531	5	0.65	0	0	$0.65	0	$0.61	6.6%		0		0.000	
							0							
Light Emitting Diode (Energy Only)														
Lighting Emitting Diode 44 Watts	532	15	2.37	0	0	$2.37	49,258	$2.23	6.3%	1,732	2,910	0.440	762.080	
Lighting Emitting Diode 66 Watts	533	22	3.48	0	0	$3.48	5,763	$3.27	6.4%	138	348	0.660	91.080	
Lighting Emitting Diode 88 Watts	534	29	4.58	0	0	$4.58	28,194	$4.31	6.3%	513	1,662	0.880	451.440	
Lighting Emitting Diode 92 Watts	535	31	4.90	0	0	$4.90	0	$4.61	6.3%	0	0	0.920	0.000	
Lighting Emitting Diode 105 Watts	536	35	5.53	0	0	$5.53	0	$5.21	6.1%	0	0	0.105	0.000	
Lighting Emitting Diode 170 Watts	537	57	9.00	0	0	$9.00	0	$8.48	6.1%	0	0	0.170	0.000	
Lighting Emitting Diode 110 Watts	539	37	5.84	0	0	$5.84	182,839	$5.50	6.2%	2,609	10,645	0.110	286.990	
Lighting Emitting Diode 65 Watts	540	22	3.48	0	0	$3.48	19,377	$3.27	6.4%	464	1,169	0.650	301.600	
Lighting Emitting Diode 55 Watts	541	18	2.84	0	0	$2.84	25,083	$2.68	6.0%	736	1,413	0.550	404.800	
Lighting Emitting Diode 83 Watts	542	28	4.42	0	0	$4.42	55,109	$4.17	6.0%	1,039	3,117	0.830	862.370	
Lighting Emitting Diode 48 Watts	543	16	2.53	0	0	$2.53	2,186	$2.38	6.3%	72	130	0.830	59.760	
Lighting Emitting Diode 72 Watts	544	24	3.79	0	0	$3.79	14,008	$3.57	6.2%	308	813	0.830	255.640	
							381,816			7,611				

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Light Emitting Diode (Energy & Capital														
LED A1	615	15	2.37	0	10.00	$12.37	1,790,030	$12.05	2.7%	12,056	47,243	0.830	10,006.569	
LED A2	616	18	2.84	0	10.00	$12.84	531,038	$12.50	2.8%	3,446	14,329	0.830	2,859.951	
LED A4	617	25	3.95	0	10.00	$13.95	137,843	$13.54	3.1%	823	4,115	0.830	683.308	
LED A3	618	29	4.58	0	10.00	$14.58	3,086	$14.13	3.2%	18	97	0.830	14.638	
LED B1	619	22	3.48	0	10.00	$13.48	2,337,349	$13.09	3.0%	14,446	68,744	0.830	11,990.483	
LED C1	620	29	4.58	0	10.00	$14.58	388,934	$14.13	3.2%	2,223	12,176	0.830	1,844.711	
LED C3	621	37	5.84	0	10.00	$15.84	319,419	$15.32	3.4%	1,680	10,616	0.830	1,394.512	
LED C2	622	58	9.16	0	10.00	$19.16	338,300	$18.45	3.9%	1,471	12,650	0.830	1,221.061	
							5,845,998			36,163				
TOTALS							**$25,148,164**			**139,056**			**49,016.734**	**44.667**
										102,893				

Non LED	**95,282**
LED	**43,774**
Total	**139,056**

Non LED	
Energy Only	83,885
Maintenance	957
Capital	10,440
Total	95,282
LED	
Energy Only	7,611
Capital	36,163
Total	43,774
Grand Total	139,056

SCHEDULE 10

2014 STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)

Count = 93

Note 1 - Red highligted P&E charges relate to calculated rounding differences using Misc. Small Loads Tariff.
Note 2 - Incandescent rates were set at 250W and 400W Mercury Vapour

Miscellaneous Small Loads Rate		
Demand Charge	$/kW	**11.534**
Block 1 Energy		
Base cost of fuel	¢/kWh	4.876
Non-fuel	¢/kWh	8.315
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 1 (first 200kWh *	¢/kWh	**13.191**
Block 2 Energy		
Base cost of fuel	¢/kWh	4.876
Non-fuel	¢/kWh	3.882
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 2	¢/kWh	**8.758**

Calculation of Power & Energy Rate :
Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

Photocell Operation (4000 burning hours per year)			
Demand Charge $/kW (annual)		12.246	$146.95
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.14005	336.12
2nd Block : All additional (annual)	1,600	0.09298	148.77
			$631.84
Rate per kW.h	4,000		**$0.1579590**
Continuous Burning (8760 burning hours per year)			
Demand Charge $/kW (annual)		12.246	$146.95
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.14005	336.12
2nd Block : All additional (annual)	6,360	0.09298	591.35
			$1,074.42
Rate per kW.h	8,760		**$0.1226508**

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount ~~requested~~ required by NSPI within ten (10) minutes of ~~such request by the Company~~NSPI initiating a telephone call to send notice to the customer's dedicated telephone number requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's dedicated telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a ~~request~~requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice~~request~~) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI~~interruption call was delivered by telephone call~~.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings

shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

LOAD RETENTION TARIFF PRICING MECHANISM

AVAILABILITY:

1. This Load Retention Pricing Mechanism (Pricing Mechanism) is available to, Bowater Mersey Paper Company Ltd (Bowater) for energy other than presently served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this Pricing Mechanism must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF tariff customers, and in advance of Interruptible Rider customers.

4. This Pricing Mechanism cannot be taken in conjunction with other Tariffs, except for the ability of Bowater to take energy under the Mersey Agreement.

RATE MECHANISM:

The intent of this rate is to create a mechanism whereby customers on the rate pay the variable incremental costs of service, plus a significant positive contribution to fixed costs, such that other customers are better off by retaining the customers rather than having the customers depart the system and make no contribution to fixed cost recovery.

LOAD RETENTION TARIFF PRICING MECHANISM

CHARGES:

Energy Charge

The Energy Charge shall be as follows:

Year (January 1 to December 31)	Variable Incremental Rate (cents per kWh)	Contribution to fixed costs (cents per KWh)	Energy charge (cents per kWh)
2012	5.624	0.4	6.024
2013	6.177	0.4	6.577
2014	6.386	0.4	6.786

RE-OPENER CLAUSE

The UARB reserves the right to adjust the above rates on a prospective basis if actual costs significantly vary from Load Retention Rate assumptions. Following any adjustment, the customer would be provided the opportunity to determine whether to remain on the rate.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) is applicable to the Tariff for the 2012 rate year only. For 2012, the rate applicable to the Extra Large Industrial Two Part Real Time Pricing Tariff (ELI 2P-RTP) approved by the UARB pursuant to the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge in 2012.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the ELI 2P-RTP Tariff for the 2012 rate year on account of fuel and purchased power costs incurred in 2010 and 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2012 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2012.

The ELI 2P-RTP portion of the FAM BA (in cents per kilowatt hour) for the 2013 rate year on account of fuel and purchased power costs incurred in 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2013 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2013.

No other FAM charges shall be applicable to this Tariff.

SPECIAL CONDITIONS:

Major Scheduled Maintenance Periods

LOAD RETENTION TARIFF PRICING MECHANISM

The customer will annually provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

Day Ahead Forecast

The customer shall supply NSPI, by 0800 hours each day, a 24 hour forecast for the following day of the customer's hourly requirements in MW.

Minimum Load Requirement:

The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a regular demand of 25 000 kVA.

Supply Interruption:

This Pricing Mechanism is interruptible for supply reasons. The customer will reduce its subscribed interruptible system load by the amount ~~requested~~required by NSPI within ten (10) minutes of~~ such request by the Company~~ NSPI initiating a telephone call to send notice to the customer requiring such reduction. ~~. ~~Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes. The customer must maintain a telephone number and telephone system in working order at all times and must have a designated staff person to answer the telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Supply Interruption calls will be made to all customers taking energy pursuant to this Pricing Mechanism on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a ~~request~~requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the cost of the applicable billing for energy taken under this tariff effective at that time for the consumption used in that ~~billing period~~month.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

LOAD RETENTION TARIFF PRICING MECHANISM

Performance Penalty = ($15/kVA x A) + (($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice ~~request~~) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI ~~interruption call was delivered by telephone call~~.

"B" is the customer's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A"

The total penalty will not exceed two times the cost of the appropriate billing effective at that time for the consumption used in that ~~billing period~~month.

Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to the company so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to Interruptible service in the future, the customer may convert to interruptible service following two (2) years service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GR&LF) Rate;
2. Load Retention Tariff Pricing Mechanism;
3. Interruptible Rider to the Large Industrial Rate.

Maintain System Integrity

The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

LOAD RETENTION TARIFF PRICING MECHANISM

Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic Voltage and current levels, Voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

Security for Payment of Account

The customer shall make weekly payments on account of its estimated monthly billings from NSPI. NSPI shall provide the customer with a reasonable estimated weekly billing for each week (Monday through Sunday, prorated for the first and last week, or such other weekly period as the customer and NSPI may agree) during the term. Prior to close of business each Thursday immediately following a billing week (or as otherwise subsequently agreed), the customer shall make a payment by wire transfer to NSPI's account equal to that prior week's estimated amount as provided by NSPI. If NSPI does not provide the applicable weekly estimate to the customer in advance of the Thursday payment requirement, the customer shall make payment in accordance with the immediately prior estimate. At the end of each month the customer shall, as applicable, make an additional payment or receive a credit towards its next payment in order to balance its account to actual prior month's usage.

Separate Service Agreement

The Company reserves the right to have a separate service agreement if, in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

LOAD RETENTION TARIFF PRICING MECHANISM

Metering Costs

Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

Open Access Transmission Tariff Update

May 8, 2012

TABLE OF CONTENTS

1 INTRODUCTION

This Application by Nova Scotia Power Inc. seeks approval from the Nova Scotia Utility and Review Board for:

1. an update to the prices for the services offered under NS Power's Open Access Transmission Tariff (OATT), and

2. a ratemaking methodology for the determination and recovery of the embedded cost obligations of the Municipal Electric Utilities (MEU) if they use the OATT to take delivery of energy from third party suppliers.

The OATT includes terms, conditions and rates for Transmission Services and Ancillary Services; service and operating agreements under which service will be provided; and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power. The OATT, as approved by the Board in 2005, is available at: http://oasis.nspower.ca/en/home/oasis/default.aspx

There have been no changes to this tariff since it was originally approved in 2005. NS Power does not propose any changes to the approved pricing methodology or to the terms, conditions and services of the tariff. The rates proposed have been updated to reflect the changes in revenue requirement, as driven by changes in costs of employed resources and changes in system usage since 2005.

NS Power proposes an Embedded Cost Recovery Mechanism to mitigate the risk of transferring cost obligations, currently recovered from the MEU through their Bundled Municipal tariff service, to other customers if the MEU exercise their option to take energy supply from third parties. The proposed approach aligns with those used in other jurisdictions and fairly assigns recovery of cost obligations to the customers who create them.

2 UPDATE TO CHARGES UNDER THE OPEN ACCESS TRANSMISSION TARIFF

2.1 Introduction

As approved by the Board in 2005[1], the OATT defines the terms, conditions and prices under which an Eligible Customer can gain access to the Transmission System. NS Power does not propose any changes to the approved pricing methodology or to the terms, conditions and services of the tariff. The rates proposed have been updated to reflect the changes in revenue requirement, as driven by changes in generation and transmission asset mix and costs, and changes in system usage since 2005.

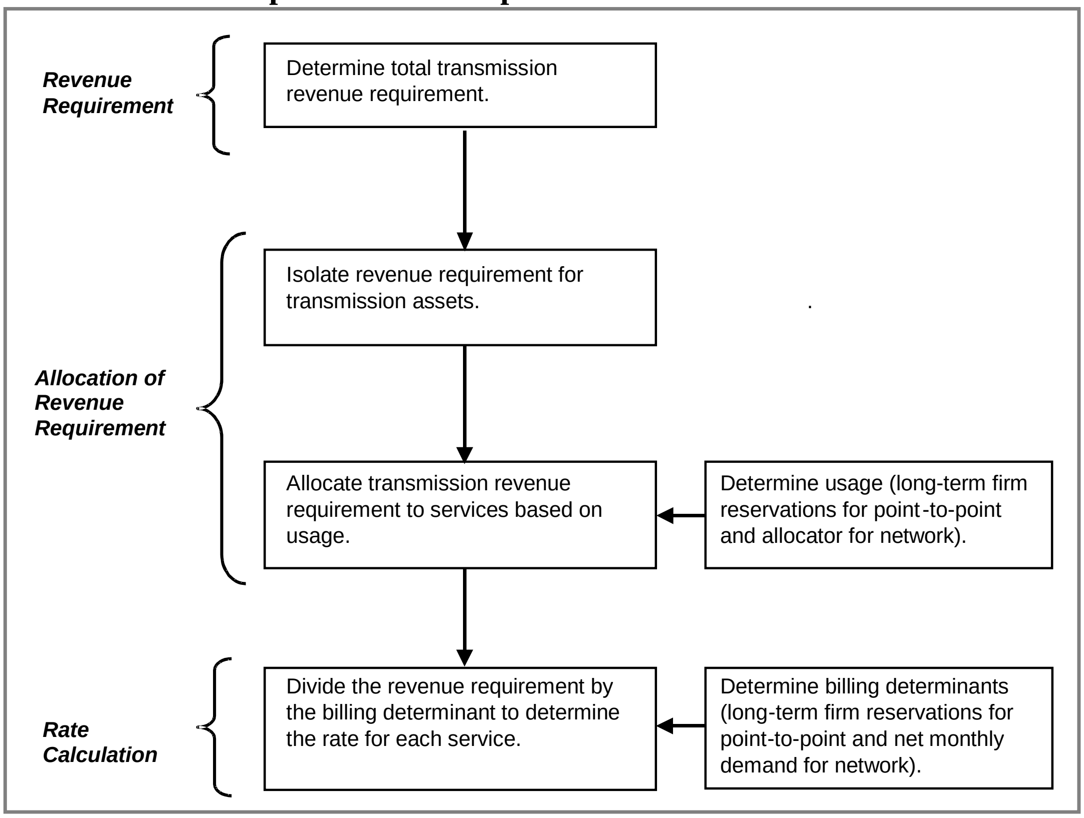
The information that follows describes the Board-approved methodology for the development of the revenue requirements and their allocation to the transmission services of the OATT. It also describes the calculations for the ancillary services, which includes scheduling, system control, and dispatch. All transmission charges shown are updated for costs and load determinants forecasted for 2013 and 2014. The ancillary charges are based on 2011 actual data.

2.2 Transmission Services

The process of updating the transmission tariff is illustrated in Figure 2-1.

[1] NSPI Application for Approval of an Open Access Transmission Tariff, UARB Order, NSUARB-NSPI-P-880, May 31, 2005.

Figure 2-1
Overview of the Steps taken in the Update of Transmission Rates



2.2.1 Transmission Revenue Requirement

To calculate the transmission tariff, the appropriate revenue requirement that must be recovered from the sale of Transmission Services is determined. The total revenue requirement related to NS Power's Transmission System is $108.5 million in 2013 and $115.3 million in 2014, as outlined in Figure 2-2.

Figure 2-2

Transmission System Revenue Requirement		
Revenue Requirement Component	**2013 ($M)**	**2014 ($M)**
Depreciation	24.1	25.6
O&M including overhead costs	26.6	26.8
Interest, taxes and return on equity	54.6	59.5
FCR Deferral	3.2	3.3
Total	**108.5**	**115.3**

The revenue requirement shown in Figure 2-2 includes the costs of all transmission lines at voltages of 69 kV or higher and the terminal stations associated with those transmission lines. It also includes the revenue requirement associated with the generation step up transformers for NS Power's generators.

2.2.2 Allocation of Revenue Requirement

The purpose of revenue requirement allocation is to allocate the appropriate revenue requirement (that is, the costs associated with transmission) to the appropriate services. The following steps are required to do this in a manner that is both efficient and equitable:

- definition of the Transmission Services to be provided
- definition of the basic functions of the Transmission System
- allocation of transmission revenue requirements to the different functional uses of the system
- determination of system usage by service
- allocation of the functional costs to the Transmission Services

2.2.2.1 Services Defined in the Tariff

There are two basic Transmission Services available under the OATT: Point-to-Point service and Network Integration Service. In addition, the Ancillary Service of scheduling, system control, and dispatch are an obligatory service that can only be provided by the Transmission Provider and must be taken by the Transmission Customer. The rate design for Point-to-Point Service and Network Integration Service, and the Scheduling, Control and Dispatch Service is considered within this section, while the rates for the other Ancillary Services are detailed in Section 2.3.

Point-to-Point Service refers to the reservation of capacity (for a specified period of time and a specified number of MWs) to allow the transmission of energy from a Point of Receipt to a Point of Delivery. An example of this is a one-month reservation of 100 MW from a generator inside Nova Scotia (the Point of Receipt) to the New Brunswick interconnection (the Point of Delivery). This service is available on either a firm or a non-firm basis.

Network Service is firm Transmission Service for the delivery of both capacity and energy to the high side of the substation transformer of the Transmission Customer. It is usually used for supply of load within the system.

Scheduling, System Control, and Dispatch Service is the process through which the system operator ensures that scheduled transactions are executed. It is required to schedule the movement of power into, out of, and within Nova Scotia. Only the NS Power System Operator can provide this service.

2.2.2.2 Transmission Functions

The services defined in the OATT and described in the previous section use different parts of the Transmission System.

To ensure appropriate cost allocation, it is necessary to break down the revenue requirement into component pieces. Only after such a breakdown is completed can costs be allocated to specific services.

This section identifies which assets are used to provide which services. For the purposes of the NS Power OATT, assets have been grouped into three main functional groups as follows:

- Generation Related Transmission Assets

- Bulk Network Assets, which can be further subdivided into:
  - Interconnections
  - In-province Network
- Radial-to-Load Assets

In order to perform this allocation of transmission assets and their associated costs, it is necessary that the division point between functional groups be defined. The division points and the types of assets allocated to the different functions are explained below.

Direct Assignment Facilities are generation-related transmission assets (GRTA) that serve the function of connecting generation units to the shared Transmission System. They consist of generator step up transformers (GSU), a portion of substation assets, and transmission lines whose primary purpose is to connect a generator to the Transmission System. These assets and the associated revenue requirements are to be recovered directly from the generation owners and not accounted for in the rate for the transmission tariff.

Bulk Network Assets make up a portion of the Transmission System that is highly interconnected and that serves multiple functions. The bulk network has two components: Interconnections and In-province Assets. Interconnections are transmission lines that interconnect with the New Brunswick electrical system at the provincial border. The In-province Assets consist of all transmission lines that operate as part of the integrated system within Nova Scotia.

Radial-to-Load Assets are those parts of the Transmission System that are not a part of the integrated network and are used only to serve in-province loads. However, because the impact of including radial-to-load as part of the bulk power network is not large, and because the status of these assets may change each time new generation is connected to these lines, the approved ratemaking methodology includes these assets with the bulk power network assets.

2.2.2.3 Functional Allocation of Costs

The allocation of the Transmission Services revenue requirement of $108.5 million in 2013 and $115.3 million in 2014 to the functional uses of the system is summarized in Figure 2-3. Details of this allocation are found in Attachment 2.

Figure 2-3

Functional Allocation of Revenue Requirements		
Functional Use	**Revenue Requirement Share ($M)**	
	2013	**2014**
Generator Related Transmission Assets (GRTA)	6.2	6.4
Bulk Network In Province	94.2	100.5
Energy Control Centre	8.1	8.4
TOTAL	**108.5**	**115.3**

The Transmission OATT revenue requirement, which does not include the GRTA category, is $94.2 million in 2013 and $100.5 million in 2014. The costs for the Energy Control Centre are $8.1 million in 2013 and $8.4 million in 2014 and are recovered through Schedule 1 Scheduling, System Control and Dispatch Ancillary Service found in Attachment 1.

2.2.2.4 Determination of System Usage

The Transmission revenue requirement is allocated between Point-to-Point and Network Integration Services on the basis of the monthly coincident peak system load. Absent any long-term firm Point-to-Point reservations, the usage under this service is determined on the basis of NS Power's exports over the last five years, averaged across all hours. The average used in this Application is 16 MW.

The resulting system usage is shown in Figure 2-4.

Figure 2-4

Transmission System Usage			
Usage	**Quantity (MW)**		**Allocation Factors (%)**
	2013	**2014**	
Average export usage over 5 years	16	16	0.96
Forecast average of Network Loads at the time of the 12 monthly system peaks in 2013 and 2014	1664	1662	99.04
Total	**1680**	**1678**	**100.00**

2.2.2.5 Allocation of Revenue Requirements to Services

The last step in the cost allocation analysis is to allocate total transmission costs to the services that will be offered under the tariff. As noted above, these are Point-to-Point Service, Network Service and the Scheduling, System Control and Dispatch Service.

The Transmission revenue requirement for Point-to-Point and Network Services has been determined in Section 2.2.2.3 as $94.2 million/year in 2013 and $100.5 million in 2014. Applying 0.96 percent share of usage for Point-to-Point reservations and 99.04 percent for Network Service, the allocation of costs to these services is shown in Figure 2-5.

Figure 2-5

Transmission Services Revenue Requirements			
Service	**Share %**	**Revenue Requirement ($M)**	
		2013	**2014**
Point-to-Point	0.96	0.9	1.0
Network	99.04	93.3	99.5
Total	**100.00**	**94.2**	**100.5**

The revenue requirement for each service can also be expressed on a per-unit of usage basis as shown in Figure 2-6. The $/MW/year figures represent the per-unit cost of providing each of the services based on the application of the transmission pricing principles.

Figure 2-6

Per Unit Transmission Services Revenue Requirements			
Service	**Revenue Requirement ($M)**	**Usage (MW)**	**Per Unit Revenue Requirement ($/MW/year)**
2013			
Point-to-Point	0.9	16	56,046.05
Network	93.2	1664	56,046.05
2013 Total	**94.2**	**1680**	56,046.05
2014			
Point-to-Point	1.0	16	59,875.87
Network	99.5	1662	59,875.87
2014 Total	**100.5**	**1678**	59,875.87

2.2.3 Determination of Rates

The nominal rates for each service are determined by dividing their revenue requirements by the respective billing determinant. For Point-to-Point Transmission Service, the approved billing determinant is the transmission capacity reserved by the customer.

For Network Integration Transmission Service, the approved billing determinant is monthly non-coincident peak (NCP) demand. The NCP demand for all Eligible Customers (except NS Power) is available from existing metering. Given the lack of complete metering, NS Power uses a coincidence factor to derive NS Power's NCP demand from the known coincident peak demand. For the purpose of this Application, NS Power applied the coincidence factor of 85.0 percent as used in the 2005 submission.

Figure 2-7 illustrates the calculation of the nominal annual rate for each service.

Figure 2-7

Determination of Nominal Rates by Service			
Services	**Revenue Requirement ($M/year)**	**Billing Determinant (MW)**	**Nominal Rate ($/MW/year)**
2013			
Point to Point Services			
Transmission Service	0.9	16	56,046.05
Scheduling, Control & Dispatch	0.8	16	4,838.94
Network Services			
Transmission Service	93.3	1664	56,046.05
Scheduling, Control & Dispatch	8.1	1664	4,838.94
2014			
Point to Point Services			
Transmission Service	1.0	16	59,875.87
Scheduling, Control & Dispatch	0.1	16	4,997.38
Network Services			
Transmission Service	99.5	1662	59,875.87
Scheduling, Control & Dispatch	8.3	1662	4,997.38

For time differentiated Point-to-Point Service, NS Power is using Appalachian pricing. In Appalachian pricing the short term services are priced higher for an equivalent time period.

The Appalachian pricing approach defines various short term rates as a fraction of the yearly rate as follows:

- Yearly = nominal rate
- Monthly rate = Yearly rate / 12
- Weekly rate = Yearly rate / 52
- On-Peak Daily rate = Weekly rate / 5
- Off-Peak Daily rate = Yearly rate / 365
- On-Peak Hourly rate = On-Peak Daily rate / 16
- Off-Peak Hourly rate = Yearly rate / 8760

NS Power has proposed rates based on the previously-approved calculations shown above. This approach helps ensure adequate collection of revenues for services provided, while facilitating the use of the transmission capacity in the off-peak hours. Based on the overall revenue requirement defined, the application of the revenue requirement allocation analysis, and the design of the end use rates just described, the rates proposed by NS Power for approval by the Board are set out in Figure 2-8.

Figure 2-8

Summary of Transmission Service Rates			
Services	**Units**	**Transmission Service**	**Scheduling, System Control & Dispatch**
2013			
Point-to-Point			
Yearly	$/MW-yr	56,046.05	4,838.94
Monthly	$/MW-m	4,670.50	403.24
Weekly	$/MW-w	1,077.81	93.06
On-Peak Daily	$/MW-d	215.56	18.61
Off-Peak Daily	$/MW-d	153.55	13.26
On-Peak Hourly	$/MW-h	13.47	1.16
Off-Peak Hourly	$/MW-h	6.40	0.55
Network	$/MW-m	3,969.93	342.76
2014			
Point-to-Point			
Yearly	$/MW-yr	59,875.87	4,997.38
Monthly	$/MW-m	4,989.66	416.45
Weekly	$/MW-w	1,151.46	96.10
On-Peak Daily	$/MW-d	230.29	19.22
Off-Peak Daily	$/MW-d	164.04	13.69
On-Peak Hourly	$/MW-h	14.39	1.20
Off-Peak Hourly	$/MW-h	6.84	0.57
Network	$/MW-m	4,241.21	353.98

Additional details with respect to the derivation of these rates are provided in Attachment 2.

2.2.4 Power Factor Penalty in the Transmission Tariff

NS Power's OATT includes a power factor penalty that will be applied for any month in which a Transmission Customer has a power factor of less than 0.90. As approved by the Board, the penalty paid shall be based on Excess kVA, where Excess kVA shall be defined as:

- Excess kVA = Max. kVA – Max. kW / 0.9

where:

- Max. kVA = Maximum kVA demand during the month
- Max. kW = Maximum kW demand during the month

The charge per Excess kVA is the demand charge of the NS Power Large Industrial Rate in effect.

2.3 Ancillary Services Rates

Ancillary Services are the support services that are required to enable the Transmission System to transmit energy while maintaining reliable operation of the system in accordance with Good Utility Practice. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to maintain the integrity of the Transmission System and enable it to be operated reliably at design voltages and frequency.

This section discusses calculations of rates for all of the Ancillary Services that are provided by generators under the control of the System Operator at the Energy Control Centre. Scheduling, System Control, and Dispatch Service is an Ancillary Service supplied directly by the Transmission Provider and is discussed in Section 2.2.

The Ancillary Services provided by generators and discussed in this section can be grouped into two main categories:

- Capacity Based Services provided from generation capacity that must be committed to the provision of the service and cannot be used at the same time for other purposes

- Non-capacity Based Services that do not require the commitment of generator capacity for provision of the service

2.3.1 Capacity Based Ancillary Services

Capacity Based Services include the following:

- Regulation and Frequency Response from Generation Sources Service (Schedule 3 in Attachment 1), composed of:
    - Regulation
    - Load Following

- Operating Reserve – Spinning Reserve Service (Schedule 5 in Attachment 1)

- Operating Reserve – Supplemental Reserve Service (Schedule 6 Attachment 1), composed of:
    - Supplemental (10-minute)
    - Supplemental (30-minute)

The costs of supplying these services are calculated from the embedded costs of existing generating units.

The revenue requirement for Capacity Based Services (Schedule 3, 5 and 6 in Attachment 1) is determined by multiplying the per-unit embedded cost of capacity for each service by the amount of capacity required to deliver the service.

Once the revenue requirement is determined, it is allocated to services, and rates are set in a manner similar to that used for Transmission Services in Section 2.2.

2.3.1.1 Requirements of Capacity Based Ancillary Services

NS Power, as the Transmission Provider, has a responsibility to operate in accordance with North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) criteria. This includes the responsibility to determine the need for and to procure sufficient ancillary resources to reliably operate the electrical power network.

Additionally, the NS Power OATT obligates NS Power, as the Transmission Provider, to make all Ancillary Services available to all Transmission Customers. Therefore, NS Power must be able to procure adequate generation resources to do so.

Transmission Customers can purchase each of the Ancillary Services from the Transmission Provider (NS Power) whether they are taking Point-to-Point or Network Service. Therefore, the Ancillary Services are priced for both services. Transmission Customers can self-supply the Capacity Based Ancillary Services, or purchase them from either the Transmission Provider or a third party. The NS Power system requirements for Regulation and Frequency Response and Operating Reserves are outlined below.

2.3.1.2 Regulation and Frequency Response

Historical operating experience was used to determine the amount of capacity that is required to provide the Regulation and Frequency Response Ancillary Service. Nova Scotia load has two characteristics that dictate the requirements of this Ancillary Service:

10 minute-by-10 minute load fluctuations (Regulation) and the change in load from hour to hour (Load Following). For the rate updating purposes of this Application, NS Power used 10 minute time interval, as opposed to a 1 minute time interval as used in the 2005 Application, for regulation requirements. This is done to capture the variation in wind generation which has increased significantly since 2005 and which must be followed by other generators in Nova Scotia.

The 10 minute-by-10 minute fluctuations require 58 MW of generation capacity for the Nova Scotia system, and the hour-to-hour change in load requires 151 MW of generation capacity.

2.3.1.3 Operating Reserves

NPCC defines the requirement for Operating Reserves in the Maritimes Control Area. NS Power is obligated to provide its share of Operating Reserves as follows:

- Spinning Reserve 33 MW
- 10 Minute (non-spinning) Reserve 138 MW
- 30 Minute Reserve 50 MW

This means that at all times, NS Power must have: 33 MW of spare capacity available from units already on line, 138 MW of capacity (or load reduction) that can be made available within 10 minutes, and an additional 50 MW of capacity (or load reduction) that can be made available within 30 minutes.

2.3.1.4 Summary of Revenue Requirements for Capacity Based Ancillary Services

The total revenue requirement for each service is the product of the quantity required multiplied by the cost per unit of service supplied as shown in Figure 2-9.

Figure 2-9

Revenue Requirement of Capacity Based Ancillary Services			
Services 2013 and 2014	**Revenue Requirement ($/kW/year)**	**Services Required (MW)**	**Revenue Requirement ($1000/year)**
Regulation	87.49	58	5,092.18
Load Following	120.77	151	18,224.83
Operating Reserve – Spinning	118.42	33	3,908.02
Operating Reserve – Supplemental (10 minute)	56.41	138	7,784.77
Operating Reserve – Supplemental (30 minute)	131.95	50	6,597.75

Additional detail with respect to the derivation of these revenue requirements is provided in Attachment 3.

2.3.1.5 Capacity Based Ancillary Service Rates

The annual cost of providing each service as a function of the usage is determined by dividing the total cost of providing the service by the usage of the respective service. For monthly Point-to-Point and Network Services, the annual cost of providing each service on a $/kW basis is divided by twelve to determine the monthly rate. Point-to-Point customers purchasing the Ancillary Services on a yearly or monthly basis, as well as customers taking Network Service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the OATT. The rate for weekly Point-to-Point Services is 1/52nd of the annual rate and the daily rate is 1/7th of the weekly rate. Hourly service is not available for the Capacity Based Ancillary Services due to the additional administrative burden of tracking how Point-to-Point customers are fulfilling their obligations on an hourly basis. If hourly service were provided for the Capacity Based Ancillary Services, there would be a potential impact on reliability should the monitoring of adequacy of reserves not be effective. The rates produced by this process are summarized in Figure 2-8 and detailed in Attachment 3.

Figure 2-10

Rates for Capacity Based Ancillary Services		
Services	**Rate ($/MW/month)**	
	2013	**2014**
Regulation	216.73	217.06
Load Following	775.66	776.85
Operating Reserve – Spinning	166.33	166.58
Operating Reserve – Supplemental (10 minute)	331.32	331.83
Operating Reserve – Supplemental (30 minute)	280.80	281.23

2.3.2 Non-Capacity Based Ancillary Services

Non-capacity Based Ancillary Services are:

- Scheduling, System Control and Dispatch (Schedule 1 in Attachment 1)
- Reactive Supply and Voltage Control Service (Schedule 2 in Attachment 1)
- Energy Imbalance Service (Schedule 4 in Attachment 1)

The methodology for developing transmission rates (outlined in Figure 2-1) is also to determine rates for these services. Rates for Scheduling, System Control and Dispatch Service are derived from the transmission review requirements in Section 2.2 of this report. The remaining two Non-capacity Based Ancillary Services are considered below.

2.3.2.1 Reactive Supply and Voltage Control Service

Reactive power must be appropriately distributed across the Transmission System since it cannot be transported efficiently. If there was no reactive power available from generation, Static Var Controls (SVC) of a wide range of sizes would have to be strategically deployed across the grid to provide this Ancillary Service.

The total system requirement for this service from generators on the system is based on the reactive power output of in-province generators at the time of system peak plus an additional MVAR capability held in reserve to ensure dynamic system security. The total revenue requirement for this service is determined by applying estimated embedded unit cost to the total system requirement for reactive power. Details of this are provided in Attachment 3.

Whether purchasing Point-to-Point or Network Service, all Transmission Customers use this service, since without this service no transactions can occur. Therefore, the revenue requirement is allocated to the two types of use. This allocation is done on the same basis as the allocation of the revenue requirement associated with the Transmission System. This allocation to Point-to-Point and Network Services is explained in Section 2.2. The respective usages are the five-year average of export reservations and an average of the 12 monthly peak Network Loads coincident with the system peak.

The rate calculations are performed in the same manner as used in the determination of Transmission Service rates discussed in Section 2.2. The revenue requirement for this service for users of Point-to-Point Service is divided by the five-year average of export reservation quantity. The revenue requirement of this service for users of Network Service is divided by the average of the 12 monthly non-coincident peak net demands for Network Service. The Appalachian pricing approach (explained in Section 2.2.3) is applied to this service in the same fashion as it is applied to the Point-to-Point Service. The rates for this service are shown in Figure 2-11.

Figure 2-11

Reactive Supply and Voltage Control Service Rates			
Point-to-Point Services	**Units**	**Rate**	
		2013	**2014**
Yearly	$/MW-yr	2,576.61	2,579.68
Monthly	$/MW-m	214.72	214.97
Weekly	$/MW-w	49.55	49.61
On-Peak Daily	$/MW-d	9.91	9.92
Off-Peak Daily	$/MW-d	7.06	7.07
On-Peak Hourly	$/MW-h	0.62	0.62
Off-Peak Hourly	$/MW-h	0.29	0.29
Network Service	$/MW-m	182.48	182.76

2.3.2.2 Energy Imbalance

Energy imbalance is a service that has no predictable required quantity and the cost of providing the service fluctuates with the real time cost of producing energy. For these reasons, this service is priced uniquely using hourly marginal costs. NS Power does not propose any changes to this mechanism in this submission.

2.4 Summary of Rates

Rates proposed for all OATT services included in this Application are set out in Figure 2-12. For ease of comparison, the rates for all services are provided in the common units of $/MW/month.

Figure 2-12

Rates for Services in NS Power's Open Access Transmission Tariff

Services	Schedule in OATT	2013 ($/MW/month)	2014 ($/MW/month)
Scheduling, System Control, and Dispatch Service	Schedule 1		
Point-to-Point		403.24	416.45
Network		342.76	353.98
Reactive Supply and Voltage Control	Schedule 2		
Point-to-Point		214.72	214.97
Network		182.48	182.76
Regulation	Schedule 3	216.73	217.06
Load Following	Schedule 3	775.66	776.85
Energy Imbalance Service	Schedule 4	variable as described in OATT	variable as described in OATT
Operating Reserve – Spinning	Schedule 5	166.33	166.58
Operating Reserve – Supplemental (10 minute)	Schedule 6	331.32	331.83
Operating Reserve – Supplemental (30 minute)	Schedule 6	280.80	281.23
Point-to-Point Service	Schedule 7	4,670.50	4,989.66
Network Integration Service	Schedule 10	3,969.93	4,241.21

2.5 Development of NS Power's Transmission Revenue Requirement

2.5.1 Overview

The transmission revenue requirement used in the development of the OATT rates includes:

- Depreciation
- Interest
- Return on Equity
- Taxes (income, grants in lieu, large corporation tax, etc.)
- Operating & Maintenance
- Appropriate portions of Corporate Overheads
- Fixed Cost Deferral associated with loss of the Port Hawkesbury mill's load, reduction of Bowater's load, and migration of a portion of Bowater's load from the ELI 2P-RTP Tariff to the Load Retention Tariff

Each of these is discussed in more detail below. The first four items above are derived from the total transmission assets.

2.5.2 Total Transmission Assets

NS Power's average transmission assets have a gross plant value (before depreciation) of $911.4 million in 2013 and $969.4 million in 2014, as shown in Attachment 2. In 2013, this includes $798.3 million of Transmission assets, $74.2 million of General Property assets, and $38.8 million of other assets such as deferred charges, materials inventory and net receivables which are assigned to the transmission function in the Cost of Service Study (COSS). In 2014, this includes $854.2 million of Transmission assets, $79.2 million of General Property assets, and $36.0 million of other assets such as deferred charges, materials inventory and net receivables which are assigned to the transmission function in the COSS.

Consistent with the methodology approved by the Board, the following adjustments are made for the purpose of developing the OATT revenue requirement:

- Generator step-up transformers have been excluded ($17.0 million in 2013 and $16.9 million in 2014).
- Transmission lines that are radial-to-generation have been excluded ($31.6 million in 2013 and $33.6 million in 2014).
- Portions of substations (such as breakers) that are radial-to-generation have been excluded ($7.2 million in 2013 and $7.1 million in 2014).

With these adjustments, NS Power's total transmission assets for the purposes of the OATT are $911.4 million in 2013 and $969.4 million in 2014.

2.5.2.1 Depreciation

The depreciation rates, approved by the Board in 2011[2] were applied to the transmission assets and general property assets to develop a total depreciation charge. The composite rates being used for 2013 and 2014 are:

- Transmission Assets 2.35 percent
- General Property 8.16 percent

The total value of average depreciable transmission assets in 2013 is $785.7 million ($911.4 million minus $38.8 million for deferred charges, materials inventory and net receivables, minus $74.2 million for General Property, minus $12.6 million for non-depreciable land). The total value of average depreciable transmission assets in 2014 is $841.6 million ($969.4 million minus $36.0 million for deferred charges, materials inventory and net receivables, minus $79.2 million for General Property, minus $12.6

[2] NSPI Depreciation Study Application, UARB Order, NSUARB-NSPI-P-891, May 11, 2011.

million for non-depreciable land). The depreciation charge for OATT is calculated as follows:

- [Transmission Assets * Transmission Depreciation Rates] +
  [General Property Assets * General Property Depreciation Rates] + Tax Effects

- Year 2013 = $785.7 million * 0.0235 + $74.2 * 0.0816 + (1.0) = $24.1 million

- Year 2014 = $841.6 million * 0.0235 + $79.2 * 0.0816 + (1.2) = $25.6 million

- With portions of this excluded (associated with generator step-up transformers, etc.), the net charge for the purpose of OATT is $24.1 million in 2013 and $25.6 million in 2014.

2.5.3 Interest, Return on Equity and Taxes

The interest charges include the amortization of defeasance costs. The forecast Capital Structure and Return on Equity (ROE) is 37.5 percent and 9.20 percent, respectively for 2013 and 2014. The Weighted Average Cost of Capital (WACC), adjusted to reflect taxes, in 2013 is 10.42 percent and 10.47 percent in 2014 as shown in Tables E1-1 (2013 and 2014) below.

Applying this WACC to the net book value of the total transmission, associated general property assets and associated deferred charges, working capital and receivables, the total charge for interest, ROE and taxes is $54.6 million in 2013 and $59.5 million in 2014.

With this approach, the ROE and the capital structure are inputs to the process.

1 **Figure 2-13**

TABLE E1-1

Nova Scotia Power Inc.
2013 Transmission Tariff WACC Rate
Millions of dollars

1) Interest (Carrying Cost)				
a) Weighted Average Cost of Capital - Pretax				
	Proportion	Cost	Extended	
ST Debt	6.3%	4.07%	0.26%	
LT Debt	52.5%	7.30%	3.83%	
Preferred	3.7%	6.02%	0.22%	
Common	37.5%	9.20%	3.45%	
	100.0%		7.76%	
WACC - pretax cost				7.76%
b) Additional income tax for common equity				
Extended equity cost			3.45%	
Effective tax rate (excluding surtax)			31.0%	
Income tax			1.55%	
WACC - equity tax cost				1.55%
c) Large Corporations Tax				
Provincial capital tax		0.000%		
Federal capital tax		0.000%		
Ave. NPV - Transmission		$451.065		
Ave. NPV - assigned GP		34.981		
Ave. Deferred Chgs & W/C		38.589		
NPV - Total Transmission		$524.634		
Provincial capital tax		$0.00		
Federal capital tax		$0.00		
Total		$0.00		
Percentage of NBV		0.00%		
WACC - Large Corporations Taxes				0.00%
d) Grants in Lieu of Property Tax				
Total 2013 Forecasted Expense			$37.500	
Transmission % of Total Plant			15.4%	
Transmission Allocated Amount			$5.8	
Percentage of NBV			1.10%	
WACC - Grants in Lieu of Property Tax				1.10%
Total WACC - Interest / Carrying Cost				**10.42%**

1 **Figure 2-13 continued**

TABLE E1-1

Nova Scotia Power Inc.
2014 Transmission Tariff WACC Rate
Millions of dollars

1) Interest (Carrying Cost)				
a) Weighted Average Cost of Capital - Pretax				
	Proportion	Cost	Extended	
ST Debt	6.7%	6.07%	0.41%	
LT Debt	52.1%	7.20%	3.75%	
Preferred	3.7%	6.02%	0.22%	
Common	37.5%	9.20%	3.45%	
	100.0%		7.83%	
WACC - pretax cost				7.83%
b) Additional income tax for common equity				
Extended equity cost			3.45%	
Effective tax rate (excluding surtax)			31.0%	
Income tax			1.55%	
WACC - equity tax cost				1.55%
c) Large Corporations Tax				
Provincial capital tax		0.000%		
Federal capital tax		0.000%		
Ave. NPV - Transmission		$497.131		
Ave. NPV - assigned GP		34.827		
Ave. Deferred Chgs & W/C		36.777		
NPV - Total Transmission		$568.735		
Provincial capital tax		$0.00		
Federal capital tax		$0.00		
Total		$0.00		
Percentage of NBV		0.00%		
WACC - Large Corporations Taxes				0.00%
d) Grants in Lieu of Property Tax				
Total 2014 Forecasted Expense			$38.500	
Transmission % of Total Plant			16.1%	
Transmission Allocated Amount			$6.2	
Percentage of NBV			1.09%	
WACC - Grants in Lieu of Property Tax				1.09%
Total WACC - Interest / Carrying Cost				**10.47%**

2
3

2.5.4 Operating Costs

For 2013 and 2014, operating costs total $26.6 million and $26.8 million, respectively. They include all transmission-related O&M associated with the following departments:

- Transmission Operations and Maintenance
- Transmission and Distribution Asset Management
- Control Centre Operations

2.5.5 Corporate Overheads

These costs include corporate functions such as Executive, Finance, IT, Regulatory Affairs, Legal and Procurement. Based on estimates prepared by NS Power, the costs of each group are assigned to the Power Production, Customer Operations and Marketing and Sales groups. The portion assigned to Customer Operations is split between Transmission and Distribution and the Transmission portion ($5.5 million in 2013 and $5.7 million in 2014) is included in the OATT.

2.6 Embedded Cost of Ancillary Services

2.6.1 Methodology

The approach used to calculate the cost of Ancillary Services is described below and illustrated in Attachment 4.

This approach is similar to the approach used by NB Power to develop Ancillary Service charges based on embedded costs, for comparison to the charges it was proposing based on proxy units. Following the NB Power methodology, the costs of providing each Ancillary Service are derived from the fixed costs of each unit that is expected to provide such service. The derivation of charges for each service is described in the following tables:

2.6.1.1 Table E4-1: Generating Unit Specific Fixed Charge Summary

Table E4-1 in Attachment 4 details the total fixed costs of each of the generating units. Operating costs, depreciation, interest, return on equity and taxes are shown for each generating unit and then divided by the respective net book value to produce the respective fixed charge rate. The net book value and the fixed charge rates are used in subsequent schedules.

2.6.1.2 Table E4-2: Voltage Control and Reactive Supply

Table E4-2 in Attachment 4 details the cost of providing Voltage Control and Reactive Supply service to the NS Power Transmission System from NS Power's generating units. This table:

- calculates the percent of generator (i.e. the actual generator, not the whole generating station) and exciter capital costs used to supply VARs (the auxiliary device needed to develop and control voltage and reactive power, without which a synchronous generator cannot produce power)

- applies fixed charge rates to the generator and exciter capital costs to calculate annual fixed costs

- calculates annual energy consumption costs to operate the exciter

- sums generator capital, exciter capital and exciter energy consumption costs

- allocates a portion of this total to the provision of the service based on the ratio of the total reactive requirement to the total reactive capability

2.6.1.3 Table E4-3: Regulation

Table E4-3 in Attachment 4 details the cost of providing Regulation Service. This service is provided by generating units that are equipped with Automatic Generation Control (AGC) equipment which allows these units to respond to changes in load that occur on a 10-minute to 10-minute interval basis. This schedule calculates the ability to provide the service based on the time that each generating unit was called upon to provide AGC, the regulating capacity of each generating unit, and the ramp rate of each generating unit. The calculated ability of each unit is used to produce a percentage participation for each unit. The participation percentages are then multiplied by the respective net book values and fixed charge rates to produce annual costs, weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

2.6.1.4 Table E4-4: Load Following

Table E4-4 in Attachment 4 details the cost of providing Load Following Service, which represents the requirement of generation output to follow load from hour to hour. The expected provision of the service by each unit is used to produce percentage participation for each unit. The participation percentages are then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

2.6.1.5 Table E4-5: Spinning Reserve Cost

Table E4-5 in Attachment 4 details the cost of Spinning Reserve. This service is provided by generating units that have the ability to adjust their contribution to NS Power’s net generation in response to commands from the system operator. These units must be running and synchronized to the Transmission System. This is a service that must respond within 10 minutes of a contingency (such as the loss of a generator because of a forced outage). The methodology evaluates the ability of each unit to respond to commands from the system operator.

There are two ways in which a generator may be able to respond to such a command from the System Operator. In the first instance, the net output of the generator can be increased within ten minutes. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rate of each unit. In the second instance, the System Operator can, within ten minutes, curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculated ability of each unit is used to produce a percentage contribution for each unit. The contribution percentages are then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

2.6.1.6 Table E4-6: 10 Minute Reserve Cost

Table E4-6 in Attachment 4 details the cost of Supplemental 10 Minute Reserve Service. This service is provided by generating units that have the ability to adjust their contribution to NS Power’s net generation in response to commands from the System Operator. These units are not required to be running and synchronized to the Transmission System. This is also a service that must respond within 10 minutes of a contingency. The methodology evaluates the ability of each unit to respond to commands from the System Operator.

There are two ways in which a generator may be able to respond to such a command from the System Operator. In the first instance, the net output of the generator can be increased within ten minutes. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rate of each unit. In the second instance, the system operator can, within ten minutes, curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculation of the weighted annual cost for the provision of this service is similar to the calculation of the cost for Operating Reserve – Spinning Service.

The calculated ability of each unit is used to produce a percentage contribution for each unit. The contribution percentages is then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

2.6.1.7 Table E4-7: 30 Minutes Reserve Cost

Table E4-7 in Attachment 4 details the cost of Supplemental 30 Minute Operating Reserve Service. This service is provided by generating units that have the ability to adjust their contribution to NS Power's net generation in response to commands from the system operator. These units are not required to be running and synchronized to the Transmission System. This is a service that must respond within 30 minutes of a contingency. The methodology evaluates the ability of each unit to respond to commands from the system operator.

There are two ways in which a generator may be able to respond to such a command from the system operator. In the first instance, the net output of the generator can be increased. The calculation of the ability to respond considers the capacity factor, operating limits, and the ramp rates of each unit. In the second instance, the system operator can curtail a recallable export of energy from that generator to replace lost generation in Nova Scotia.

The calculation of the weighted annual cost for the provision of this service is similar to the calculation of the cost of Spinning Reserve and Supplemental 10 Minute Operating Reserve Service.

The calculated ability of each unit is used to produce a percentage contribution for each unit. The contribution percentages are then multiplied by the respective net book values and fixed charge rates to produce annual costs weighted by the ability of each unit to provide the service. The sum of the weighted costs produces a total weighted annual cost per kW of service.

3 RATE VARIANCE ANALYSIS

The Open Access Transmission Tariff (OATT) rates have not been updated since approved by the Board in 2005. The following information provides a comparison of the changes to the Transmission and Ancillary Services rates in the OATT between 2005 – 2013/2014 and identifies the key drivers of the variances.

Figure 3-1

Rate Variance Analysis					
Rate	**2005**	**2013**	**2014**	**Percentage Change (%)**	
	($/MW/month)			**2013/2005**	**2014/2013**
Transmission					
Point to Point	3,580.88	4,670.50	4,989.66	30.4	6.8
Network	2,782.20	3,969.93	4,241.21	42.7	6.8
Scheduling, System Control and Dispatch					
Point to Point	232.84	403.24	416.45	73.2	3.3
Network	181.18	342.76	353.98	89.2	3.3
Reactive Power					
Point to Point	293.54	214.72	214.97	(27.3)	0.1
Network	227.99	182.48	182.76	(29.0)	0.2
Capacity-based Ancillary Services					
Regulation	78.60	216.73	217.06	175.7	0.2
Load Following	449.80	775.66	776.85	72.4	0.2
Spinning (10 minute)	91.91	166.33	166.58	81.0	0.2
Supplemental (10 minute)	203.94	331.32	331.83	62.5	0.2
Supplement (30 minute)	195.54	280.80	281.23	43.6	0.2

Prices of OATT services are determined by dividing a revenue requirement, associated with the provision of OATT service, by the amount of total system usage. Thus, changes in rates are an outcome of a combined effect of changes in total revenue requirement and changes in usage. Both of these factors were drivers behind changes in OATT rates since 2005.

- The overall system usage as measured in monthly coincident kW demand for combined Point to Point and Network Services has decreased by 10 percent. This means that absent any change in the revenue requirement, rates for all OATT services would increase by 11 percent. The decrease in system usage is primarily due to reduction in pulp and paper load on NS Power's system.

- The individual OATT services show diverse changes in their revenue requirements due to the diversity of their underlying cost drivers. Apart from upward unit cost pressures of employed capital and labour resources in delivery of OATT services, the amount and mix of these resources have also changed in response to changes in operational characteristics of the NS Power's system.

- The unit costs of employed resources have increased for several reasons.

  - Investment in NS Power's transmission assets has increased gross plant value in 2013 over 2005 by 39.2 percent. NS Power is also proposing an increase to gross plant in 2014 of 7.0 percent over 2013.

  - Depreciation rates used in the 2005 calculation for transmission and general property assets were 2.58 percent and 6.22 percent, respectively. The depreciation rates used in 2013 and 2014 for transmission and general property assets were 2.35 percent and 8.16 percent, respectively.

  - NS Power's total operating costs increased 53.3 percent in 2013 over 2005. Operating costs, in 2014, will also increase 1.4 percent over 2013.

  - The adjusted weighted average cost of capital (WACC) used in 2005 was 12.22 percent compared to 10.42 percent in 2013 and 10.47 in 2014.

- The system operational factors, which affect the amount of generation resources employed in the delivery of generation-based ancillary services, have changed.

  - The increase in the presence of wind generation from 1 MW in 2005 to 300 MW in 2011 caused an increase in the demand for regulation and load following services in spite of a 10 percent overall decline in the total system load. More generation resources are now dedicated to the delivery of these services than in 2005.

- Changes in relative share of NS Power’s contribution to the combined generation of the NPCC Maritime area have increased NS Power’s obligations in the delivery of spinning reserves and supplemental reserves.

- Changes in the overall load versus generation configuration on NS Power’s system with more generation coming off power stations in Halifax, closer to the load centre, had the effect of lessening the transmission system load and thus reducing the requirement for reactive power.

4 EMBEDDED COST RECOVERY MECHANISM

As identified in Section 11.2.3 of the General Rate Application (GRA) Evidence, NS Power seeks amendments to the ratemaking framework of the Open Access Transmission Tariff (OATT) to provide an Embedded Cost Recovery Mechanism that will protect the interests of other customers if Municipal Electric Utilities (MEU) opt for third-party electricity supply.

4.1 Introduction

NS Power introduced its OATT in 2005 and legislation enabling MEU customers to have a choice of seeking alternative suppliers for their energy needs came into effect in 2007. Since that time, the tariff has seen little use.

NS Power remains uncertain about future OATT use. As such, for the 2013 GRA, NS Power has assumed that the wholesale municipal customers will continue taking bundled service.

However, the ability of these customers to depart from bundled service imposes a risk on NS Power's remaining customers. The Company planned and built its system within a regulated environment based on the obligation to provide bundled generation and transmission services to all classes of customers within the province. The regulatory framework in which NS Power operates requires all customers to share the cost of building and operating the electrical system in return for bundled service. Until wholesale municipal customers choose alternative supply, NS Power continues to have this obligation to serve and must continue to plan and invest in the system with wholesale municipal customers' load needs in mind. The risk of transferring costs to other customers arises because of the potential that existing NS Power generation assets, built in part to serve the municipal customers, will be at least partially "stranded," absent the load of the departing customers.

These assets were built in part to fulfill NS Power's obligation to serve the municipal customers. As NS Power has to anticipate the ongoing supply of these customers, the Company proposes that the departing customers have an ongoing obligation to pay their share of the cost of these assets, which should survive the customers' departure from NS Power bundled service rates.

4.2 FERC Exit Fee Principles

NS Power's OATT is modeled on the pro forma tariff issued by the US Federal Energy Regulatory Commission (FERC), which includes a provision for the Transmission Provider to seek recovery of stranded costs from Transmission Customers using the tariff. In its Orders 888 (1996) and 888a (1997), FERC set out what it called "transition cost provisions" regarding stranded costs.

The transition provisions clearly indicate that utilities are entitled to "the recovery of legitimate, prudent, and verifiable stranded costs"[3] created as a result of the eligible customer leaving the utility's generation system using the OATT. FERC is clear that the transition costs should fall on departing customers in the form of an exit fee that is calculated upfront, but paid either upfront in a lump sum or over time. The upfront calculation ensures that customers can make an informed decision regarding departure.

FERC requires a so-called "lost revenues" approach in the determination of embedded cost obligations. The approach requires the determination of a one-time annual snapshot of the forgone contribution to the recovery of its bundled service costs, net of OATT revenues from the departed customers and net of off-system sales revenue opportunities created by freed-up generation capacity and energy. The annual forgone contribution is then aggregated over an appropriate number of years representing the length of a departing customer's residual obligation, to yield the total amount of embedded cost obligation.

[3] Federal Energy Regulatory Commission, Order No. 888, April 24, 1996.

Such an approach offers the benefit of simplicity and cost certainty to departing customers. It manages internally the obligation of the utility to mitigate its loss through the competitive market value estimate.

The key question arising from the FERC methodology is establishing the length of a departing customer's residual obligation. This is a function, primarily, of the extent to which the utility planned and invested on the expectation of providing on-going service to the departing customer. As such, it is a matter of local fact. A case where customers have expiring contracts, for example, could be seen as precisely limiting the term of a utility's reasonable service expectation. Cases where the utility has a perennial service obligation would present a different service obligation. In Nova Scotia, there are no contracts with specified years of service between NS Power and the MEU. In summary, the Board should determine the balance of cost sharing of stranded costs among bundled and departing customers.

4.3 The Need for Embedded Cost Obligation Recovery

Exit fees have not been included in NS Power's OATT to this point. This reflects the following historical factors:

- prevailing market conditions that historically made an exit fee provision unnecessary
- short-run marginal costs that were higher than bundled rates in 2005
- deferral of the exit fee issue in the May 2005 OATT Consensus Proposal

In particular, it was NS Power's view in 2005 that, in a world of growing domestic load and relatively profitable export opportunities, departing customers would not impose a material risk on remaining customers. That is, freed-up generation could be profitably sold until the surplus was, relatively quickly, consumed by an expanding domestic market.

Those conditions have now changed. As described in Figure 3-4 of the Load Forecast section of the 2013 GRA Direct Evidence, NS Power is no longer forecasting material domestic load growth. In fact, since 2005 load has decreased from 12,338 GWh to a forecast of 10,721 GWh in 2013 due to economic factors significantly affecting industrial customers coupled with effective Demand Side Management programs for all customer classes. In addition, short run marginal costs are about $50/MWh below unit revenues, and export opportunities for freed-up generation are minimal. Figure 3-4 of the Load Forecast evidence shows export sales from 2000 to 2005 ranged from 177-530 GWh while the forecast for 2013 is 30 GWh. As such, a departing customer would leave a significant embedded cost obligation behind and NS Power's ability to mitigate it has decreased. NS Power agrees with FERC: these costs should be borne by the departing customer in the form of an exit fee and not transferred to remaining bundled service customers.

4.4 Proposed Approach to Embedded Cost Recovery Amount Determination

NS Power is proposing to calculate the Embedded Cost Obligation of each departing customer in a manner that is generally consistent with the "lost revenues" approach required by FERC. NS Power is not within FERC's jurisdiction, and believes that the minor modifications that it is proposing to the FERC methodology are (a) more appropriate in the NS Power case; and (b) supportive of NS Power's reciprocity obligations.

Under the lost revenues approach, the embedded cost obligation represents a net present value of a stream of identical forgone annual cost contributions over a limited number of years. The annual forgone cost contribution is determined on the basis of customer's historical annual consumption priced at the most recent rates, made up of the lesser of:

1. the average annual contribution to fixed costs that would have been made by the departing customer had it remained on the bundled service; or

2. the revenue expected from the departing customer under the bundled service, had it not left, net of the revenue expected from the customer under the open access service less the higher of competitive market value of released capacity and energy or avoided fuel costs of serving departed customer's load.

NS Power is proposing that the term of the calculation be set at five years in reflection of the fact that NS Power's municipal customers are served on perennial rates with no defined end to NS Power's service obligation.

4.4.1 Proposed Formula for the Determination of Embedded Cost Obligation

Embedded Cost Obligation = FAM Obligation + Forgone Future Revenue

FAM Obligation = FAM AA Amount + FAM BA Amount + Current Year Fuel Cost Imbalance

Forgone Future Revenue = (Base Cost Rate Revenue Estimate – Competitive Market Value) * Length of Obligation of 5 years

Base Cost Rate Revenue Estimate = Bundled Service Revenue – OATT Revenue – BUTU Revenue (if applicable)

Competitive Market Value = Higher of Avoided Costs or Market Price-based Revenue

4.4.2 Embedded Cost Obligation Recovery

NS Power proposes that the obligations arising from the FAM and forgone future revenue be treated separately. The FAM is a non-recurring cost obligation that requires a separate and transparent treatment to comply with the reporting requirements under the FAM. NS Power proposes that a departing customer settles the fuel cost imbalance on a pro rata basis upon its departure.

The forgone future revenue is concerned with costs embedded in base cost rates for recovery of future recurring costs. NS Power proposes that a departing customer have three choices regarding payment for this obligation.

1. lump sum payment of the entire amount calculated as a present value of the expected revenue stream, priced using current rates, during the next 5 years

2. amortization of the lump sum payment over 5 years – NS Power will collect this amount by charging a customer a monthly fee equal to the sum of the expected revenue stream during the next 5 years.

3. surcharge on the customer's transmission rate in $/kW determined as a ratio of nominal lump sum amount and expected total monthly kW usage in the next 5 years

4.4.3 Inclusion of the Embedded Cost Recovery Mechanism in the OATT

Sections 26.0 and 34.5 of the OATT provide for the recovery of stranded costs when wholesale customers use the OATT to exit bundled service supply:

> 26.0/34.5 Stranded Cost Recovery
>
> The Transmission Provider reserves the right to seek recovery of stranded costs from the Transmission Customer pursuant to this Tariff. However, the Transmission Provider must separately file any proposal to recover stranded costs with the Board.[4]

NS Power proposes to include the methodology to calculate the embedded cost recovery mechanism in its OATT as Attachment H, found in Attachment 5 of this document.

[4] NSPI Application for Approval of an Open Access Transmission Tariff, UARB Order, NSUARB-NSPI-P-880, May 31, 2005.

In addition to the calculation formula, NS Power also proposes a provision for the preparation of an estimate of the potential embedded cost recovery fee. While it is difficult to quantify an embedded cost obligation until a wholesale customer formally provides notice of their intention to use an alternate energy supplier, a customer considering competitive market choices will have difficulty making an appropriate business decision without first knowing the value of the embedded cost recovery fees they might incur. To mitigate this difficulty, when requested and provided with a detailed scenario, NS Power will provide an estimate of expected embedded cost obligations to a wholesale municipal customer, using the methodology described above in Sections 4.4.1 and 4.4.2. Upon receipt of a notice of intent to take alternate supply, the estimate will be updated to reflect current conditions and a recovery fee will be determined. The specific terms and conditions for payment of the fee will be as determined by the Board in its decision on this filing.

For illustrative purposes, NS Power has calculated how much the embedded cost obligation would be if the MEU were to choose to use the OATT to take 100 percent of their energy from a third party supplier. Based on the proposed methodology, the embedded cost obligations attributable to these MEUs would be approximately $28.3 million for departure in 2013 and $32.3 million in 2014.

4.4.4 Accounting Treatment of the Embedded Cost Recovery Mechanism revenues

NS Power proposes that the embedded cost obligation be treated as a receivable or regulatory asset on NS Power's balance sheet repaid based on the embedded cost payment arrangement selected by the customer.

5 CONCLUSION

The OATT came into effect at the end of a period of relative price stability for the utility and its customers. The period was typified by robust system load growth and high avoided fuel costs. In those circumstances it was reasonable to expect that a departure of the municipal class load from the NS Power system would not cause harm to other customers.

In the seven year period that has passed since the OATT was approved in 2005 the operating environment of NS Power has undergone significant changes. The system experienced load growth containment through DSM programs, and the loss of significant load due to the economic challenges faced in the pulp and paper industry. At the same time the utility's operating costs, primarily the cost of fuel and purchased power, have increased considerably. Increases in the cost of fuel burned in NS Power's generation plants, coupled with new provincial requirements for renewable energy generation, gave rise to a long-term cost mitigation strategy through the gradual replacement of some coal-fired generation with renewable generation. The company has made significant investments in generation and transmission assets on behalf of its all bundled service customers including MEU.

The OATT rates have fallen significantly below the costs of OATT services since they were set in 2005. The underpriced OATT services combined with the absence of embedded cost recovery mechanism make for an unfair rate environment wherein eligible customers for OATT services might escape responsibility for the costs of prudent investments made by the company on their account.

The OATT should be updated using the approved pricing methodology. Also, it is no longer appropriate to forgive responsibility for stranded costs from departing OATT customers, under the current economic and ratemaking circumstances. Such an approach leaves a heavy burden on the shoulders of the remaining bundled service customers, and would amount to an unfair ratemaking treatment. NS Power respectfully requests approval of the proposed Embedded Cost Recovery Mechanism.

Open Access Transmission Tariff

2013 Schedules

SCHEDULE 1: SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Point-to-Point Transmission Service:

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $4,838.94/MW of Reserved Capacity per year
Monthly	$403.24/MW of Reserved Capacity per month
Weekly	$93.06/MW of Reserved Capacity per week
On-Peak Daily	$18.61/MW of Reserved Capacity per day
Off-Peak Daily	$13.26/MW of Reserved Capacity per day
On-Peak Hourly	$1.16/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.55/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

Network Integration Transmission Service:

$342.76/MW of Network Integration Transmission Service per month.

SCHEDULE 2: REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider's transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission system. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

Point-to-Point Transmission Service:

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $2,576.61/MW of Reserved Capacity per year
Monthly	$214.72/MW of Reserved Capacity per month
Weekly	$49.55/MW of Reserved Capacity per week
On-Peak Daily	$9.91/MW of Reserved Capacity per day
Off-Peak Daily	$7.06/MW of Reserved Capacity per day
On-Peak Hourly	$0.62/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.29/MW of Reserved Capacity per hour

(On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.)

Network Integration Transmission Service:

$182.48/MW of Network Integration Transmission Service per month.

SCHEDULE 3: REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Regulation (Point-to-Point Transmission Service):</u>

The minimum period for which this service is available from the Transmission Provider is one day.

Regulation (Point-to-Point Transmission Service)	
Delivery Period	**Charge($)**
Yearly	One twelfth of $2,600.70/MW of Reserved Capacity per year
Monthly	$216.73/MW of Reserved Capacity per month
Weekly	$50.01/MW of Reserved Capacity per week
Daily	$7.13/MW of Reserved Capacity per day

Regulation (Network Integration Transmission Service):

$216.73/MW of Network Integration Transmission Service per month.

Load Following (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Load Following (Point-to-Point Transmission Service)	
Delivery Period	**Charge($)**
Yearly	One twelfth of $9,307.88/MW of Reserved Capacity per year
Monthly	$775.66/MW of Reserved Capacity per month
Weekly	$179.00/MW of Reserved Capacity per week
Daily	$25.50/MW of Reserved Capacity per day

Load Following (Network Integration Transmission Service):

$775.66/MW of Network Integration Transmission Service per month.

Customer Obligations for Self-Supply and Third-Party Supply:

The customer obligation for self-supply or third-party supply of Regulation is equal to 3.5 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.5 percent of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 9.1 percent of Reserved Capacity for Point-to-Point Transmission Service and 9.1 percent of Network Load for Network Integration Transmission Service.

SCHEDULE 4: ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

<u>Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:</u>

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Dispatchable Generators:</u>

For Dispatchable Generators in the Transmission Provider’s Operating Area supplying load in the Transmission Provider’s Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 5: OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Point-to-Point Transmission Service:

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $1,995.92/MW of Reserved Capacity per year
Monthly	$166.33/MW of Reserved Capacity per month
Weekly	$38.38/MW of Reserved Capacity per week
Daily	$5.47/MW of Reserved Capacity per day

The minimum period for which this service is available from the Transmission Provider is one day.

Network Integration Transmission Service:

$166.33/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Spinning Reserve is equal to 2.0 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 2.0 percent of the Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

SCHEDULE 6: OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service (also referred to as Contingency Reserve – Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Operating Reserve – Supplemental (10 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Point-to-Point Transmission Service	
Delivery Period	**Charge ($)**
Yearly	One twelfth of $3,975.88/MW of Reserved Capacity per year
Monthly	$331.32/MW of Reserved Capacity per month
Weekly	$76.46/MW of Reserved Capacity per week
Daily	$10.89/MW of Reserved Capacity per day

Network Integration Transmission Service:

$331.32/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Supplemental Reserve will be equal to 8.3 percent of Reserved Capacity for Point-to-Point Transmission Service and 8.3 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Operating Reserve – Supplemental (30 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Point-to-Point Transmission Service	
Delivery Period	**Charge ($)**
Yearly	One twelfth of $3,369.64/MW of Reserved Capacity per year
Monthly	$280.80/MW of Reserved Capacity per month
Weekly	$64.80/MW of Reserved Capacity per week
Daily	$9.23/MW of Reserved Capacity per day

Network Integration Transmission Service:

$280.80/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 3.0 percent of Reserved Capacity for Point-to-Point. Transmission Service and 3.0 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NS Power resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

SCHEDULE 7: LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: one-twelfth of the demand charge of $56,046.05/MW of Reserved Capacity per year.
2. Monthly delivery: $4,670.50/MW of Reserved Capacity per month.
3. Weekly delivery: $1,077.81/MW of Reserved Capacity per week.
4. On-Peak Daily delivery: $215.56/MW of Reserved Capacity per day.
5. Off-Peak Daily Delivery: $153.55/MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

6. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7. On-Peak days for this service are defined as Monday to Friday.

SCHEDULE 8: NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: $4,670.50/MW of Reserved Capacity per month.

2. Weekly delivery: $1,077.81/MW of Reserved Capacity per week.

3. On-Peak Daily delivery: $215.56/MW of Reserved Capacity per day.

4. Off-Peak Daily Delivery: $153.55/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

5. On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $13.47/MWh.

6. Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.40/MWh.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

7. Discounts: Three principal requirements apply to discounts for transmission service as follows:

(iv) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(v) (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(vi) (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

8. On-Peak days for this service are defined as Monday to Friday.

9. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

SCHEDULE 9: REAL POWER LOSS FACTORS

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 2.78 percent. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS.

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

SCHEDULE 10: NETWORK INTEGRATION TRANSMISSION SERVICE RATE

1. The rate charged for Network Integration Transmission Service is $3,969.93/MW-m, based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

A = B x (C/D)

Where

A = the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.

B = Total redispatch costs during the month.

C = The Network Customer's load during the hours for which redispatch costs were incurred.

D = The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point- to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.

Open Access Transmission Tariff

2014 Schedules

SCHEDULE 1: SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Point-to-Point Transmission Service:</u>

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $4,997.38/MW of Reserved Capacity per year
Monthly	$416.45/MW of Reserved Capacity per month
Weekly	$96.10/MW of Reserved Capacity per week
On-Peak Daily	$19.22/MW of Reserved Capacity per day
Off-Peak Daily	$13.69/MW of Reserved Capacity per day
On-Peak Hourly	$1.20/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.57/MW of Reserved Capacity per hour

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

Network Integration Transmission Service:

$353.98/MW of Network Integration Transmission Service per month.

SCHEDULE 2: REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider's transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission system. The Transmission Customer must purchase this service from the transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

Point-to-Point Transmission Service:

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $2,579.68/MW of Reserved Capacity per year
Monthly	$214.97/MW of Reserved Capacity per month
Weekly	$49.61/MW of Reserved Capacity per week
On-Peak Daily	$9.92/MW of Reserved Capacity per day
Off-Peak Daily	$7.07/MW of Reserved Capacity per day
On-Peak Hourly	$0.62/MW of Reserved Capacity per hour
Off-Peak Hourly	$0.29/MW of Reserved Capacity per hour

(On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.)

Network Integration Transmission Service:

$182.76/MW of Network Integration Transmission Service per month.

SCHEDULE 3: REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Regulation (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Regulation (Point-to-Point Transmission Service)	
Delivery Period	**Charge($)**
Yearly	One twelfth of $2,604.69/MW of Reserved Capacity per year
Monthly	$217.06/MW of Reserved Capacity per month
Weekly	$50.09/MW of Reserved Capacity per week
Daily	$7.14/MW of Reserved Capacity per day

Regulation (Network Integration Transmission Service):

$217.06/MW of Network Integration Transmission Service per month.

Load Following (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

Load Following (Point-to-Point Transmission Service)	
Delivery Period	**Charge($)**
Yearly	One twelfth of $9,322.16/MW of Reserved Capacity per year
Monthly	$776.85/MW of Reserved Capacity per month
Weekly	$179.27/MW of Reserved Capacity per week
Daily	$25.54/MW of Reserved Capacity per day

Load Following (Network Integration Transmission Service):

$776.85/MW of Network Integration Transmission Service per month.

Customer Obligations for Self-Supply and Third-Party Supply:

The customer obligation for self-supply or third-party supply of Regulation is equal to 3.5 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.5 percent of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 9.1 percent of Reserved Capacity for Point-to-Point Transmission Service and 9.1 percent of Network Load for Network Integration Transmission Service.

SCHEDULE 4: ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

<u>Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:</u>

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Dispatchable Generators:

For Dispatchable Generators in the Transmission Provider’s Operating Area supplying load in the Transmission Provider’s Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Non-Dispatchable Generators</u>

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 5: OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Point-to-Point Transmission Service:

Point-to-Point Transmission Service	
Delivery Period	**Charge($)**
Yearly	One twelfth of $1,998.99/MW of Reserved Capacity per year
Monthly	$166.58/MW of Reserved Capacity per month
Weekly	$38.44/MW of Reserved Capacity per week
Daily	$5.48/MW of Reserved Capacity per day

The minimum period for which this service is available from the Transmission Provider is one day.

Network Integration Transmission Service:

$166.58/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Spinning Reserve is equal to 2.0 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 2.0 percent of the Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

SCHEDULE 6: OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service (also referred to as Contingency Reserve – Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Operating Reserve – Supplemental (10 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Point-to-Point Transmission Service	
Delivery Period	**Charge ($)**
Yearly	One twelfth of $3,981.98/MW of Reserved Capacity per year
Monthly	$331.83/MW of Reserved Capacity per month
Weekly	$76.58/MW of Reserved Capacity per week
Daily	$10.91/MW of Reserved Capacity per day

Network Integration Transmission Service:

$331.83/MW of the Network Integration Transmission Service per month.

Customer Obligations for Self-supply and Third-Party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Supplemental Reserve will be equal to 8.3 percent of Reserved Capacity for Point-to-Point Transmission Service and 8.3 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Operating Reserve – Supplemental (30 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

Point-to-Point Transmission Service	
Delivery Period	**Charge ($)**
Yearly	One twelfth of $3,374.81/MW of Reserved Capacity per year
Monthly	$281.23/MW of Reserved Capacity per month
Weekly	$64.90/MW of Reserved Capacity per week
Daily	$9.25/MW of Reserved Capacity per day

Network Integration Transmission Service:

$281.23/MW of the Network Integration Transmission Service per month.

Customer Obligations

The customer obligation for reserves is equal to 3.0 percent of Reserved Capacity for Point-to-Point. Transmission Service and 3.0 percent of Network Load for Network Integration Transmission Service.

Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NS Power resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

SCHEDULE 7: LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: one-twelfth of the demand charge of $59,875.87/MW of Reserved Capacity per year.
2. Monthly delivery: $4,989.66/MW of Reserved Capacity per month.
3. Weekly delivery: $1,151.46/MW of Reserved Capacity per week.
4. On-Peak Daily delivery: $230.29/MW of Reserved Capacity per day.
5. Off-Peak Daily Delivery: $164.04/MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

6. Discounts: Three principal requirements apply to discounts for transmission service as follows:

   (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

   (ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

   (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7. On-Peak days for this service are defined as Monday to Friday.

SCHEDULE 8: NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: $4,989.66/MW of Reserved Capacity per month.

2. Weekly delivery: $1,151.46/MW of Reserved Capacity per week.

3. On-Peak Daily delivery: $230.29/MW of Reserved Capacity per day.

4. Off-Peak Daily Delivery: $164.04/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

5. On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.39/MWh.

6. Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.84/MWh.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Sec tion 3 above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

7. Discounts: Three principal requirements apply to discounts for transmission service as follows:

(iv) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

(v) (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

(vi) (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

8. On-Peak days for this service are defined as Monday to Friday.

9. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

SCHEDULE 9: REAL POWER LOSS FACTORS

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 2.78 percent. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS.

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

SCHEDULE 10: NETWORK INTEGRATION TRANSMISSION SERVICE RATE

1. The rate charged for Network Integration Transmission Service is $4,241.21/MW-m, based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

A = B x (C/D)

Where

A = the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.

B = Total redispatch costs during the month.

C = The Network Customer's load during the hours for which redispatch costs were incurred.

D = The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point- to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.

FIGURE 2-1

NOVA SCOTIA POWER INC.
2013 TRANSMISSION REVENUE REQUIREMENT
(in $000s)

Asset Category	(1) Gross Plant (Note 1)	(2) Net Plant (Note 1)	(3) OM&G Expense	(4) Depreciation Expense	(5) Int., Taxes & Return Exp	(6) FCR Deferral	(7) Total Expenses
Generation Related Transmission Assets:							
Step Up Transformers	$16,980	$9,883	$346	$462	$1,029	$60	$1,897
Radial to Generation	31,561	18,369	643	859	1,913	112	3,527
Generator Breakers	7,158	4,166	146	195	434	25	800
Total Gen. Related Transmission Assets	55,699	32,418	1,135	1,516	3,376	197	6,224
Bulk Network:							
Total Equipment	855,676	492,216	17,321	22,556	51,267	3,019	94,163
Total Transmission Assets	**$911,375**	**$524,634**					
Scheduling, System Control & Dispatch (Note 2)			8,130				8,130
Total Transmission Revenue Requirement			**$26,586**	**$24,072**	**$54,643**	**$3,216**	**$108,517**

NOTE:

1. Transmission Gross and Net Plant assets include allocated share of General Property assets and other assets such as deferred charges, materials inventory and net receivables.
2. Control Centre assets and related capital charges are included in the General Property assignment to Transmission assets.

FIGURE 2-2

NOVA SCOTIA POWER INC.
2013 DEMAND ALLOCATION FACTORS
(in MW Demand)

Service	(1) Long-Term Firm Reservations	(2) Transmission System 12 CP	(3) Allocation Factors (%)	(4) Billing Determinants 12 NCP
Point-to-Point (Note 1)	16		0.96%	N/A
Network In-Province (Note 2)		1,664	99.04%	1,958
TOTAL MW	**16**	**1,664**	**100.00%**	

NOTES:
1. NSPI currently has no long-term firm reservations. However, exports have averaged 16 MW over the years 2007-2011.
2. The 1664 MW is the average of the 12 monthly Coincident System Peaks forecasted for 2013 and developed as part NS Power's 2013 Rate Application filed with NSUARB. The 1,958 MW was derived by applying an 85 percent coincidence factor to the monthly System Coincident Peaks. This coincident facor was based on 2003 system load data.

FIGURE 2-3

NOVA SCOTIA POWER INC.
2013 TRANSMISSION REVENUE REQUIREMENT ALLOCATION
UNIT COSTS

	(1)	(2)	(3)	(4)
Transmission Services	**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service	$902	16	$56,046.05	$4,670.50
Network Service	93,261	1,664	$56,046.05	$4,670.50
Total Transmission	**94,163**	**1,680**	**$56,046.05**	**$4,670.50**
Scheduling, System Control & Dispatch				
Point-to-Point Service	78	16	$4,838.94	$403.24
Network Service	8,052	1,664	$4,838.94	$403.24
Total Scheduling, System Control & Dispatch	**$8,130**	**1,680**	**$4,838.94**	**$403.24**

NOTES:
1. Point-to-Point and Network Transmission Service costs are Bulk Network Costs from Figure 2-1 and allocated using the allocation factors from Figure 2-2.
2. Scheduling, System Control & Dispatch Service costs, from Figure 2-1, are allocated using the allocation factors from Figure 2-2.

FIGURE 2-4

NOVA SCOTIA POWER INC.
RATE CALCULATION
2013 POINT-TO-POINT TRANSMISSION SERVICE

	(1)	(2)	(3)	(4)
Service Category	**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service	$902	16	$56,046.05	$4,670.50

			RATES	
			$/MW-year	**$/MW-month**
Yearly		Monthly Cost * 1000	56,046.05	4,670.50
Monthly	($/MW-m)	Yearly/12		4,670.50
Weekly	($/MW-w)	Yearly/52		1,077.81
On-Peak Daily	($/MW-d)	Weekly/5		215.56
Off-peak Daily	($/MW-d)	Yearly/365		153.55
On-Peak Hourly	($/MW-h)	Daily/16		13.47
Off-Peak Hourly	($/MW-h)	Yearly/8760		6.40

NOTES:
1. Yearly Service is available only as firm service.
2. Hourly Service is available only as non-firm service.
3. Other Services are available as firm or non-firm services.

FIGURE 2-5

NOVA SCOTIA POWER INC.
RATE CALCULATION
2013 NETWORK TRANSMISSION SERVICE

	(1)	(2)	(3)	(4)
Service Category	**Annual Cost of Service ($MW-year)**	**Monthly Cost of Service ($MW-month)**	**Coincidence Factor**	**Monthly ($MW-month) Billing Rate**
Network Service	$56,046.05	$4,670.50	85.0%	$3,969.93

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 2-6

NOVA SCOTIA POWER INC.
2014 TRANSMISSION REVENUE REQUIREMENT
(in $000s)

Asset Category	(1) Gross Plant (Note 1)	(2) Net Plant (Note 1)	(3) OM&G Expense	(4) Depreciation Expense	(5) Int., Taxes & Return Exp	(6) FCR Deferral	(7) Total Expenses
Generation Related Transmission Assets:							
Step Up Transformers	$16,881	$9,950	$320	$462	$1,042	$58.21	$1,882
Radial to Generation	33,603	19,806	637	920	2,074	$115.87	$3,747
Generator Breakers	7,116	4,194	135	195	439	$24.54	$794
Total Gen. Related Transmission Assets	57,600	33,951	1,092	1,577	3,555	199	$6,423
Bulk Network:							
Total Equipment	911,831	534,784	17,284	24,062	55,988	3,144	100,478
Total Transmission Assets	**$969,431**	**$568,735**					
Scheduling, System Control & Dispatch (Note 2)			8,386				8,386
Total Transmission Revenue Requirement			**$26,762**	**$25,639**	**$59,543**	**$3,342**	**$115,286**

NOTE:

1. Transmission Gross and Net Plant assets include allocated share of General Property assets and other assets such as deferred charges, materials inventory and net receivables.
2. Control Centre assets and related capital charges are included in the General Property assignment to Transmission assets.

FIGURE 2-7

NOVA SCOTIA POWER INC.
2014 DEMAND ALLOCATION FACTORS
(in MW Demand)

Service	(1) Long-Term Firm Reservations	(2) Transmission System 12 CP	(3) Allocation Factors (%)	(4) Billing Determinants 12 NCP
Point-to-Point (Note 1)	16		0.96%	N/A
Network In-Province (Note 2)		1,662	99.04%	1,955
TOTAL MW	**16**	**1,662**	**100.00%**	

NOTES:
1. NSPI currently has no long-term firm reservations. However, exports have averaged 16 MW over the years 2007-2011.
2. The 1664 MW is the average of the 12 monthly Coincident System Peaks forecasted for 2013 and developed as part NS Power's 2013 Rate Application filed with NSUARB. The 1955 MW was derived by applying an 85 percent coincidence factor to the monthly System Coincident Peaks. This coincident factor was based on 2003 system load data.

FIGURE 2-8

NOVA SCOTIA POWER INC.
2014 TRANSMISSION REVENUE REQUIREMENT ALLOCATION
UNIT COSTS

	(1)	(2)	(3)	(4)
Transmission Services	**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service	$964	16	$59,875.87	$4,989.66
Network Service	99,514	1,662	$59,875.87	$4,989.66
Total Transmission	**100,478**	**1,678**	**$59,875.87**	**$4,989.66**
Scheduling, System Control & Dispatch				
Point-to-Point Service	80	16	$4,997.38	$416.45
Network Service	8,306	1,662	$4,997.38	$416.45
Total Scheduling, System Control & Dispatch	**$8,386**	**1,678**	**$4,997.38**	**$416.45**

NOTES:
1. Point-to-Point and Network Transmission Service costs are Bulk Network Costs from Figure 2-6 and allocated using the allocation factors from Figure 2-7.
2. Scheduling, System Control & Dispatch Service costs, from Figure 2-6, are allocated using the allocation factors from Figure 2-7.

FIGURE 2-9

NOVA SCOTIA POWER INC.
RATE CALCULATION
2014 POINT-TO-POINT TRANSMISSION SERVICE

		(1)	(2)	(3)	(4)
Service Category		**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service		$964	16	$59,875.87	$4,989.66
				RATES	
				$/MW-year	**$/MW-month**
Yearly			Monthly Cost * 1000	59,875.87	4,989.66
Monthly		($/MW-m)	Yearly/12		4,989.66
Weekly		($/MW-w)	Yearly/52		1,151.46
On-Peak Daily		($/MW-d)	Weekly/5		230.29
Off-peak Daily		($/MW-d)	Yearly/365		164.04
On-Peak Hourly		($/MW-h)	Daily/16		14.39
Off-Peak Hourly		($/MW-h)	Yearly/8760		6.84

NOTES:
1. Yearly Service is available only as firm service.
2. Hourly Service is available only as non-firm service.
3. Other Services are available as firm or non-firm services.

FIGURE 2-10

NOVA SCOTIA POWER INC.
RATE CALCULATION
2014 NETWORK TRANSMISSION SERVICE

	(1)	(2)	(3)	(4)
Service Category	**Annual Cost of Service ($MW-year)**	**Monthly Cost of Service ($MW-month)**	**Coincidence Factor**	**Monthly ($MW-month) Billing Rate**
Network Service	$59,875.87	$4,989.66	85.0%	$4,241.21

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 3-1

NOVA SCOTIA POWER INC.
ANCILLIARY SERVICE RATE CALCULATION
2013 SCHEDULING, SYSTEM CONTROL AND DISPATCH

	(1)	(2)	(3)	(4)
Service	**Total Cost of Service (in $000s)**	**Total Usage (in MW)**	**Yearly Cost $/MW-year**	**Monthly Cost $/MW-month**
Scheduling, System Control & Dispatch	$78	16	$4,838.94	$403.24

			Rate for Services Billed Monthly	
Sched., Sys. Cntrl. & Disp. for Point-to-Point		**Services**	**$/MW-year**	**$/MW-month**
Yearly		Monthly Cost	4,838.94	403.24
Monthly	($/MW-m)	Yearly/12		403.24
Weekly	($/MW-w)	Yearly/52		93.06
On-Peak Daily	($/MW-d)	Weekly/5		18.61
Off-peak Daily	($/MW-d)	Yearly/365		13.26
On-Peak Hourly	($/MW-h)	Daily/16		1.16
Off-Peak Hourly	($/MW-h)	Yearly/8760		0.55

	Cost of Service					
	Total Cost of Service (in $000s)	**Total Usage (in MW)**	**($MW-year)**	**($MW-month)**	**Coincidence Factor**	**Rate Monthly ($MW-month)**
Sched., Sys. Cntrl. & Disp. for Network Service	$8,052	1,664	$4,838.94	$403.24	85.0%	$342.76

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 3-2

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA USAGE

	(1)	(2)	(3)	(4)	(5)
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads that Self Supply MW	Loads that Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	1,958			1,958
Load Following	0	1,958			1,958
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	1,958			1,958
Supplemental (10 Minute)	0	1,958			1,958
Supplemental (30 Minute)	0	1,958			1,958

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 2-2.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 3-3

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2013 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 87.49	58	$5,092.18	1,958	$2,600.70	$216.73	$216.73	$50.01	$7.13
Load Following	$ 120.77	151	$18,224.83	1,958	$9,307.88	$775.66	$775.66	$179.00	$25.50
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 118.42	33	$3,908.02	1,958	$1,995.92	$166.33	$166.33	$38.38	$5.47
Supplemental (10 Minute)	$ 56.41	138	$7,784.77	1,958	$3,975.88	$331.32	$331.32	$76.46	$10.89
Supplemental (30 Minute)	$ 131.95	50	$6,597.75	1,958	$3,369.64	$280.80	$280.80	$64.80	$9.23

NOTES:
1. Revenue Requirement is from Attachment 4.

FIGURE 3-4

NOVA SCOTIA POWER INC.
2013 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,329.0								
Less: Credits	0.0								
Net	4,329.0								
Point-to-Point	$41.5	16	$2,576.61	$214.72	$49.55	$9.91	$7.06	$0.62	$0.29
Network Services	$4,287.5	1,958	$2,189.72	$182.48					
		1,974							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 2-2, Col. 3.

FIGURE 3-5

NOVA SCOTIA POWER INC.
ANCILLIARY SERVICE RATE CALCULATION
2014 SCHEDULING, SYSTEM CONTROL AND DISPATCH

Service	(1) Total Cost of Service (in $000s)	(2) Total Usage (in MW)	(3) Yearly Cost $/MW-year	(4) Monthly Cost $/MW-month
Scheduling, System Control & Dispatch	$80	16	$4,997.38	$416.45

Sched., Sys. Cntrl. & Disp. for Point-to-Point		Rate for Services Billed Monthly Services	$/MW-year	$/MW-month
Yearly		Monthly Cost	4,997.38	416.45
Monthly	($/MW-m)	Yearly/12		416.45
Weekly	($/MW-w)	Yearly/52		96.10
On-Peak Daily	($/MW-d)	Weekly/5		19.22
Off-peak Daily	($/MW-d)	Yearly/365		13.69
On-Peak Hourly	($/MW-h)	Daily/16		1.20
Off-Peak Hourly	($/MW-h)	Yearly/8760		0.57

	Cost of Service					
	Total Cost of Service (in $000s)	Total Usage (in MW)	($MW-year)	($MW-month)	Coincidence Factor	Rate Monthly ($MW-month)
Sched., Sys. Cntrl. & Disp. for Network Service	$8,306	1,662	$4,997.38	$416.45	85.0%	$353.98

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 3-6

NOVA SCOTIA POWER INC.
2014 CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA USAGE

	(1)	(2)	(3)	(4)	(5)
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads that Self Supply MW	Loads that Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	1,955			1,955
Load Following	0	1,955			1,955
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	1,955			1,955
Supplemental (10 Minute)	0	1,955			1,955
Supplemental (30 Minute)	0	1,955			1,955

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 2-7.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 3-7

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2014 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 87.49	58	$5,092.18	1,955	$2,604.69	$217.06	$217.06	$50.09	$7.14
Load Following	$ 120.77	151	$18,224.83	1,955	$9,322.16	$776.85	$776.85	$179.27	$25.54
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 118.42	33	$3,908.02	1,955	$1,998.99	$166.58	$166.58	$38.44	$5.48
Supplemental (10 Minute)	$ 56.41	138	$7,784.77	1,955	$3,981.98	$331.83	$331.83	$76.58	$10.91
Supplemental (30 Minute)	$ 131.95	50	$6,597.75	1,955	$3,374.81	$281.23	$281.23	$64.90	$9.25

NOTES:
1. Revenue Requirement is from Attachment 4.

FIGURE 3-8

NOVA SCOTIA POWER INC.
2014 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,329.0								
Less: Credits	0.0								
Net	4,329.0								
Point-to-Point	$41.5	16	$2,579.68	$214.97	$49.61	$9.92	$7.07	$0.62	$0.29
Network Services	$4,287.4	1,955	$2,193.06	$182.76					
		1,971							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 2-7, Col. 3.

Based on 2011 Data **Embedded Cost of Ancillary Services**

TABLE E4-1

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
GENERATING STATION UNIT SPECIFIC FIXED CHARGE RATE SUMMARY

	Lingan	Tufts Cove	Trenton	Pt. Tupper	Pt. Aconi	Sub-Total Thermal Gen.	Wreck Cove	Annapolis Tidal Power	Other Hydro	Wind Generation	Total Hydro	Tufts Cove 4	Tufts Cove 5	Other Combustion Turbines	Total Combustion Turbines	Total Generation
Generator Nameplate Capacity kW's	600000	350000	310000	150000	185000	1595000	200000	17200	163000	1300	381500	54000	54000	204000	312000	2288500
Gross Plant Cost	$560,586,453	$206,622,625	$400,437,225	$176,000,743	$515,759,599	$1,859,406,645	$163,844,517	$36,296,878	$228,910,094	$0	$429,051,488	$50,038,216	$32,898,580	$66,027,927	$148,964,723	$2,437,422,855
Gross Plant Cost/kW	$934.31	$590.35	$1,291.73	$1,173.34	$2,787.89	$1,165.77	$819.22	$2,110.28	$1,404.36	$0.00	$1,124.64	$926.63	$609.23	$323.67	$477.45	$1,065.07
Net Plant Value	$289,258,840	$113,968,997	$260,191,452	$99,780,690	$335,540,081	$1,098,740,059	$88,241,676	$24,215,852	$167,570,300	$0	$280,027,828	$36,964,866	$26,265,982	$34,144,767	$97,375,614	$1,476,143,501
Net Plant Value/kW	$482.10	$325.63	$839.33	$665.20	$1,813.73	$688.87	$441.21	$1,407.90	$1,028.04	$0.00	$734.02	$684.53	$486.41	$167.38	$312.10	$645.03
- share of General Property Plant	$21,580,697	$8,502,870	$19,412,070	$7,444,325	$25,033,596	$81,973,559	$6,583,435	$1,806,669	$12,501,896	$0	$20,892,000	$2,757,833	$1,959,623	$2,547,434	$7,264,890	$110,130,450
- share of Deferred Chgs & W/C	$29,470,198	$11,611,361	$26,508,761	$10,165,832	$34,185,412	$111,941,563	$8,990,217	$2,467,153	$17,072,356	$0	$28,529,726	$3,766,045	$2,676,024	$3,478,729	$9,920,798	$150,392,087
Total NPV incl. GP & Deferred Chgs.	$340,309,734	$134,083,229	$306,112,284	$117,390,846	$394,759,089	$1,292,655,181	$103,815,327	$28,489,674	$197,144,552	$0	$329,449,554	$43,488,744	$30,901,628	$40,170,929	$114,561,302	$1,736,666,037
OM&G (Direct)	$28,251,811	$25,011,901	$17,248,501	$10,836,466	$11,473,423	$92,822,103	$1,359,240	$488,079	$7,715,461	$0	$9,562,780	$411,115	$0	$1,232,463	$1,643,578	$104,028,461
OM&G (Overhead)	($2,131,195)	($1,886,790)	($1,301,153)	($817,456)	($865,506)	($7,002,101)	($102,535)	($36,819)	($582,021)	$0	($721,375)	($31,013)	$0	($92,972)	($123,984)	($7,847,461)
Grants in Lieu	$4,096,064	$1,613,863	$3,684,453	$1,412,949	$4,751,431	$15,558,761	$1,249,550	$342,910	$2,372,887	$0	$3,965,347	$523,443	$371,941	$483,509	$1,378,892	$20,903,000
Depreciation (Direct)	$12,445,019	$6,446,626	$10,491,455	$4,276,818	$12,893,990	$46,553,908	$2,146,363	$656,973	$3,961,801	$0	$6,765,137	$1,666,273	$1,095,523	$1,935,847	$4,697,642	$58,016,688
Depr. (General Property)	$1,570,262	$813,409	$1,323,770	$539,632	$1,626,912	$5,873,985	$270,819	$82,894	$499,884	$0	$853,598	$210,244	$138,229	$244,257	$592,730	$7,320,312
Interest	$15,368,419	$6,055,211	$13,824,059	$5,301,382	$17,827,357	$58,376,428	$4,688,310	$1,286,596	$8,903,066	$0	$14,877,973	$1,963,956	$1,395,520	$1,814,123	$5,173,599	$78,428,000
Preferred Dividends	$1,732,837	$682,744	$1,558,706	$597,747	$2,010,090	$6,582,123	$528,621	$145,068	$1,003,848	$0	$1,677,538	$221,442	$157,349	$204,548	$583,339	$8,843,000
Corporate Taxes	$10,312,173	$4,063,032	$9,275,911	$3,557,214	$11,962,114	$39,170,444	$3,145,845	$863,303	$5,973,936	$0	$9,983,084	$1,317,810	$936,391	$1,217,272	$3,471,473	$52,625,000
Return	$11,907,057	$4,691,422	$10,710,526	$4,107,374	$13,812,178	$45,228,557	$3,632,382	$996,822	$6,897,867	$0	$11,527,071	$1,521,622	$1,081,213	$1,405,536	$4,008,372	$60,764,000
TOTAL	$83,552,447	$47,491,418	$66,816,228	$29,812,126	$75,491,990	$303,164,208	$16,918,596	$4,825,826	$36,746,730	$0	$58,491,152	$7,804,891	$5,176,166	$8,444,583	$21,425,640	$383,081,000
OM&G	7.68%	17.25%	5.21%	8.53%	2.69%	6.64%	1.21%	1.58%	3.62%		2.68%	0.87%	0.00%	2.84%	1.33%	5.54%
Depreciation	4.12%	5.41%	3.86%	4.10%	3.68%	4.06%	2.33%	2.60%	2.26%		2.31%	4.31%	3.99%	5.43%	4.62%	3.76%
Sub-Total	11.79%	22.66%	9.07%	12.64%	6.37%	10.69%	3.54%	4.18%	5.88%		5.00%	5.19%	3.99%	8.26%	5.94%	9.30%
Grants in Lieu	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%		1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
Interest	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%		4.52%	4.52%	4.52%	4.52%	4.52%	4.52%
Preferred Dividends	0.51%	0.51%	0.51%	0.51%	0.51%	0.51%	0.51%	0.51%	0.51%		0.51%	0.51%	0.51%	0.51%	0.51%	0.51%
Corporate Taxes	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%		3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
Return	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cost of Capital	12.76%	12.76%	12.76%	12.76%	12.76%	12.76%	12.76%	12.76%	12.76%		12.76%	12.76%	12.76%	12.76%	12.76%	12.76%
FIXED CHARGE RATE	**24.55%**	**35.42%**	**21.83%**	**25.40%**	**19.12%**	**23.45%**	**16.30%**	**16.94%**	**18.64%**		**17.75%**	**17.95%**	**16.75%**	**21.02%**	**18.70%**	**22.06%**

NOTES:

1. The Gross and Net Asset Values have been averaged based on actual year-end balances for 2008 and 2009.
2. OM&G and Capital Related Expenses have been based on the 2009 Compliance Filing in response to UARB's Decision on the 2009 Rate Application.
3. The percentages are calculated on "Total NPV incl. GP and Deferred Charges" since the capital-related expenses such as interest, taxes and return reflect NSPI's total capitalization.

DETAIL OF HYDRO FACILITIES

	Wreck Cove & Gisbourne	Avon	Black River	Lequille & Nict & Para	Mersey	Bear River & Sissiboo	Tusket	Roseway & Harmony	St. Margarets	Sheet Harbour	Dickie Brook	Fall River	Annapolis Tidal	Total Hydro
Installed Capacity kW's	204000	7000	22000	22000	42000	37000	2000	1000	10000	11000	4000	1000	17200	380200
Gross Plant Cost	$163,844,517	$15,733,820	$39,269,563	$21,694,384	$38,157,496	$37,055,040	$9,377,275	$17,052,201	$17,193,300	$23,108,049	$8,474,700	$1,794,269	$36,296,878	$429,051,488
Gross Plant Cost/kW	$803.16	$2,247.69	$1,784.98	$986.11	$908.51	$1,001.49	$4,688.64	$17,052.20	$1,719.33	$2,100.73	$2,118.68	$1,794.27	$2,110.28	$1,128.49
Net Book Value	$88,241,676	$12,585,934	$32,718,981	$14,905,418	$20,155,798	$25,586,491	$7,620,775	$15,557,518	$11,513,345	$17,472,686	$7,692,208	$1,761,149	$24,215,852	$280,027,828
Net Book Value/kW	$432.56	$1,797.99	$1,487.23	$677.52	$479.90	$691.53	$3,810.39	$15,557.52	$1,151.33	$1,588.43	$1,923.05	$1,761.15	$1,407.90	$736.53
- share of General Property Plant	$6,583,435	$938,997	$2,441,061	$1,112,047	$1,503,761	$1,908,928	$568,562	$1,160,698	$858,975	$1,303,582	$573,892	$131,394	$1,806,669	$20,892,000
- share of Deferred Chgs & W/C	$8,990,217	$1,282,277	$3,333,467	$1,518,590	$2,053,508	$2,606,797	$776,418	$1,585,027	$1,173,000	$1,780,148	$783,696	$179,429	$2,467,153	$28,529,726
Total NPV incl. GP & Deferred Chgs.	$103,815,327	$14,807,208	$38,493,508	$17,536,055	$23,713,066	$30,102,216	$8,965,755	$18,303,243	$13,545,319	$20,556,416	$9,049,795	$2,071,972	$28,489,674	$329,449,554
OM&G (Direct)	$1,359,240	$0	$1,210,937	$119,755	$2,896,495	$1,052,241	$0	$116,815	$1,432,686	$879,019	$7,514	$0	$488,079	$9,562,780
OM&G (Overhead)	($102,535)	$0	($91,348)	($9,034)	($218,499)	($79,377)	$0	($8,812)	($108,076)	($66,309)	($567)	$0	($36,819)	($721,375)
Grants in Lieu	$906,149	$87,017	$217,182	$119,982	$211,032	$204,934	$51,861	$94,308	$95,088	$127,800	$46,870	$9,923	$200,741	$2,372,887
Depreciation (Direct)	$2,146,363	$297,369	$553,701	$379,652	$713,858	$500,243	$164,102	$312,055	$343,866	$492,201	$177,121	$27,632	$656,973	$6,765,137
Depr. (General Property)	$158,597	$21,973	$40,914	$28,053	$52,748	$36,964	$12,126	$23,058	$25,409	$36,369	$13,088	$2,042	$48,545	$499,884
Interest	$3,399,868	$326,486	$814,866	$450,171	$791,790	$768,913	$194,584	$353,843	$356,771	$479,505	$175,855	$37,232	$753,181	$8,903,066
Preferred Dividends	$383,346	$36,812	$91,879	$50,758	$89,277	$86,697	$21,940	$39,897	$40,227	$54,066	$19,828	$4,198	$84,924	$1,003,848
Corporate Taxes	$2,281,304	$219,071	$546,773	$302,064	$531,289	$515,939	$130,565	$237,428	$239,392	$321,747	$117,998	$24,983	$505,383	$5,973,936
Return	$2,634,131	$252,953	$631,337	$348,781	$613,459	$595,734	$150,759	$274,148	$276,417	$371,508	$136,248	$28,846	$583,545	$6,897,867
TOTAL	$13,166,463	$1,241,681	$4,016,241	$1,790,181	$5,681,448	$3,682,290	$725,937	$1,442,741	$2,701,780	$2,695,907	$693,955	$134,856	$3,284,552	$41,258,032
OM&G	1.21%	0.00%	2.91%	0.63%	11.29%	3.23%	0.00%	0.59%	9.78%	3.95%	0.08%	0.00%	1.58%	2.68%
Depreciation	2.22%	2.16%	1.54%	2.32%	3.23%	1.78%	1.97%	1.83%	2.73%	2.57%	2.10%	1.43%	2.48%	2.21%
Sub-Total	3.43%	2.16%	4.45%	2.96%	14.53%	5.02%	1.97%	2.42%	12.51%	6.52%	2.18%	1.43%	4.06%	4.89%
Grants in Lieu	0.87%	0.59%	0.56%	0.68%	0.89%	0.68%	0.58%	0.52%	0.70%	0.62%	0.52%	0.48%	0.70%	0.72%
Interest	3.27%	2.20%	2.12%	2.57%	3.34%	2.55%	2.17%	1.93%	2.63%	2.33%	1.94%	1.80%	2.64%	2.70%
Preferred Dividends	0.37%	0.25%	0.24%	0.29%	0.38%	0.29%	0.24%	0.22%	0.30%	0.26%	0.22%	0.20%	0.30%	0.30%
Corporate Taxes	2.20%	1.48%	1.42%	1.72%	2.24%	1.71%	1.46%	1.30%	1.77%	1.57%	1.30%	1.21%	1.77%	1.81%
Return	2.54%	1.71%	1.64%	1.99%	2.59%	1.98%	1.68%	1.50%	2.04%	1.81%	1.51%	1.39%	2.05%	2.09%
FIXED CHARGE RATE	**12.68%**	**8.39%**	**10.43%**	**10.21%**	**23.96%**	**12.23%**	**8.10%**	**7.88%**	**19.95%**	**13.11%**	**7.67%**	**6.51%**	**11.53%**	**12.52%**

SUMMARY OF HYDRO FACILITIES

	Wreck Cove	Annapolis Tidal	Wind Generation	Other Hydro	Total Hydro
Installed Capacity kW's	200000	17200	1300	163000	381500
Gross Plant Cost	$163,844,517	$36,296,878	$0	$228,910,094	$429,051,488
Gross Plant Cost/kW	$803.16	$2,110.28	$0.00	$1,404.36	$1,124.64
Net Book Value	$88,241,676	$24,215,852	$0	$167,570,300	$280,027,828
Net Book Value/kW	$432.56	$1,407.90	$0.00	$1,028.04	$734.02
- share of General Property Plant	$6,583,435	$1,806,669		$12,501,896	$20,892,000
- share of Deferred Chgs & W/C	$8,990,217	$2,467,153		$17,072,356	$28,529,726
Total NPV incl. GP & Deferred Chgs.	$103,815,327	$28,489,674	$0	$197,144,552	$329,449,554
OM&G (Direct)	$1,359,240	$488,079	$0	$7,715,461	$9,562,780
OM&G (Overhead)	($102,535)	($36,819)	$0	($582,021)	($721,375)
Grants in Lieu	$906,149	$200,741	$0	$1,265,997	$2,372,887
Depreciation (Direct)	$2,146,363	$656,973	$0	$3,961,801	$6,765,137
Depr. (General Property)	$158,597	$48,545	$0	$292,742	$499,884
Interest	$3,399,868	$753,181	$0	$4,750,017	$8,903,066
Preferred Dividends	$383,346	$84,924	$0	$535,579	$1,003,848
Corporate Taxes	$2,281,304	$505,383	$0	$3,187,250	$5,973,936
Return	$2,634,131	$583,545	$0	$3,680,191	$6,897,867
TOTAL	$13,166,463	$3,284,552	$0	$24,807,016	$41,258,032
OM&G	1.21%	1.58%	#DIV/0!	4.26%	3.16%
Depreciation	2.22%	2.48%	#DIV/0!	2.54%	2.59%
Sub-Total	3.43%	4.06%	#DIV/0!	6.80%	5.75%
Grants in Lieu	0.87%	0.70%	#DIV/0!	0.76%	0.85%
Interest	3.27%	2.64%	#DIV/0!	2.83%	3.18%
Preferred Dividends	0.37%	0.30%	#DIV/0!	0.32%	0.36%
Corporate Taxes	2.20%	1.77%	#DIV/0!	1.90%	2.13%
Return	2.54%	2.05%	#DIV/0!	2.20%	2.46%
FIXED CHARGE RATE	**12.68%**	**11.53%**	**#DIV/0!**	**14.80%**	**14.73%**

NSPI **Embedded Cost of Ancillary Services**

TABLE E4-1
Page 2 of 2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES

DETAIL OF COMBUSTION TURBINES

	Burnside	Victoria Junction	Tusket	Tufts Cove 4	Tufts Cove 5	Total Combustion Turbines
Installed Capacity kW's	120000	60000	24000	54000	54000	312000
Gross Plant Cost	$20,187,531	$7,520,949	$5,420,868	$50,038,216	$32,898,580	$116,066,143
Gross Plant Cost/kW	$168.23	$125.35	$225.87	$926.63	$609.23	$372.01
Net Book Value	$5,701,115	$517,383	$1,660,287	$36,964,866	$26,265,982	$71,109,633
Net Book Value/kW	$47.51	$8.62	$69.18	$684.53	$486.41	$227.92
- share of General Property Plant	425,342	38,600	123,869	2,757,833	1,959,623	$5,305,267
- share of Deferred Chgs & W/C	580,840	52,712	169,153	3,766,045	2,676,024	$7,244,774
Total NPV incl. GP & Deferred Chgs.	$6,707,297	$608,695	$1,953,309	$43,488,744	$30,901,628	$52,758,045
OM&G (Direct)	$706,243	$227,611	$298,610	$411,115	$0	$1,643,578
OM&G (Overhead)	($53,276)	($17,170)	($22,526)	($31,013)	$0	($123,984)
Grants in Lieu	$80,731	$7,326	$23,511	$523,443	$371,941	$1,006,951
Depreciation (Direct)	$371,451	$170,726	$298,148	$1,666,273	$1,095,523	$3,602,119
Depr. (General Property)	$46,868	$21,541	$37,619	$210,244	$138,229	$454,501
Interest	$302,902	$27,489	$88,212	$1,963,956	$1,395,520	$3,778,079
Preferred Dividends	$34,153	$3,099	$9,946	$221,442	$157,349	$425,990
Corporate Taxes	$203,247	$18,445	$59,190	$1,317,810	$936,391	$2,535,082
Return	$234,681	$21,298	$68,344	$1,521,622	$1,081,213	$2,927,158
TOTAL	$1,926,999	$480,365	$861,053	$7,804,891	$5,176,166	$16,249,474
OM&G	9.74%	34.57%	14.13%	0.87%	0.00%	2.88%
Depreciation	6.24%	31.59%	17.19%	4.31%	3.99%	7.69%
Sub-Total	15.97%	66.16%	31.32%	5.19%	3.99%	10.57%
Grants in Lieu	1.20%	1.20%	1.20%	1.20%	1.20%	1.91%
Interest	4.52%	4.52%	4.52%	4.52%	4.52%	7.16%
Preferred Dividends	0.51%	0.51%	0.51%	0.51%	0.51%	0.81%
Corporate Taxes	3.03%	3.03%	3.03%	3.03%	3.03%	4.81%
Return	3.50%	3.50%	3.50%	3.50%	3.50%	5.55%
Cost of Capital	12.76%	12.76%	12.76%	12.76%	12.76%	20.23%
FIXED CHARGE RATE	**28.73%**	**78.92%**	**44.08%**	**17.95%**	**16.75%**	**30.80%**

Based on 2011 Data **Embedded Cost of Ancillary Services**

TABLE E4-2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
VOLTAGE CONTROL and REACTIVE SUPPORT SERVICES REVENUE REQUIREMENT

Unit	Generator Nameplate Rating					Generator Net Book Value	Fixed Charge Rate	MVAR Production at System Peak	Allocation to Reactive Power	Allocated Generator Cost	Exciter Cost Ratio	Exciter Cost	Total Gen/Exciter Allocation	Unit Exciter Rating		Ratio of Exciter to Unit Ratings	Exciter Capacity **(Note 4)**	Unit Reactive Capacity Factor	Exciter Energy Consumption Cost
	MVA	MW	MVAR	Peak MW	PRACTICAL MVAR	$				$		$	$	kVA	kW		$		$
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Formula			**(Note 2)**	**(Note 3)**	= sqrt((1*1) - (4*4))				= (5*5)/(1*1)	= 6*9		= 6*11	= 7*(10+12)			= 15/2/1000	= 6*7*16		= 15/1000*8760*18*$59.29/MWh
Lingan 1	177.0	150.0	94.0	166.5	[redacted]	[redacted]	[redacted]	45.53	[redacted]	[redacted]	8%	[redacted]	[redacted]	1430	858	[redacted]	[redacted]	54.54%	$243,027
Lingan 2	177.0	150.0	94.0	163.4	[redacted]	[redacted]	[redacted]	39.57	[redacted]	[redacted]	8%	[redacted]	[redacted]	1430	858	[redacted]	[redacted]	49.10%	$218,805
Lingan 3	177.0	150.0	94.0	166.4	[redacted]	[redacted]	[redacted]	38.43	[redacted]	[redacted]	8%	[redacted]	[redacted]	1430	858	[redacted]	[redacted]	51.34%	$228,780
Lingan 4	177.0	150.0	94.0	168.2	[redacted]	[redacted]	[redacted]	40.48	[redacted]	[redacted]	8%	[redacted]	[redacted]	1430	858	[redacted]	[redacted]	53.57%	$238,735
Tufts Cove 1	117.0	100.0	60.7	87.4	[redacted]	[redacted]	[redacted]	37.38	[redacted]	[redacted]	10%	[redacted]	[redacted]	639	383	[redacted]	[redacted]	53.04%	$105,619
Tufts Cove 2	117.0	100.0	60.7	99.6	[redacted]	[redacted]	[redacted]	34.40	[redacted]	[redacted]	8%	[redacted]	[redacted]	424	255	[redacted]	[redacted]	57.85%	$76,501
Tufts Cove 3	177.0	150.0	94.0	154.1	[redacted]	[redacted]	[redacted]	29.83	[redacted]	[redacted]	8%	[redacted]	[redacted]	1968	1181	[redacted]	[redacted]	38.81%	$238,036
Tufts Cove 4	60.0	54.0	26.2	51.0	[redacted]	[redacted]	[redacted]	6.01	[redacted]	[redacted]	8%	[redacted]	[redacted]	413	248	[redacted]	[redacted]	40.83%	$52,593
Tufts Cove 5	60.0	54.0	26.2	49.8	[redacted]	[redacted]	[redacted]	6.57	[redacted]	[redacted]	8%	[redacted]	[redacted]	413	248	[redacted]	[redacted]	26.17%	$33,706
Trenton 5	177.0	150.0	94.0	163.5	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	1402	841	[redacted]	[redacted]	49.93%	$218,132
Trenton 6	188.0	160.0	98.7	169.8	[redacted]	[redacted]	[redacted]	27.42	[redacted]	[redacted]	8%	[redacted]	[redacted]	1700	1020	[redacted]	[redacted]	65.23%	$345,541
Pt. Tupper 2	177.0	150.0	94.0	160.6	[redacted]	[redacted]	[redacted]	16.61	[redacted]	[redacted]	8%	[redacted]	[redacted]	1186	711	[redacted]	[redacted]	55.98%	$206,834
Pt. Aconi 1	218.0	185.0	115.3	195.5	[redacted]	[redacted]	[redacted]	8.53	[redacted]	[redacted]	8%	[redacted]	[redacted]	1800	1080	[redacted]	[redacted]	25.42%	$142,586
Wreck Cove 1	112.0	100.0	50.4	103.6	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	575	345	[redacted]	[redacted]	0.00%	$0
Wreck Cove 2	112.0	100.0	50.4	104.5	[redacted]	[redacted]	[redacted]	2.91	[redacted]	[redacted]	8%	[redacted]	[redacted]	575	345	[redacted]	[redacted]	0.95%	$1,699
Annapolis Tidal	20.0	17.2	10.2	18.5	[redacted]	[redacted]	[redacted]	0.69	[redacted]	[redacted]	8%	[redacted]	[redacted]	90	54	[redacted]	[redacted]	10.23%	$2,868
Wind (Note 1)	1.0	1.3	0.0	1.0	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]		[redacted]	[redacted]			[redacted]	[redacted]		$0
Other Hydro	181.0	163.0	78.7	163.0	[redacted]	[redacted]	[redacted]	0.0	[redacted]	[redacted]	8%	[redacted]	[redacted]	1358	815	[redacted]	[redacted]	14.81%	$62,647
Burnside 1	35.0	30.0	18.0	31.6	[redacted]	[redacted]	[redacted]	9.17	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$0
Burnside 2	35.0	30.0	18.0	31.3	[redacted]	[redacted]	[redacted]	2.33	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$0
Burnside 3	35.0	30.0	18.0	31.9	[redacted]	[redacted]	[redacted]	4.19	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$0
Burnside 4	35.0	30.0	18.0	0.0	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$0
Victoria Junction 1	35.0	30.0	18.0	31.8	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$0
Victoria Junction 2	35.0	30.0	18.0	31.1	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.04%	$20
Tusket 1	28.0	24.0	14.4	23.8	[redacted]	[redacted]	[redacted]	0.00	[redacted]	[redacted]	8%	[redacted]	[redacted]	169	102	[redacted]	[redacted]	0.00%	$1
TOTALS	2,663.0	2,288.5	1,357.9	2,368.1	1,101.0	$73,332,035		350.1		$12,709,925		$5,908,369	$4,300,991				$90,462		$2,416,131

NOTES:

1. More recent wind generators have var capability, however it is slow acting
2. Nameplate based on MVA and rated Power Factor.
3. Gross generator peak capacity.
4. Value of increased generator capacity required to operate excitor.

Total VAR Requirements (Col. 8 doubled)	700.1
Total Reactive Support Costs - (Col.13+Col.17+Col.19)	$6,807,584
Ratio of VAR Requirements to Sum of Generator VAR Ratings	63.6%
Total Reactive Support Costs	**$4,328,964**

TABLE E4-3

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REGULATION REVENUE REQUIREMENT

Unit	Generator Nameplate Capacity MW	Regulating Capacity MW	Regulating Ramp Rate MW/min	Time on AGC Hours	Regulating Capacity MWh	Ramp Rate Weighting Factor	Weighted Capacity to Regulate MWh	Participation Percentage	Net Book Value $/kW	Fixed Charge Rate	$/kW-yr	Weighted Annual Cost $/kW
Column	1	2	3	4	5	6	7	8	9	10	11	12
Formula		**(Note 1)**	**(Note 2)**	**(Note 3)**	= 2*4	= 3/(Sum of 3)	= 5*6	= 7/(Sum of 7)			= 9*10	= 8*11
Lingan 1	150	25	1.0	747.5	[redacted]							
Lingan 2	150	25	1.0	178.5	[redacted]							
Lingan 3	150	25	1.0	440.0	[redacted]							
Lingan 4	150	25	1.0	146.5	[redacted]							
Tufts Cove 1	100	10	1.0	0.0	[redacted]							
Tufts Cove 2	100	11	1.5	6,534.5	[redacted]							
Tufts Cove 3	150	52	1.5	6,051.5	[redacted]							
Tufts Cove 4	54	30	10.0	5,605.0	[redacted]							
Tufts Cove 5	54	30	10.0	3,927.0	[redacted]							
Trenton 5	150	30	1.0	5.0	[redacted]							
Trenton 6	160	25	2.0	16.5	[redacted]							
Pt. Tupper 2	150	70	1.0	1,173.5	[redacted]							
Pt. Aconi 1	185	0	0.0	1,708.0	[redacted]							
Wreck Cove 1	100	60	15.0	2,772.0	[redacted]							
Wreck Cove 2	100	60	15.0	2,378.0	[redacted]							
Annapolis Tidal	17.2	0	0.0	0.0	[redacted]							
Other Hydro	163	40	20.0	0.0	[redacted]							
Burnside 1	30	25	10.0	60.5	[redacted]							
Burnside 2	30	25	10.0	63.0	[redacted]							
Burnside 3	30	25	10.0	103.5	[redacted]							
Burnside 4	30	25	10.0	0.0	[redacted]							
Victoria Junction 1	30	25	10.0	0.0	[redacted]							
Victoria Junction 2	30	25	10.0	0.0	[redacted]							
Tusket 4	24	10	10.0	0.0	[redacted]							
TOTALS	2287.2	678	152.0	31910.5	1107712.5	100%	54,290	100%				$ 87.49

NOTES:

1. Capacity assigned to Automatic Generation Control.
2. Unit tested capability for ramping control
3. Two year average (SCADA records)

TABLE E4-4

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
LOAD FOLLOWING REVENUE REQUIREMENT

Unit	Type	Net Book Value $/kW	Fixed Charge Rate		Contribution to Load Following Winter morning MW-h	Unit Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6
	Formula			= 1*2		= 4/(Sum of 4)	= 3*5
Lingan 1	Thermal	[redacted]	[redacted]	[redacted]	1,438	[redacted]	[redacted]
Lingan 2	Thermal	[redacted]	[redacted]	[redacted]	1,620	[redacted]	[redacted]
Lingan 3	Thermal	[redacted]	[redacted]	[redacted]	1,167	[redacted]	[redacted]
Lingan 4	Thermal	[redacted]	[redacted]	[redacted]	825	[redacted]	[redacted]
Tufts Cove 1	Thermal	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
Tufts Cove 2	Thermal	[redacted]	[redacted]	[redacted]	750	[redacted]	[redacted]
Tufts Cove 3	Thermal	[redacted]	[redacted]	[redacted]	1,228	[redacted]	[redacted]
Tufts Cove 4	Thermal	[redacted]	[redacted]	[redacted]	1,336	[redacted]	[redacted]
Tufts Cove 5	Thermal	[redacted]	[redacted]	[redacted]	1,006	[redacted]	[redacted]
Trenton 5	Thermal	[redacted]	[redacted]	[redacted]	953	[redacted]	[redacted]
Trenton 6	Thermal	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
Pt. Tupper 2	Thermal	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
Pt. Aconi 1	Thermal	[redacted]	[redacted]	[redacted]	527	[redacted]	[redacted]
Wreck Cove 1	Hydro	[redacted]	[redacted]	[redacted]	2,494	[redacted]	[redacted]
Wreck Cove 2	Hydro	[redacted]	[redacted]	[redacted]	1,981	[redacted]	[redacted]
Annapolis Tidal	Hydro	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
Other Hydro	Hydro	[redacted]	[redacted]	[redacted]	2,327	[redacted]	[redacted]
Burnside 1	LFO	[redacted]	[redacted]	[redacted]	197	[redacted]	[redacted]
Burnside 2	LFO	[redacted]	[redacted]	[redacted]	265	[redacted]	[redacted]
Burnside 3	LFO	[redacted]	[redacted]	[redacted]	146	[redacted]	[redacted]
Burnside 4	LFO	[redacted]	[redacted]	[redacted]	-	[redacted]	[redacted]
TOTALS					18,260	100%	$ 120.77

NOTES:

1. Average one-hour load pickup morning peak November 2010 - March 2011 (SCADA records)

TABLE E4-5

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SPINNING 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Spinning Reserve (10 Minutes) Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**		= Min (1,9*10)		**(Note 4)**	= Max (0,Min(1-7,10))*6*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	[redacted]			901,121	7718	116.8	0.778	1.0	[redacted]	1	-	[redacted]			
Lingan 2	Thermal	150	[redacted]			827,297	7531	109.9	0.732	1.0	[redacted]	1	-	[redacted]			
Lingan 3	Thermal	150	[redacted]			862,142	7861	109.7	0.731	1.0	[redacted]	1	-	[redacted]			
Lingan 4	Thermal	150	[redacted]			902,511	7906	114.2	0.761	1.0	[redacted]	1	-	[redacted]			
Tufts Cove 1	Thermal	100	[redacted]			553,192	7729	71.6	0.716	1.0	[redacted]	0	-	[redacted]			
Tufts Cove 2	Thermal	100	[redacted]			625,712	7937	78.8	0.788	1.5	[redacted]	1	-	[redacted]			
Tufts Cove 3	Thermal	150	[redacted]			782,610	6760	115.8	0.772	1.5	[redacted]	1	-	[redacted]			
Tufts Cove 4	Gas	54	[redacted]			242,298	5909	41.0	0.759	10.0	[redacted]	1	-	[redacted]			
Tufts Cove 5	Gas	54	[redacted]			154,727	4032	38.4	0.711	10.0	[redacted]	1	-	[redacted]			
Trenton 5	Thermal	150	[redacted]			705,371	6010	117.4	0.663	1.0	[redacted]	0	-	[redacted]			
Trenton 6	Thermal	160	[redacted]			1,116,136	7888	141.5	0.753	2.0	[redacted]	1	-	[redacted]			
Pt. Tupper 2	Thermal	150	[redacted]			883,186	6760	130.7	0.738	1.0	[redacted]	1	-	[redacted]			
Pt. Aconi 1	Thermal	185	[redacted]			1,154,978	7674	150.5	0.690	0.0	[redacted]	0	-	[redacted]			
Wreck Cove 1	Hydro	100	[redacted]			183,803	2908	63.2	0.564	15.0	[redacted]	1	-	[redacted]			
Wreck Cove 2	Hydro	100	[redacted]			155,243	2473	62.8	0.561	15.0	[redacted]	1	-	[redacted]			
Annapolis Tidal	Hydro	17.2	[redacted]			28,034	3157	8.9	0.444	0.0	[redacted]	0	-	[redacted]			
Other Hydro	Hydro	163	[redacted]			825,244	8760	94.2	0.000	20.0	[redacted]	0	-	[redacted]			
Burnside 1	Diesel	30	[redacted]			1,535	116	13.3	0.380	10.0	[redacted]	1	-	[redacted]			
Burnside 2	Diesel	30	[redacted]			1,839	122	15.1	0.431	10.0	[redacted]	1	-	[redacted]			
Burnside 3	Diesel	30	[redacted]			1,906	142	13.4	0.383	10.0	[redacted]	1	-	[redacted]			
Burnside 4	Diesel	30	[redacted]			10	29	0.4	0.010	10.0	[redacted]	1	-	[redacted]			
Victoria Junction 1	Diesel	30	[redacted]			148	29	5.2	0.148	10.0	[redacted]	1	-	[redacted]			
Victoria Junction 2	Diesel	30	[redacted]			(45)	26	(1.8)	(0.050)	10.0	[redacted]	1	-	[redacted]			
Tusket 1	Diesel	24	[redacted]			163	20	8.2	0.291	10.0	[redacted]	1	-	[redacted]			
													-				
TOTALS		2287.2	$11,828.62			10,909,163		1,618.9		152.0			0	1,091,499	1,091,499	100%	$ 118.42

NOTES:

1. Average 2010 - 2011
2. Average 2010 - 2011 (SCADA records)
3. Time available to operate, two year average
4. Non-firm exports assigned to units - this no longer applies because as per regulation can no longer include recallable sales/exports.

TABLE E4-6

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 10 Minute Reserve: Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**	= Min (1,9*10)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6 *11 Hyd & Diesel = 1*8*8760 - 5 *11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	[redacted]			901,121	7,718.0	116.8	0.778	1.0	[redacted]	0	-	[redacted]			
Lingan 2	Thermal	150	[redacted]			827,297	7,530.5	109.9	0.732	1.0	[redacted]	0	-	[redacted]			
Lingan 3	Thermal	150	[redacted]			862,142	7,860.5	109.7	0.731	1.0	[redacted]	0	-	[redacted]			
Lingan 4	Thermal	150	[redacted]			902,511	7,905.5	114.2	0.761	1.0	[redacted]	0	-	[redacted]			
Tufts Cove 1	Thermal	100	[redacted]			553,192	7,729.0	71.6	0.716	1.0	[redacted]	0	-	[redacted]			
Tufts Cove 2	Thermal	100	[redacted]			625,712	7,936.5	78.8	0.788	1.5	[redacted]	0	-	[redacted]			
Tufts Cove 3	Thermal	150	[redacted]			782,610	6,759.5	115.8	0.772	1.5	[redacted]	0	-	[redacted]			
Tufts Cove 4	Gas	54	[redacted]			242,298	5,909.0	41.0	0.759	10.0	[redacted]	1	-	[redacted]			
Tufts Cove 5	Gas	54	[redacted]			154,727	4,031.5	38.4	0.711	10.0	[redacted]	1	-	[redacted]			
Trenton 5	Thermal	150	[redacted]			705,371	6,010.0	117.4	0.663	1.0	[redacted]	0	-	[redacted]			
Trenton 6	Thermal	160	[redacted]			1,116,136	7,887.5	141.5	0.753	2.0	[redacted]	0	-	[redacted]			
Pt. Tupper 2	Thermal	150	[redacted]			883,186	6,759.5	130.7	0.738	1.0	[redacted]	0	-	[redacted]			
Pt. Aconi 1	Thermal	185	[redacted]			1,154,978	7,673.5	150.5	0.690	0.0	[redacted]	0	-	[redacted]			
Wreck Cove 1	Hydro	100	[redacted]			183,803	2,907.5	63.2	0.564	15.0	[redacted]	1	-	[redacted]			
Wreck Cove 2	Hydro	100	[redacted]			155,243	2,472.5	62.8	0.561	15.0	[redacted]	1	-	[redacted]			
Annapolis Tidal	Hydro	17.2	[redacted]			28,034	3,156.5	8.9	0.444	0.0	[redacted]	0	-	[redacted]			
Other Hydro	Hydro	163	[redacted]			825,244	8,760.0	94.2	0.000	20.0	[redacted]	0	-	[redacted]			
Burnside 1	Diesel	30	[redacted]			1,535	115.5	13.3	0.380	10.0	[redacted]	1	-	[redacted]			
Burnside 2	Diesel	30	[redacted]			1,839	122.0	15.1	0.431	10.0	[redacted]	1	-	[redacted]			
Burnside 3	Diesel	30	[redacted]			1,906	142.0	13.4	0.383	10.0	[redacted]	1	-	[redacted]			
Burnside 4	Diesel	30	[redacted]			10	28.5	0.4	0.010	10.0	[redacted]	0	-	[redacted]			
Victoria Junction 1	Diesel	30	[redacted]			148	28.5	5.2	0.148	10.0	[redacted]	1	-	[redacted]			
Victoria Junction 2	Diesel	30	[redacted]			(45)	25.5	(1.8)	(0.050)	10.0	[redacted]	0	-	[redacted]			
Tusket 1	Diesel	24	[redacted]			163	20.0	8.2	0.291	10.0	[redacted]	1	-	[redacted]			
TOTALS		2287.2	$11,828.62			10,909,163		1,618.9		152.0			0	1,194,528	1,194,528	100%	$ 56.41

NOTES:

1. Average 2010 - 2011
2. Average 2010 - 2011 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units (2011)

Based on 2011 Data **Embedded Cost of Ancillary Services**

TABLE E4-7

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 30 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Installed Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 30 Minute Reserve: Response 10 - 30 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**	= Min (1,9*20)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6*11 Hyd & Diesel = ((1*8*8760)- 5)*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	[redacted]	[redacted]	[redacted]	901,121	7,718.0	116.8	0.778	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Lingan 2	Thermal	150	[redacted]	[redacted]	[redacted]	827,297	7,530.5	109.9	0.732	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Lingan 3	Thermal	150	[redacted]	[redacted]	[redacted]	862,142	7,860.5	109.7	0.731	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Lingan 4	Thermal	150	[redacted]	[redacted]	[redacted]	902,511	7,905.5	114.2	0.761	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Tufts Cove 1	Thermal	100	[redacted]	[redacted]	[redacted]	553,192	7,729.0	71.6	0.716	1.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Tufts Cove 2	Thermal	100	[redacted]	[redacted]	[redacted]	625,712	7,936.5	78.8	0.788	1.5	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Tufts Cove 3	Thermal	150	[redacted]	[redacted]	[redacted]	782,610	6,759.5	115.8	0.772	1.5	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Tufts Cove 4	Gas	54	[redacted]	[redacted]	[redacted]	242,298	5,909.0	41.0	0.759	10.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Tufts Cove 5	Gas	54	[redacted]	[redacted]	[redacted]	154,727	4,031.5	38.4	0.711	10.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Trenton 5	Thermal	150	[redacted]	[redacted]	[redacted]	705,371	6,010.0	117.4	0.663	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Trenton 6	Thermal	160	[redacted]	[redacted]	[redacted]	1,116,136	7,887.5	141.5	0.753	2.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Pt. Tupper 2	Thermal	150	[redacted]	[redacted]	[redacted]	883,186	6,759.5	130.7	0.738	1.0	[redacted]	1	-	[redacted]	[redacted]	[redacted]	[redacted]
Pt. Aconi 1	Thermal	185	[redacted]	[redacted]	[redacted]	1,154,978	7,673.5	150.5	0.690	0.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Wreck Cove 1	Hydro	100	[redacted]	[redacted]	[redacted]	183,803	2,907.5	63.2	0.564	15.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Wreck Cove 2	Hydro	100	[redacted]	[redacted]	[redacted]	155,243	2,472.5	62.8	0.561	15.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Annapolis Tidal	Hydro	17.2	[redacted]	[redacted]	[redacted]	28,034	3,156.5	8.9	0.444	0.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Other Hydro	Hydro	163	[redacted]	[redacted]	[redacted]	825,244	8,760.0	94.2	0.000	20.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Burnside 1	Diesel	30	[redacted]	[redacted]	[redacted]	1,535	115.5	13.3	0.380	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Burnside 2	Diesel	30	[redacted]	[redacted]	[redacted]	1,839	122.0	15.1	0.431	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Burnside 3	Diesel	30	[redacted]	[redacted]	[redacted]	1,906	142.0	13.4	0.383	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Burnside 4	Diesel	30	[redacted]	[redacted]	[redacted]	10	28.5	0.4	0.010	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Victoria Junction 1	Diesel	30	[redacted]	[redacted]	[redacted]	148	28.5	5.2	0.148	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Victoria Junction 2	Diesel	30	[redacted]	[redacted]	[redacted]	(45)	25.5	(1.8)	(0.050)	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
Tusket 1	Diesel	24	[redacted]	[redacted]	[redacted]	163	20.0	8.2	0.291	10.0	[redacted]	0	-	[redacted]	[redacted]	[redacted]	[redacted]
TOTALS		2287.2	$11,828.62			10,909,163		1,618.9		152.0			0	1,527,578	1,527,578	100.00%	$ 131.95

NOTES:

1. Average 2010 - 2011
2. Average 2010 - 2011 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units (2011)

Attachment H: Exit Fees

Open Access Transmission Tariff

ATTTACHMENT H

Methodology for Recovery of Embedded Cost Obligation

Objective

Sections 26.0 and 34.5 of the OATT provide for the recovery of stranded costs when wholesale customers use the OATT as a mechanism for exiting bundled service supply. The purpose of this document is to describe the methodology used by the Transmission Provider to determine those stranded cost obligations.

NS Power's Proposed Method for the Determination of Embedded Cost Obligation

Embedded Cost Obligation = FAM Obligation + Forgone Future Revenue

> FAM Obligation = FAM AA Amount + FAM BA Amount + current year fuel cost imbalance
>
> Forgone Future Revenue = (Base Cost Rate Revenue Estimate – Competitive Market Value) * Length of obligation of 5 years
>
> > Base Cost Rate Revenue Estimate = Bundled Service Revenue – OATT Revenue – BUTU revenue (if applicable)
> >
> > Competitive Market Value = Higher of avoided costs or market price based revenue

When requested, and provided with a detailed scenario, NS Power will provide an estimate of expected embedded cost obligations, in order for customers who are considering an alternative supply to evaluate options. If notice of intent to exit is subsequently received by NS Power, the estimate will be revised to reflect current conditions and an actual cost recovery fee will be determined.

The specific terms and conditions for payment of the embedded cost recovery fee will be as approved by the UARB.

Energy+Environmental Economics
101 Montgomery Street | Suite 1600 | San Francisco, CA 94104 | 415.391.5100 | www.ethree.com

May 2, 2012

Nova Scotia Power Inc.
1223 Lower Water St.
Halifax, Nova Scotia
B3J 3S8
Attn: Ms. Nicole Godbout

Dear Ms. Godbout:

Re: Nova Scotia Power Incorporated ("NS Power") Open Access Transmission Tariff ("OATT") Update, filed with the Nova Scotia Utility and Review Board (the "Board") May, 2012

Overview

Energy and Environmental Economics ("E3") was retained to advise and support NS Power in the utility's preparation of the referenced Application (the "Application"). In particular, E3 was asked to:

1. Advise on NS Power's proposed rates, from the perspectives of both sound utility rate-making and, more specifically, the Application's conformity with FERC pricing principles; and

2. Advise on NS Power's Embedded Cost Recovery Mechanism, as described in the Application.

E3's retainer did not include review or verification of NS Power's underlying cost of service data or verification of the detailed calculation of NS Power's Embedded Cost Recovery Mechanism. The results of E3's review are described below.

E3 Qualifications

As you are aware, E3 has provided expert advice on FERC-related matters for more than 20 years. We have advised Canadian utilities on transmission pricing, policy, and strategy issues since the mid-1990s. E3 provided transmission tariff design expertise for the initial FERC-compliant transmission tariffs in British Columbia, Ontario, and Quebec. We have supported all three of those jurisdictions in evaluating and, where appropriate, implementing updates to those tariffs in line with emerging FERC orders and evolving industry conditions.

Rates and Pricing

E3 was asked to provide a review of the pricing changes proposed in the Application. E3 reviewed the pricing provisions of the Application for consistency with standard rate-making practices. E3 also provided a high-level review of the work-sheets prepared by NS Power to verify consistency with the rates being sought. In respect of this review, E3 believes that the Application is consistent with sound rate-making principles and the rates appear to have been appropriately derived.

Embedded Cost Recovery Mechanism

E3 was asked to review and advise on implementation of an exit fee (Embedded Cost Recovery Mechanism, or "ECRM") applicable to NS Power customers departing utility service for market purchases.

E3 has reviewed NS Power's proposed ECRM and believes that it is generally reasonable: (1) in light of changes to the NS Power operating environment since 2005; (2) given the nature of NS Power investment patterns for, and service obligations to, potentially departing customers; and (3) because of its consistency with industry practice and FERC's direction.

Conclusion

E3 has reviewed the Application and believes that it provides a balanced and sensible update to NS Power's OATT. We believe, in particular, that:

1. The rate changes proposed by NS Power are consistent with NS Power's 2005 rate-making practices and standard rate-making practices, and appear to have been correctly derived;

2. It is appropriate for NS Power to act now to introduce an exit fee (ECRM) mechanism, since such action provides both protection to existing NS Power customers and cost clarity to eligible customers considering leaving NS Power for market purchases; and
3. The general form of the ECRM proposed by NS Power is in line with FERC practices.

We understand that NS Power may decide to file this correspondence in support of its Application.

Sincerely,

Ren Orans
Managing Partner

Cameron Lusztig
Managing Director, Canada

2013 REVENUE INCREASE ANALYSIS

1	Rate Classes	2013 Sales (GWh's)	2013 Revenue at current rates before cost adjustment clauses	2012 FAM AA	2012 FAM BA	Revenue at current rates including 2012 AA/BA	Proposed Revenues 2013 Before Riders			AA Component				BA Component				2013 Revenue reflective of all FAM components		
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	ATL																			
5	Residential	4,273.2	$588,717,083	$15,729,855	$13,940,592	$618,387,531	$656,556,743	$67,839,659	11.0%	$15,729,855	$0	($15,729,855)	-2.5%	$13,940,592	$11,528,175	($2,412,417)	-0.4%	$668,084,918	$49,697,387	8.0%
6																				
7	Small General	231.3	$31,454,192	$836,570	$784,960	$33,075,722	$35,078,754	$3,624,562	11.0%	$836,570	$0	($836,570)	-2.5%	$784,960	$663,040	($121,920)	-0.4%	$35,741,794	$2,666,072	8.1%
8	General Demand	2,435.3	$275,984,112	$9,236,101	$9,197,989	$294,418,202	$307,786,600	$31,802,488	10.8%	$9,236,101	$0	($9,236,101)	-3.1%	$9,197,989	$7,640,244	($1,557,745)	-0.5%	$315,426,844	$21,008,642	7.1%
9	Large General	396.3	$37,795,519	$1,348,850	$1,443,410	$40,587,779	$42,150,811	$4,355,293	10.7%	$1,348,850	$0	($1,348,850)	-3.3%	$1,443,410	$1,341,147	($102,262)	-0.3%	$43,491,959	$2,904,180	7.2%
10	Total Commercial	3,062.9	$345,233,823	$11,421,520	$11,426,359	$368,081,702	$385,016,166	$39,782,343	10.8%	$11,421,520	$0	($11,421,520)	-3.1%	$11,426,359	$9,644,431	($1,781,928)	-0.5%	$394,660,597	$26,578,895	7.2%
11																		$0		
12	Small Industrial	258.2	$28,459,582	$834,757	$876,178	$30,170,517	$31,739,066	$3,279,484	10.9%	$834,757	$0	($834,757)	-2.8%	$876,178	$827,567	($48,612)	-0.2%	$32,566,633	$2,396,116	7.9%
13	Medium Industrial	498.8	$47,959,530	$1,569,891	$1,659,488	$51,188,909	$53,486,053	$5,526,522	10.8%	$1,569,891	$0	($1,569,891)	-3.1%	$1,659,488	$1,564,646	($94,842)	-0.2%	$55,050,699	$3,861,790	7.5%
14	*Large Industrial - Firm*	*224.8*	*$18,598,529*	*$721,583*	*$796,880*	*$20,116,992*	*$20,592,922*	*$1,994,393*	*9.9%*	*$721,583*	*$0*	*($721,583)*	*-3.6%*	*$796,880*	*$747,144*	*($49,736)*	*-0.2%*	*$21,340,066*	*$1,223,074*	*6.1%*
15	*Large Industrial - Interruptible*	*696.6*	*$55,222,023*	*$2,153,715*	*$2,378,457*	*$59,754,194*	*$61,734,196*	*$6,512,174*	*10.9%*	*$2,153,715*	*$0*	*($2,153,715)*	*-3.6%*	*$2,378,457*	*$2,314,922*	*($63,535)*	*-0.1%*	*$64,049,118*	*$4,294,924*	*7.2%*
16	Total Large Industrial	921.4	$73,820,552	$2,875,298	$3,175,337	$79,871,186	$82,327,118	$8,506,567	10.7%	$2,875,298	$0	($2,875,298)	-3.6%	$3,175,337	$3,062,066	($113,271)	-0.1%	$85,389,184	$5,517,998	6.9%
17	ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	Total Industrial	1,678.4	$150,239,663	$5,279,946	$5,711,003	$161,230,612	$167,552,237	$17,312,573	10.7%	$5,279,946	$0	($5,279,946)	-3.3%	$5,711,003	$5,454,279	($256,724)	-0.2%	$173,006,515	$11,775,903	7.3%
19																				
20	Municipal	192.6	$18,286,843	$665,963	$716,472	$19,669,277	$20,394,092	$2,107,249	10.7%	$665,963	$0	($665,963)	-3.4%	$716,472	$525,575	($190,896)	-1.0%	$20,919,667	$1,250,390	6.4%
21	Unmetered	104.4	$22,338,108	$365,351	$422,941	$23,126,401	$24,633,382	$2,295,274	9.9%	$365,351	$0	($365,351)	-1.6%	$422,941	$403,570	($19,371)	-0.1%	$25,036,953	$1,910,552	8.3%
22	Total Other	297.0	$40,624,951	$1,031,314	$1,139,413	$42,795,678	$45,027,474	$4,402,523	10.3%	$1,031,314	$0	($1,031,314)	-2.4%	$1,139,413	$929,146	($210,267)	-0.5%	$45,956,620	$3,160,942	7.4%
23																				
24	Total ATL Classes	9,311.5	$1,124,815,521	$33,462,635	$32,217,367	$1,190,495,523	$1,254,152,619	$129,337,098	10.9%	$33,462,635	$0	($33,462,635)	-2.8%	$32,217,367	$27,556,031	($4,661,336)	-0.4%	$1,281,708,650	$91,213,127	7.7%
25																				
26	BTL (Electric)																			
27	GRLF	18.8	$1,094,660	$0	$0	$1,094,660	$1,094,660	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,094,660	$0	0.0%
28	Mersey Additional Energy	178.9	$10,282,532	$0	$419,451	$10,701,983	$10,282,532	$0	0.0%	$0	$0	$0	0.0%	$419,451	$290,429	($129,022)	-1.2%	$10,572,961	($129,022)	-1.2%
	LRT	322.1	$21,183,202	$879,406	$1,219,578	$23,282,186	$21,183,202	$0	0.0%	$879,406	$0	($879,406)	-3.8%	$1,219,578	$1,330,573	$110,995	0.5%	$22,513,775	($768,411)	-3.3%
29	Bowater Mersey	189.0	$9,934,827	$0	$0	$9,934,827	$9,934,827	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$9,934,827	$0	0.0%
30	Total BTL (Electric) Classes	708.8	$42,495,221	$879,406	$1,639,029	$45,013,656	$42,495,221	$0	0.0%	$879,406	$0	($879,406)	-2.0%	$1,639,029	$1,621,002	($18,027)	0.0%	$44,116,223	($897,433)	-2.0%
31																				
32	LED SL Capital Costs		$1,565,170	$0	$0	$1,565,170	$1,962,839	$397,669	25.4%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,962,839	$397,669	25.4%
33																				
34																				
35	In Province Total	10,020.3	$1,168,875,912	$34,342,042	$33,856,395	$1,237,074,349	$1,298,610,679	$129,734,767	10.5%	$34,342,042	$0	($34,342,042)	-2.8%	$33,856,395	$29,177,033	($4,679,363)	-0.4%	$1,327,787,711	$90,713,363	7.3%
36																				
37	Export	28.9	$1,806,823	$0	$0	$1,806,823	$1,806,823	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,806,823	$0	0.0%
38																				
39	Total Electric Sales	10,049.2	$1,170,682,735	$34,342,042	$33,856,395	$1,238,881,172	$1,300,417,502	$129,734,767	10.5%	$34,342,042	$0	($34,342,042)	-2.8%	$33,856,395	$29,177,033	($4,679,363)	-0.4%	$1,329,594,534	$90,713,363	7.3%
40																				
41	Misc Revenue	701.7	$21,959,249	$0	$0	$21,959,249	$22,582,498	$623,250	2.8%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$22,582,498	$623,250	2.8%
42																				
43	Grand Total	10,750.9	$1,192,641,983	$34,342,042	$33,856,395	$1,260,840,421	$1,323,000,000	$130,358,017	10.3%	$34,342,042	$0	($34,342,042)	-2.7%	$33,856,395	$29,177,033	($4,679,363)	-0.4%	$1,352,177,033	$91,336,612	7.2%
44																				
45																				
46	* The 2012 FAM AA/BA Figures have been adjusted to reflect the 2013 LRT Load																			

2014 REVENUE INCREASE ANALYSIS

							Proposed Revenues 2014 Before Riders			AA Component				BA Component				2014 Revenue reflective of all FAM components		
1	Rate Classes	2014 Sales (GWh's)	2014 Revenue at current rates before cost adjustment clauses	2013 FAM AA	2013 FAM BA	Revenue at current rates including 2013 BA														
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	**ATL**																			
5	**Residential**	**4,257.2**	**$654,440,059**	**$0**	**$11,528,175**	**$665,968,234**	**$689,767,669**	**$35,327,610**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$11,528,175**	**$0**	**($11,528,175)**	**-1.7%**	**$689,767,669**	**$23,799,435**	**3.6%**
6																				
7	Small General	229.4	$34,808,029	$0	$663,040	$35,471,069	$36,687,017	$1,878,987	5.3%	$0	$0	$0	0.0%	$663,040	$0	($663,040)	-1.9%	$36,687,017	$1,215,947	3.4%
8	General Demand	2,433.0	$305,474,364	$0	$7,640,244	$313,114,608	$321,964,307	$16,489,943	5.3%	$0	$0	$0	0.0%	$7,640,244	$0	($7,640,244)	-2.4%	$321,964,307	$8,849,699	2.8%
9	Large General	387.0	$41,426,211	$0	$1,341,147	$42,767,359	$43,662,457	$2,236,246	5.2%	$0	$0	$0	0.0%	$1,341,147	$0	($1,341,147)	-3.1%	$43,662,457	$895,099	2.1%
10	**Total Commercial**	**3,049.4**	**$381,708,605**	**$0**	**$9,644,431**	**$391,353,036**	**$402,313,781**	**$20,605,176**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$9,644,431**	**$0**	**($9,644,431)**	**-2.5%**	**$402,313,781**	**$10,960,745**	**2.8%**
11																				
12	Small Industrial	260.3	$31,779,026	$0	$827,567	$32,606,593	$33,494,503	$1,715,477	5.3%	$0	$0	$0	0.0%	$827,567	$0	($827,567)	-2.5%	$33,494,503	$887,911	2.7%
13	Medium Industrial	512.8	$54,358,393	$0	$1,564,646	$55,923,039	$57,292,737	$2,934,344	5.2%	$0	$0	$0	0.0%	$1,564,646	$0	($1,564,646)	-2.8%	$57,292,737	$1,369,697	2.4%
14	*Large Industrial - Firm*	*228.7*	*$20,861,588*	*$0*	*$747,144*	*$21,608,732*	*$21,922,990*	*$1,061,402*	*4.9%*	*$0*	*$0*	*$0*	*0.0%*	*$747,144*	*$0*	*($747,144)*	*-3.5%*	*$21,922,990*	*$314,258*	*1.5%*
15	*Large Industrial - Interruptible*	*693.1*	*$61,510,900*	*$0*	*$2,314,922*	*$63,825,822*	*$64,921,418*	*$3,410,517*	*5.3%*	*$0*	*$0*	*$0*	*0.0%*	*$2,314,922*	*$0*	*($2,314,922)*	*-3.6%*	*$64,921,418*	*$1,095,596*	*1.7%*
16	Total Large Industrial	921.8	$82,372,488	$0	$3,062,066	$85,434,554	$86,844,408	$4,471,919	5.2%	$0	$0	$0	0.0%	$3,062,066	$0	($3,062,066)	-3.6%	$86,844,408	$1,409,853	1.7%
17	ELI_2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	**Total Industrial**	**1,694.8**	**$168,509,908**	**$0**	**$5,454,279**	**$173,964,186**	**$177,631,648**	**$9,121,740**	**5.2%**	**$0**	**$0**	**$0**	**0.0%**	**$5,454,279**	**$0**	**($5,454,279)**	**-3.1%**	**$177,631,648**	**$3,667,462**	**2.1%**
19																				
20	Municipal	191.7	$20,382,352	$0	$525,575	$20,907,927	$21,482,620	$1,100,269	5.3%	$0	$0	$0	0.0%	$525,575	$0	($525,575)	-2.5%	$21,482,620	$574,693	2.7%
21	Unmetered	97.8	$23,080,853	$0	$403,570	$23,484,424	$23,989,269	$908,415	3.9%	$0	$0	$0	0.0%	$403,570	$0	($403,570)	-1.7%	$23,989,269	$504,845	2.1%
22	**Total Other**	**289.5**	**$43,463,205**	**$0**	**$929,146**	**$44,392,351**	**$45,471,889**	**$2,008,684**	**4.5%**	**$0**	**$0**	**$0**	**0.0%**	**$929,146**	**$0**	**($929,146)**	**-2.1%**	**$45,471,889**	**$1,079,538**	**2.4%**
23																				
24	**Total ATL Classes**	**9,291.0**	**$1,248,121,777**	**$0**	**$27,556,031**	**$1,275,677,807**	**$1,315,184,988**	**$67,063,211**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$27,556,031**	**$0**	**($27,556,031)**	**-2.2%**	**$1,315,184,988**	**$39,507,180**	**3.1%**
25																				
26	**BTL (Electric)**																			
27	GRLF	18.8	$1,071,642	$0	$0	$1,071,642	$1,071,642	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,071,642	$0	0.0%
28	Mersey Additional Energy	178.9	$10,241,381	$0	$290,429	$10,531,810	$10,241,381	$0	0.0%	$0	$0	$0	0.0%	$290,429	$0	($290,429)	-2.8%	$10,241,381	($290,429)	-2.8%
	LRT	322.1	$21,856,349	$0	$1,330,573	$23,186,922	$21,856,349	$0	0.0%	$0	$0	$0	0.0%	$1,330,573	$0	($1,330,573)	-5.7%	$21,856,349	($1,330,573)	-5.7%
29	Bowater Mersey	189.0	$9,782,311	$0	$0	$9,782,311	$9,782,311	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$9,782,311	$0	0.0%
30	**Total BTL (Electric) Classes**	**708.8**	**$42,951,683**	**$0**	**$1,621,002**	**$44,572,685**	**$42,951,683**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$1,621,002**	**$0**	**($1,621,002)**	**-3.6%**	**$42,951,683**	**($1,621,002)**	**-3.6%**
31																				
32	LED SL Capital Costs		$4,259,866	$0	$0	$4,259,866	$4,340,815	$80,949	1.9%	$0	**$0**	**$0**	**N/A**	$0	**$0**	**$0**	**N/A**	$4,340,815	$80,949	1.9%
33																				
34																				
35	**In Province Total**	**9,999.8**	**$1,295,333,326**	**$0**	**$29,177,033**	**$1,324,510,358**	**$1,362,477,486**	**$67,144,160**	**5.1%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.2%**	**$1,362,477,486**	**$37,967,128**	**2.9%**
36																				
37	Export	29.5	$1,943,419	$0	$0	$1,943,419	$1,943,419	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,943,419	$0	0.0%
38																				
39	**Total Electric Sales**	**10,029.3**	**$1,297,276,745**	**$0**	**$29,177,033**	**$1,326,453,777**	**$1,364,420,905**	**$67,144,160**	**5.1%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.2%**	**$1,364,420,905**	**$37,967,128**	**2.9%**
40																				
41	Misc Revenue	710.6	$23,145,757	$0	$0	$23,145,757	$23,479,095	$333,338	1.4%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$23,479,095	$333,338	1.4%
42																				
43	**Grand Total**	**10,739.9**	**$1,320,422,502**	**$0**	**$29,177,033**	**$1,349,599,534**	**$1,387,900,000**	**$67,477,498**	**5.0%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.2%**	**$1,387,900,000**	**$38,300,466**	**2.8%**
44																				
45																				
46	* The figures for LRT have been adjusted to reflect the correct load																			

1 ALLOCATION OF REVENUE RESPONSIBILITIES TO ABOVE THE LINE CLASSES AND MISCELLANEOUS REVENUES

The following sections discuss the process used by NS Power in the allocation of revenue responsibilities among Above the Line (ATL) classes and Miscellaneous Services for 2013 and 2014. NS Power has followed a process intended to fairly and equitably recover costs from all classes. Revenue from each class is designed to recover 95-105 percent of costs. Classes with the lowest existing revenue to cost ratios require higher revenue increases to bring them closer to other class Revenue to Cost (R/C) ratios.

1.1 Test Year 2013

The 2013 revenue requirement from ATL classes and Miscellaneous Services is $1,276.7 million. This is calculated by subtracting the following revenues from the total revenue requirement of $1,323.0 million:

- $42.5 million in revenue forecast from BTL classes;
- $2.0 million from LED capital costs;
- $1.8 million in revenue expected to be received from export sales

With the revenue at current rates from ATL classes and Miscellaneous Services forecast at $1,146.8 million, the required increase to these two categories is $130.0 million. The revenue allocation process apportions $129.4 million of that amount to ATL classes and $0.6 million to Miscellaneous Services. The $130.0 million shortfall requires an average increase in ATL revenue of 11.5 percent.

1.2 Revenue to Cost Ratios and Proposed Changes to ATL classes and Miscellaneous Services

Figure 1-1 compares projected costs to expected 2013 revenues at present rates (that is, ATL classes, Miscellaneous Services and LED Street Light Capital-related Costs). This comparison presents a revenue shortfall of $130.4 million between the revenue collected under present rates and the revenue required in 2013.

Figure 1-1

	R/C Ratio	% Revenue Increase	Proposed Revenue ($)
ABOVE-THE-LINE CLASSES			
Residential	**88.7%**	**0.0%**	**$588.7**
Commercial			
Small General	93.7%	0.0%	$31.5
General Demand	92.8%	0.0%	$276.0
Large General	88.0%	0.0%	$37.8
Total Commercial	92.3%	**0.0%**	**$345.2**
Industrial			
Small Industrial	91.9%	0.0%	$28.5
Medium Industrial	88.2%	0.0%	$48.0
Large Industrial	85.6%	0.0%	$73.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**87.6%**	**0.0%**	**$150.2**
Other			
Municipal	87.3%	0.0%	$18.3
Unmetered	90.6%	0.0%	$22.3
Total Other	**89.1%**	**0.0%**	**$40.6**
Total Above-the-line classes	**89.6%**	**0.0%**	**$1,124.8**
BTL (Electric Services)		**0.0%**	**$42.5**
Exports		**0.0%**	**$1.8**
LED SL Capital-related Costs		**N/A**	**$1.6**
Miscellaneous		**0.0%**	**$22.0**
Total Revenue		**0.0%**	**$1,192.6**
Revenue Requirement			**$1,323.0**
Revenue Shortfall/Surplus			**-$130.4**

Figure 1-2 compares projected costs to expected 2013 revenues from ATL classes and Miscellaneous Services priced at present rates and those of LED Street Light Capital-related priced at proposed rates. This comparison now presents a revenue shortfall of $130.0 million.

Figure 1-2

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**88.7%**	**0.0%**	**$588.7**
Commercial			
Small General	93.7%	0.0%	$31.5
General Demand	92.8%	0.0%	$276.0
Large General	88.0%	0.0%	$37.8
Total Commercial	**92.3%**	**0.0%**	**$345.2**
Industrial			
Small Industrial	91.9%	0.0%	$28.5
Medium Industrial	88.2%	0.0%	$48.0
Large Industrial	85.6%	0.0%	$73.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**87.6%**	**0.0%**	**$150.2**
Other			
Municipal	87.3%	0.0%	$18.3
Unmetered	90.6%	0.0%	$22.3
Total Other	**89.1%**	**0.0%**	**$40.6**
Total Above-the-line classes	**89.6%**	**0.0%**	**$1,124.8**
BTL (Electric Services)		**0.0%**	**$42.5**
Exports		**0.0%**	**$1.8**
LED SL Capital-related Costs		**N/A**	**$2.0**
Miscellaneous		**0.0%**	**$22.0**
Total Revenue		**0.0%**	**$1,193.0**
Revenue Requirement			**$1,323.0**
Revenue Shortfall/Surplus			**-$130.0**

Figure 1-3 presents revenue to cost ratios for ATL classes after Unmetered Class revenue has been set at cost and the revenues of all other ATL classes and selected miscellaneous services have been increased across-the-board to balance with costs. This step yields R/C ratios for all rate classes falling within the prescribed 95 – 105 percent band bringing the revenue allocation process to an end. The resulting increase to all rate classes other than the Unmetered Class is 11.5 percent.

Figure 1-3

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.0%**	**11.5%**	**$656.6**
Commercial			
Small General	104.6%	11.5%	$35.1
General Demand	103.5%	11.5%	$307.8
Large General	98.2%	11.5%	$42.2
Total Commercial	**103.0%**	**11.5%**	**$385.0**
Industrial			
Small Industrial	102.5%	11.5%	$31.7
Medium Industrial	98.4%	11.5%	$53.5
Large Industrial	95.5%	11.5%	$82.3
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.7%**	**11.5%**	**$167.6**
Other			
Municipal	97.4%	11.5%	$20.4
Unmetered	100.0%	10.3%	$24.6
Total Other	**98.8%**	**10.8%**	**$45.0**
Total Above-the-line classes	**100.0%**	**11.5%**	**$1,254.2**
BTL (Electric Services)		**0.0%**	**$42.5**
Exports		**0.0%**	**$1.8**
LED SL Capital-related Costs		**N/A**	**$2.0**
Miscellaneous		**2.8%**	**$22.6**
Total Revenue		**10.9%**	**$1,323.0**
Revenue Requirement			**$1,323.0**
Revenue Shortfall/Surplus			**$0.0**

1.3 Test Year 2014

The 2014 revenue requirement from ATL classes and Miscellaneous Services is $1,338.7 million. This is calculated by subtracting the following revenues from the total revenue requirement of $1,387.9 million:

- $43.0 million in revenue forecast from BTL classes;
- $4.3 million from LED capital costs;
- $1.9 million in revenue expected to be received from export sales.

With the revenue forecast of $1,271.2 million from ATL classes and Miscellaneous Services, priced at the rates proposed for 2013, the required increase to these two categories for 2014 is $67.5 million. The revenue allocation process apportions $67.1 million of that amount to ATL classes and $0.3 million to Miscellaneous Services. The $67.1 million shortfall requires an average increase in ATL revenue of 5.4 percent.

Figure 1-4 compares projected costs to expected 2014 revenues at present rates (that is, ATL classes, Miscellaneous Services and LED Street Light Capital-related Revenues). This comparison presents a revenue shortfall of $67.5 million between the revenue collected under present rates and the revenue required in 2014.

Figure 1-4

	R/C Ratio	% Revenue Increase	Proposed Revenue ($)
ABOVE-THE-LINE CLASSES			
Residential	**94.3%**	**0.0%**	**$654.4**
Commercial			
Small General	99.0%	0.0%	$34.8
General Demand	97.5%	0.0%	$305.5
Large General	93.6%	0.0%	$41.4
Total Commercial	97.2%	**0.0%**	**$381.7**
Industrial			
Small Industrial	96.8%	0.0%	$31.8
Medium Industrial	92.3%	0.0%	$54.4
Large Industrial	90.1%	0.0%	$82.4
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**92.0%**	**0.0%**	**$168.5**
Other			
Municipal	92.9%	0.0%	$20.4
Unmetered	96.2%	0.0%	$23.1
Total Other	**94.6%**	**0.0%**	**$43.5**
Total Above-the-line classes	**94.9%**	**0.0%**	**$1,248.1**
BTL (Electric Services)		**0.0%**	**$43.0**
Exports		**0.0%**	**$1.9**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**0.0%**	**$23.1**
Total Revenue		**0.0%**	**$1,320.4**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			**-$67.5**

Figure 1-5 compares projected costs to expected 2014 revenues from ATL classes and Miscellaneous Services priced at the rates proposed for 2013 and those for LED Street Light Capital priced at the rates proposed for 2014. This comparison presents a revenue shortfall of $67.4 million.

Figure 1-5

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**94.3%**	**0.0%**	**$654.4**
Commercial			
Small General	99.0%	0.0%	$34.8
General Demand	97.5%	0.0%	$305.5
Large General	93.6%	0.0%	$41.4
Total Commercial	**97.2%**	**0.0%**	**$381.7**
Industrial			
Small Industrial	96.8%	0.0%	$31.8
Medium Industrial	92.3%	0.0%	$54.4
Large Industrial	90.1%	0.0%	$82.4
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**92.0%**	**0.0%**	**$168.5**
Other			
Municipal	92.9%	0.0%	$20.4
Unmetered	96.2%	0.0%	$23.1
Total Other	**94.6%**	**0.0%**	**$43.5**
Total Above-the-line classes	**94.9%**	**0.0%**	**$1,248.1**
BTL (Electric Services)		**0.0%**	**$43.0**
Exports		**0.0%**	**$1.9**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**0.0%**	**$23.1**
Total Revenue		**0.0%**	**$1,320.5**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			**-$67.4**

Figure 1-6 presents revenue to cost ratios for ATL classes after Unmetered Class revenue has been set at cost and the revenues of all other ATL classes and selected Miscellaneous Services have been increased across-the-board to balance with costs. This results in a 5.4 percent average increase to all the ATL classes other than the Unmetered Class. At this stage of rate development, the Large Industrial class has a revenue to cost ratio outside of the of 95-105 percent range.

Figure 1-6

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.4%**	**5.4%**	**$689.8**
Commercial			
Small General	104.4%	5.4%	$36.7
General Demand	102.8%	5.4%	$322.0
Large General	98.7%	5.4%	$43.7
Total Commercial	**102.5%**	**5.4%**	**$402.3**
Industrial			
Small Industrial	102.0%	5.4%	$33.5
Medium Industrial	97.3%	5.4%	$57.3
Large Industrial	95.0%	5.4%	$86.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.0%**	**5.4%**	**$177.6**
Other			
Municipal	98.0%	5.4%	$21.5
Unmetered	100.0%	3.9%	$24.0
Total Other	**99.0%**	**4.6%**	**$45.5**
Total Above-the-line classes	**100.0%**	**5.4%**	**$1,315.2**
BTL (Electric Services)		**0.0%**	**$43.0**
Exports		**0.0%**	**$1.9**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**1.4%**	**$23.5**
Total Revenue		**5.1%**	**$1,387.9**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			**$0.0**

Note: The Large Industrial R/C ratio above is 94.95%.

As Figure 1-7 illustrates, increasing the R/C ratio of the Large Industrial class to the minimum 95 percent results in a revenue surplus of $0.02 million.

Figure 1-7

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.4%**	**5.4%**	**$689.8**
Commercial			
Small General	104.4%	5.4%	$36.7
General Demand	102.8%	5.4%	$322.0
Large General	98.7%	5.4%	$43.7
Total Commercial	**102.5%**	**5.4%**	**$402.3**
Industrial			
Small Industrial	102.0%	5.4%	$33.5
Medium Industrial	97.3%	5.4%	$57.3
Large Industrial	95.0%	5.4%	$86.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.0%**	**5.4%**	**$177.6**
Other			
Municipal	98.0%	5.4%	$21.5
Unmetered	100.0%	3.9%	$24.0
Total Other	**99.0%**	**4.6%**	**$45.5**
Total Above-the-line classes	**100.0%**	**5.4%**	**$1,315.2**
BTL (Electric Services)		0.0%	**$43.0**
Exports		0.0%	**$1.9**
LED SL Capital-related Costs		N/A	**$4.3**
Miscellaneous		**1.4%**	**$23.5**
Total Revenue		**5.1%**	**$1,387.9**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			**$0.02**

Figure 1-8 shows the result of allocating the $0.02 million surplus across all classes within the 95 – 105 range.

Figure 1-8

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.4%**	**5.4%**	**$689.8**
Commercial			
Small General	104.4%	5.4%	$36.7
General Demand	102.8%	5.4%	$322.0
Large General	98.7%	5.4%	$43.7
Total Commercial	**102.5%**	**5.4%**	**$402.3**
Industrial			
Small Industrial	102.0%	5.4%	$33.5
Medium Industrial	97.3%	5.4%	$57.3
Large Industrial	95.0%	5.4%	$86.8
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**97.0%**	**5.4%**	**$177.6**
Other			
Municipal	98.0%	5.4%	$21.5
Unmetered	100.0%	3.9%	$24.0
Total Other	**99.0%**	**4.6%**	**$45.5**
Total Above-the-line classes	**100.0%**	**5.4%**	**$1,315.2**
BTL (Electric Services)		**0.0%**	**$43.0**
Exports		**0.0%**	**$1.9**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**1.4%**	**$23.5**
Total Revenue		**5.1%**	**$1,387.9**
Revenue Requirement			**$1,387.9**
Revenue Shortfall/Surplus			$0.0

Exhibits	Proposed Changes	Reason for Change
Input Data Tab	Deferred Charges – Other (LED)	Added new category in the Deferred Charges to single out the LED Asset in accordance with financial systems.
Input Data Tab	Deferred Charges Category for FCR (line 68)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Input Data Tab	FCR Deferral (line 265)	Added new category to single out the FCR Deferral in accordance with financial systems.
Input Data Tab	FCR Deferral Allocation (lines 330 and 331)	This was created to allocate FCR Deferral, illustrated in Exhibit 4 Detail, by production and transmission expenses.
Input Data Tab	Misc. Revenue (Lines 442 and 443)	As per the financial tables, included in Misc. Revenue is OM&G reclass due to US GAAP and revenues for Lower Water Street – Block C.
Input Data Tab	Marketing and Sales Allocator (lines 329 – 338)	Allocator's had to be altered to take into account that ELI 2P-RTP is now 0.
Input Data Tab	Marketing and Sales Allocator (lines 339 – 348)	Allocator's had to be altered to take into account that ELI 2P-RTP is now 0.
Input Data Tab Two	Inclusion of LRT to the data set (lines 14, 32, 49, 66, 89, and 105)	
Exhibit 2	DEF. CHG – Other (line 34)	The LED Asset is grouped into this category however directly assigned.
Exhibit 2	DEF. CHG – FCR (line 35)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 2a	DEF. CHG – FCR (lines 19 and 39)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 2b	DEF. CHG – FCR (lines 19 and 39)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 3	DEF. CHG – FCR (lines 19 and 39)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 4	Biomass – Operating Maintenance (line 7)	Added new category in operating and maintenance in accordance with financial systems.
Exhibit 4	FCR Deferral (line 29)	Added new category to single out the FCR Deferral in accordance with financial systems.
Exhibit 4 Detail A	Biomass – Operating Maintenance (line 8)	Added new category in operating and maintenance in accordance with financial systems.

Exhibit 4 Detail A	FCR Deferral (line 20)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 4 Detail A	Direct Expenses (Column 6)	LRT fixed cost added has been included in the direct expense column.
Exhibit 4 Detail B	New Worksheet	This tab was created to functionalize the fixed cost adder of LRT ($4/MWh) across all operating expenses.
Exhibit 5	Oper. & Maint. – Hydro/Wind/Biomass (line 7)	The new OM&G Biomass category is incorporated into this category.
Exhibit 5	FCR Deferral (lines 11 and 34)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 6	FCR Deferral (page 1 lines 9 and 31, page 3 lines 11 and 28)	Added new category in the Deferred Charges to single out the FCR Deferral in accordance with financial systems.
Exhibit 7	LRT (line 21)	Added new category in direct revenue for Bowater under the LRT rate.
Exhibit 9a (annual, Jan – Dec)	LRT	Added new category to illustrate sales, generation and demand analysis for LRT.
Exhibit 9c	LRT (column 15)	Added new category to illustrate LRT's monthly coincident kW Demand
Exhibit 9A	Non-Coincident Demand of Domestic Category (Column 4) is determined jointly for the Non-TOU and TOU rate classes.	Historically, the non-coincident peaks of these two classes were determined separately and then were added together for cost allocation purposes. Such an approach, in view of the treatment of domestic costs in the COSS as one entity, is not appropriate.

RATE STABILIZATION PLAN – RATES AND DEFERRED REVENUES

This Appendix contains the detailed calculations and supporting documents respecting NS Power's requested rates and deferred revenues associated with its Rate Stabilization Plan.

The Attachments provided within this Appendix are as described below. Each Attachment within this Appendix is prepared in the same standard format as the rates related document that appears as part of the Traditional filing, but each of these specific Attachments has been modified to reflect the specifics of the Rate Stabilization Plan. For comparison and reference, we have provided the reference to the Traditional filing document for each Attachment below:

Appendix P	Description	Reference to Traditional Filing
Attachment 1	Proof of Revenues	OR-01
Attachment 2	Revenue Increase Analysis	Appendix M
Attachment 3	Unmetered Class Ratemaking	Appendix I
Attachment 4	Proposed Tariffs	PR-01
Attachment 5	Schedule of Charges	PR-02
Attachment 6	Proposed Regulation Changes	PR-03

2013 Current Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			PRESENT
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2013
Above-the-line Classes	-																	
Residential Sector																		
Non-ETS	4,058.6	$ 0.12638	$ 512.9		$ -	$ -	-	$ -	$ -	4,058.6	$ 512.9	-	$ -	$ -	5.1	$ 10.83	$ 55.2	$ 568.1
ETS	13.7	$ 0.16435	$ 2.3	47.9	$ 0.12638	$ 6.1	153.0	$ 0.06468	$ 9.9	214.6	$ 18.2	-	$ -	$ -	0.1	$ 18.82	$ 2.4	$ 20.6
Total	**4,072.3**		**$ 515.2**	**47.9**		**$ 6.05**	**153.0**		**$ 9.9**	**4,273.2**	**$ 531.1**	**-**		**$ -**	**5.2**		**$ 57.60**	**$ 588.7**
Commercial Sector																		
Small General	39.7	$ 0.13370	$ 5.3	191.6	$ 0.11762	$ 22.5	-		$ -	231.3	$ 27.8	-	$ -	$ -	0.3	$ 12.65	$ 3.6	$ 31.5
General Demand	1,317.2	$ 0.09904	$ 130.5	1,118.1	$ 0.07006	$ 78.3	-		$ -	2,435.3	$ 208.8	7.2	$ 9.276	$ 67.2	-	$ -	$ -	$ 276.0
Large General																		
Without Trans. Own.	249.7	$ 0.07040	$ 17.6							249.7	$ 17.6	0.5	$ 11.702	$ 6.1				$ 23.7
With Trans. Own.	146.6	$ 0.07040	$ 10.3							146.6	$ 10.3	0.3	$ 11.382	$ 3.8				$ 14.1
Sub-total	396.3		$ 27.9							396.3	$ 27.9	0.9		$ 9.9				$ 37.8
Total	**1,753.2**		**$ 163.7**	**1,309.7**		**$ 100.9**				**3,062.9**	**$ 264.5**	**8.1**		**$ 77.1**	**0.3**		**$ 3.6**	**$ 345.2**
Industrial Sector																		
Small Industrial	175.3	$ 0.08965	$ 15.7	82.8	$ 0.06848	$ 5.7				258.2	$ 21.4	1.0	$ 6.854	$ 7.1	258.2			$ 28.5
Medium Industrial	498.8	$ 0.06390	$ 31.9							498.8	$ 31.9	1.5	$ 11.032	$ 16.1				$ 48.0
Large Industrial Firm																		
Without Trans. Own.	55.6	$ 0.06369	$ 3.5							55.6	$ 3.5	0.1	$ 10.469	$ 1.5				$ 5.0
With Trans. Own.	169.2	$ 0.06369	$ 10.8							169.2	$ 10.8	0.3	$ 10.149	$ 2.8				$ 13.6
Sub-total	224.8		$ 14.3							224.8	$ 14.3	0.4		$ 4.3				$ 18.6
Large Industrial Interr.																		
Without Trans. Own.	197.8	$ 0.06369	$ 12.6							197.8	$ 12.6	0.5	$ 7.039	3.6				$ 16.2
With Trans. Own.	498.8	$ 0.06369	$ 31.8							498.8	$ 31.8	1.1	$ 6.719	7.3				$ 39.0
Sub-total	696.6		$ 44.4							696.6	$ 44.4	1.6		10.9				$ 55.2
Total Large Industrial	**921.4**		**$ 58.7**						1	**921.4**	**$ 58.7**	**2.0**		**$ 15.1**				**$ 73.8**
ELI 2P-RTP	-		$ -							-	$ -	2.7	$ -	$ -		$ 20,700.00	$ -	$ -
Total Industrial	**1,595.5**		**$ 106.3**	**82.81**		**$ 5.7**				**1,678.4**	**$ 111.9**	**7.2**		**$ 38.3**	**258.2**		**0.0**	**$ 150.2**
Other																		
Municipal																		
Without Trans. Own.	118.6	$ 0.06609	$ 7.8							118.6	$ 7.8	0.3	$ 10.910	$ 3.6				$ 11.4
With Trans. Own.	74.1	$ 0.06609	$ 4.9							74.1	$ 4.9	0.2	$ 10.590	$ 2.0				$ 6.9
Sub-total	192.6		$ 12.7							192.6	$ 12.7	0.5		$ 5.6				$ 18.3
Unmetered[12]	104.4	$ 0.21398	$ 22.3							104.4	$ 22.3							$ 22.3
Total	**297.0**		**$ 35.1**							**297.0**	**$ 35.1**	**0.5**		**$ 5.6**				**$ 40.6**
Total Above-the-line	**7,718.1**		**$ 820.2**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**9,311.5**	**$ 942.7**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,124.8**
Below-the-line Classes																		
GRLF	18.8	$ 0.05818	$ 1.1							18.8	$ 1.1							$ 1.1
Mersey Additional Energy	178.9	$ 0.05747	$ 10.3							178.9	$ 10.3							$ 10.3
Mersey Contract	189.0	$ 0.05257	$ 9.9							189.0	$ 9.9							$ 9.9
LRT	322.1	$ 0.06577	$ 21.2							322.1	$ 21.2							$ 21.2
GRLF, AE, Mersey Contract and LRT	708.8	$ 0.05995	$ 42.5							708.8	$ 42.5							$ 42.5
LED Capital Costs			$ 1.6								$ 1.6							$ 1.6
Total	**708.8**		**$ 44.1**							**708.8**	**$ 42.5**							**$ 44.1**
Total In-Province	**8,426.9**		**$ 864.2**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**10,020.3**	**$ 986.7**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,168.9**
Exports	**28.9**	**$ 0.06243**	**$ 1.8**							**28.9**	**$ 1.8**							$ 1.8
Total Electric Revenue	**8,455.9**		**$ 866.0**	**1,440.4**		**$ 112.6**	**153.0**		**$ 9.9**	**10,049.2**	**$ 988.5**	**15.8**		**$ 120.9**	**263.7**		**$ 61.2**	**$ 1,170.7**
Misc. Revenues[2]			**$ 22.0**								**$ 22.0**							**$ 22.0**
Total Revenues			**$ 888.0**								**$ 1,010.5**							**$ 1,192.6**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

2013 Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED RATES FORECAST 2013
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	
Above-the-line Classes	-																	
Residential Sector																		
Domestic Service	4,058.6	$ 0.13511	$ 548.4							4,058.6	$ 548.4				5.1	$ 10.83	$ 55.2	$ 603.5
Domestic Service Time of Day	13.7	$ 0.17603	$ 2.4	47.9	$ 0.13511	$ 6.5	153.0	0.06928	$ 10.6	214.6	$ 19.5				0.1	$ 18.82	$ 2.4	$ 21.9
Total	**4,072.3**		**$ 550.8**	**47.9**		**$ 6.47**	**153.0**		**$ 10.6**	**4,273.2**	**$ 567.8**				**5.2**		**$ 57.6**	**$ 625.4**
Commercial Sector																		
Small General	39.7	$ 0.14307	$ 5.7	191.6	$ 0.12587	$ 24.1				231.3	$ 29.8				0.3	$ 12.65	$ 3.6	$ 33.4
General	1,317.2	$ 0.10608	$ 139.7	1,118.1	$ 0.07505	$ 83.9				2,435.3	$ 223.6	7.2	$ 9.935	$ 72.0				$ 295.6
Large General																		
Without Trans. Own.	249.7	$ 0.07536	$ 18.8							249.7	$ 18.8	0.5	$ 12.526	$ 6.5				$ 25.3
With Trans. Own.	146.6	$ 0.07536	$ 11.0							146.6	$ 11.0	0.3	$ 12.206	$ 4.1				$ 15.1
Sub-total	396.3		$ 29.9							396.3	$ 29.9	0.9		$ 10.6				$ 40.5
Total	**1,753.2**		**$ 175.3**	**1,309.7**		**$ 108.0**				**3,062.9**	**$ 283.3**	**8.1**		**$ 82.6**	**0.3**		**$ 3.6**	**$ 369.5**
Industrial Sector																		
Small Industrial	175.3	$ 0.09529	$ 16.7	82.8	$ 0.07278	$ 6.0				258.2	$ 22.7	1.0	$ 7.285	$ 7.5				$ 30.2
Medium Industrial	498.8	$ 0.06817	$ 34.0							498.8	$ 34.0	1.5	$ 11.769	$ 17.2				$ 51.2
Large Industrial Firm																		
Without Trans. Own.	55.6	$ 0.06799	$ 3.8							55.6	$ 3.8	0.1	$ 11.177	$ 1.6				$ 5.3
With Trans. Own.	169.2	$ 0.06799	$ 11.5							169.2	$ 11.5	0.3	$ 10.857	$ 3.0				$ 14.5
Sub-total	224.8		$ 15.3							224.8	$ 15.3	0.4		$ 4.6				$ 19.9
Large Industrial Interruptible																		
Without Trans. Own.	197.8	$ 0.06799	$ 13.4							197.8	$ 13.4	0.5	$ 7.747	$ 3.9				$ 17.4
With Trans. Own.	498.8	$ 0.06799	$ 33.9							498.8	$ 33.9	1.1	$ 7.427	$ 8.0				$ 42.0
Sub-total	696.6		$ 47.4							696.6	$ 47.4	1.6		$ 12.0				$ 59.3
Total Large Industrial	**921.4**		**$ 62.6**							**921.4**	**$ 62.6**	**2.0**		**$ 16.6**				**$ 79.2**
Extra Large Industrial Interruptible	**-**		**$ -**							**-**	**$ -**		$ -	$ -				**$ -**
Total Industrial	**1,595.5**		**$ 113.4**	**82.8**		**$ 6.0**				**1,678.4**	**$ 119.4**	**4.5**		**$ 41.2**	**-**		**$ -**	**$ 160.6**
Other																		
Municipal																		
Without Trans. Own.	118.6	$ 0.07133	$ 8.5							118.6	$ 8.5	0.3	$ 11.775	$ 3.8				$ 12.3
With Trans. Own.	74.1	$ 0.07133	$ 5.3							74.1	$ 5.3	0.2	$ 11.455	$ 2.2				$ 7.4
Sub-total	192.6		$ 13.7							192.6	$ 13.7	0.5		$ 6.0				$ 19.7
Unmetered[1,2]	104.4	$ 0.22431	$ 23.4							104.4	$ 23.4							$ 23.4
Total	**297.0**		**$ 37.2**							**297.0**	**$ 37.2**	**0.5**		**$ 6.0**				**$ 43.2**
Total Above-the-line	**7,718.1**		**$ 876.6**	**1,440.4**		**$ 120.5**	**153.0**		**$ 10.6**	**9,311.5**	**$ 1,007.7**	**13.1**		**$ 129.8**	**5.5**		**$ 61.2**	**$ 1,198.7**
Below-the-line Classes																		
GRLF	18.8	$ 0.05818	$ 1.1							18.8	$ 1.1							$ 1.1
Mersey Additional Energy	178.9	$ 0.05747	$ 10.3							178.9	$ 10.3							$ 10.3
Mersey Contract	189.0	$ 0.05257	$ 9.9							189.0	$ 9.9							$ 9.9
LRT	322.1	$ 0.06577	$ 21.2							322.1	$ 21.2							$ 21.2
GRLF, AE, and Mersey Contract	708.8	$ 0.05995	$ 42.5							708.8	$ 42.5							$ 42.5
LED Capital Costs			$ 1.6							-	$ 1.6							$ 1.6
Total	**708.8**		**$ 44.1**							**708.8**	**44.1**							**$ 44.1**
Total In-Province	**8,426.9**		**$ 920.7**	**1,440.4**		**$ 120.5**	**153.0**		**$ 10.6**	**10,020.3**	**$ 1,051.8**	**13.1**		**$ 129.8**	**5.5**		**$ 61.2**	**$ 1,242.8**
Exports	**28.9**	**$ 0.06243**	**$ 1.8**							**28.9**	**$ 1.8**							**$ 1.8**
Total Electric Revenue	**8,455.9**		**$ 922.5**	**1,440.4**		**$ 120.5**	**153.0**		**$ 10.6**	**10,049.2**	**$ 1,053.6**	**13.1**		**$ 129.8**	**5.5**		**$ 61.2**	**$ 1,244.6**
Misc. Revenues[2]			**$ 22.3**								**$ 22.3**							**$ 22.3**
Total Revenues			**$ 944.8**								**$ 1,075.9**							**$ 1,266.9**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

VARIANCE	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			Revenue
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	Forecasts 2013
Above-the-line Classes	-																	
Residential Sector																		
Non-ETS	-	$ 0.00873	$ 35.4	-	$ -	$ -	-	$ -	$ -	-	$ 35.4	-	$ -	$ -	-	$ -	$ -	$ 35.4
ETS	-	$ 0.01168	$ 0.2	-	$ 0.00873	$ 0.4	-	0.0046001	$ 0.7	-	$ 1.3	-	$ -	$ -	-	$ -	$ -	$ 1.3
Total	-	$ -	$ 35.6	-	$ -	$ 0.42	-	0	$ 0.7	-	$ 36.7	-	$ -	$ -	-	0	$ -	$ 36.7
Commercial Sector																		
Small General	-	$ 0.00937	$ 0.4	-	$ 0.00825	$ 1.6	-	0	$ -	-	$ 2.0	-	$ -	$ -	-	$ -	$ -	$ 2.0
General Demand	-	$ 0.00704	$ 9.3	$ -	$ 0.00499	$ 5.6	-	0	$ -	-	$ 14.8	-	$ 0.66	$ 4.8	-	$ -	$ -	$ 19.6
Large General	-	$ -	$ -	0	$ -	0	0	0	0	-	$ -	-	$ -	$ -	0	0	0	$ -
Without Trans. Own.	-	$ 0.00496	$ 1.2	$ -	$ -	$ -	-	0	$ -	-	$ 1.2	-	$ 0.82	$ 0.4	-	$ -	$ -	$ 1.7
With Trans. Own.	-	$ 0.00496	$ 0.7	0	$ -	0	0	0	0	-	$ 0.7	-	$ 0.82	$ 0.3	0	0	0	$ 1.0
Sub-total	-	$ -	$ 2.0	0	$ -	0	0	0	0	-	$ 2.0	-	$ -	$ 0.7	0	0	0	$ 2.7
Total	-	$ -	$ 11.6	-	$ -	$ 7.2	0	0	0	-	$ 18.8	-	$ -	$ 5.5	-	0	$ -	$ 24.2
Industrial Sector																		
Small Industrial	-	$ 0.00564	$ 1.0	-	$ 0.00430	$ 0.4	-	0	$ -	-	$ 1.3	-	$ 0.43	$ 0.4	(258.2)	$ -	$ -	$ 1.8
Medium Industrial	-	$ 0.00427	$ 2.1	-	$ -	$ -	-	0	$ -	-	$ 2.1	-	$ 0.74	$ 1.1	-	$ -	$ -	$ 3.2
Large Industrial Firm																		
Without Trans. Own.	-	$ 0.00430	$ 0.2	-	$ -	$ -	-	0	$ -	-	$ 0.2	-	$ 0.71	$ 0.1	-	$ -	$ -	$ 0.3
With Trans. Own.	-	$ 0.00430	$ 0.7	0	$ -	0	0	0	0	-	$ 0.7	-	$ 0.71	$ 0.2	0	0	0	$ 0.9
Sub-total	-	$ -	$ 1.0	-	$ -	$ -	-	0	$ -	-	$ 1.0	-	$ -	$ 0.3	-	$ -	$ -	$ 1.3
Large Industrial Interr.																		
Without Trans. Own.	-	$ 0.00430	$ 0.9	-	$ -	$ -	0	0	0	-	$ 0.9	-	$ 0.71	$ 0.4	-	0	$ -	$ 1.2
With Trans. Own.	-	$ 0.00430	$ 2.1	-	$ -	$ -	0	0	0	-	$ 2.1	-	$ 0.71	$ 0.8	-	0	$ -	$ 2.9
Sub-total	-	$ -	$ 3.0	-	$ -	$ -	0	0	0	-	$ 3.0	-	$ -	$ 1.1	-	0	$ -	$ 4.1
Total Large Industrial	-	$ -	$ 4.0	0	$ -	0	0	0	-1	-	$ 4.0	-	$ -	$ 1.4	0	0	0	$ 5.4
Extra Large Industrial Interruptible	-	$ -	$ -	0	$ -	0	0	0	0	-	$ -	(2.7)	$ -	$ -	0	-20700	0	$ -
Total Industrial	-	$ -	$ 7.1	-	$ -	$ 0.4	0	0	0	-	$ 7.4	(2.7)	$ -	$ 2.9	-258.2	0	0	$ 10.4
Other																0		
Municipal																		
Without Trans. Own.	-	$ 0.00524	$ 0.6	0	$ -	0	0	0	0	-	$ 0.6	-	$ 0.87	$ 0.3	0	0	0	$ 0.9
With Trans. Own.	-	$ 0.00524	$ 0.4	0	$ -	0	0	0	0	-	$ 0.4	-	$ 0.87	$ 0.2	0	0	0	$ 0.6
Sub-total	-	$ -	$ 1.0	0	$ -	0	0	0	0	-	$ 1.0	-	$ -	$ 0.4	0	0	0	$ 1.5
Unmetered[12]	-	$ 0.01033	$ 1.1	0	$ -	0	0	0	0	-	$ 1.1	-	$ -	$ -	0	0	0	$ 1.1
Total	-	$ -	$ 2.1	0	$ -	0	0	0	0	-	$ 2.1	-	$ -	$ 0.4	0	0	0	$ 2.5
Total Above-the-line	-	$ -	$ 56.4	-	$ -	$ 7.9	-	0	$ 0.7	-	$ 65.0	(2.7)	0	$ 8.9	(258.2)	0	$ -	$ 73.9
Below-the-line Classes																		
GRLF and Mersey Contract	-	$ -	$ -							-	$ -	-	$ -	$ -	0	0	0	$ -
LED Capital Costs	-	$ -	$ 0.0							-	$ 0.0	-	$ -	$ -	0	0	0	$ 0.0
Total	-	$ -	$ 0.0							-	$ 1.6	-	$ -	$ -	0	0	0	$ 0.0
Total In-Province	-	$ -	$ 56.4	-	$ -	$ 7.9	-	$ -	$ 0.7	-	$ 65.1	(2.7)	$ -	$ 8.9	(258.2)	$ -	$ -	$ 73.9
Exports	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	-	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total Electric Revenue	-	$ -	$ 56.4	-	$ -	$ 7.9	-	$ -	$ 0.7	-	$ 65.1	(2.7)	$ -	$ 8.9	(258.2)	$ -	$ -	$ 73.9
Misc. Revenues[2]			$ 0.4			$ -			$ -		$ 0.4			$ -			$ -	$ 0.4
Total Revenues			$ 56.8			$ -			$ -		$ 65.4			$ -			$ -	$ 74.3

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights
(2) Per kWh charge is not applicable as the class is made up of a number of rates

2014 Current Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			PRESENT
(2013 Proposed Rates)	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2014
Above-the-line Classes	-																	
Residential Sector																		
Non-ETS	4,031.9	$ 0.13511	$ 544.7		$ -	$ -	-	$ -	$ -	4,031.9	$ 544.7	-	$ -	$ -	5.1	$ 10.83	$ 55.4	$ 600.1
ETS	14.4	$ 0.17603	$ 2.5	50.3	$ 0.13511	$ 6.8	160.6	$ 0.06928	$ 11.1	225.3	$ 20.5	-	$ -	$ -	0.1	$ 18.82	$ 2.8	$ 23.3
Total	4,046.3		$ 547.3	50.3		$ 6.79	160.6		$ 11.1	4,257.2	$ 565.2	-		$ -	5.3		$ 58.23	$ 623.4
Commercial Sector																		
Small General	39.3	$ 0.14307	$ 5.6	190.0	$ 0.12587	$ 23.9	-		$ -	229.4	$ 29.5	-	$ -	$ -	0.3	$ 12.65	$ 3.6	$ 33.1
General Demand	1,316.0	$ 0.10608	$ 139.6	1,117.0	$ 0.07505	$ 83.8	-		$ -	2,433.0	$ 223.4	7.0	$ 9.935	$ 69.9	-	$ -	$ -	$ 293.3
Large General																		
Without Trans. Own.	249.7	$ 0.07536	$ 18.8							249.7	$ 18.8	0.5	$ 12.526	$ 6.5				$ 25.3
With Trans. Own.	137.2	$ 0.07536	$ 10.3							137.2	$ 10.3	0.3	$ 12.206	$ 4.1				$ 14.4
Sub-total	387.0		$ 29.2							387.0	$ 29.2	0.9		$ 10.6				$ 39.8
Total	1,742.3		$ 174.4	1,307.1		$ 107.8				3,049.4	$ 282.1	7.9		$ 80.5	0.3		$ 3.6	$ 366.2
Industrial Sector																		
Small Industrial	176.8	$ 0.09529	$ 16.8	83.5	$ 0.07278	$ 6.1				260.3	$ 22.9	1.0	$ 7.285	$ 7.4	260.3			$ 30.3
Medium Industrial	512.8	$ 0.06817	$ 35.0							512.8	$ 35.0	1.4	$ 11.769	$ 17.0				$ 51.9
Large Industrial Firm																		
Without Trans. Own.	54.1	$ 0.06799	$ 3.7							54.1	$ 3.7	0.1	$ 11.177	$ 1.6				$ 5.2
With Trans. Own.	174.6	$ 0.06799	$ 11.9							174.6	$ 11.9	0.3	$ 10.857	$ 3.0				$ 14.9
Sub-total	228.7		$ 15.5							228.7	$ 15.5	0.4		$ 4.6				$ 20.1
Large Industrial Interr.																		
Without Trans. Own.	197.8	$ 0.06799	$ 13.4							197.8	$ 13.4	0.5	$ 7.747	3.9				$ 17.4
With Trans. Own.	495.3	$ 0.06799	$ 33.7							495.3	$ 33.7	1.1	$ 7.427	8.1				$ 41.7
Sub-total	693.1		$ 47.1							693.1	$ 47.1	1.6		12.0				$ 59.1
Total Large Industrial	921.8		$ 62.7						1	921.8	$ 62.7	2.0		$ 16.6				$ 79.2
ELI 2P-RTP	-	$ 0.06737	$ -							-	$ -	2.7	$ -	$ -	-	$ 20,700.00	$ -	$ -
Total Industrial	1,611.4		$ 114.5	83.49		$ 6.1				1,694.8	$ 120.5	7.2		$ 40.9	260.3		0.0	$ 161.5
Other																		
Municipal																		
Without Trans. Own.	117.7	$ 0.07133	$ 8.4							117.7	$ 8.4	0.3	$ 11.775	$ 3.9				$ 12.3
With Trans. Own.	74.1	$ 0.07133	$ 5.3							74.1	$ 5.3	0.2	$ 11.455	$ 2.2				$ 7.4
Sub-total	191.7		$ 13.7							191.7	$ 13.7	0.5		$ 6.1				$ 19.7
Unmetered[12]	97.8	$ 0.22431	$ 21.9							97.8	$ 21.9							$ 21.9
Total	289.5		$ 35.6							289.5	$ 35.6	0.5		$ 6.1				$ 41.7
Total Above-the-line	7,689.5		$ 871.8	1,440.9		$ 120.6	160.6		$ 11.1	9,291.0	$ 1,003.5	15.6		$ 127.4	265.8		$ 61.8	$ 1,192.8
Below-the-line Classes																		
GRLF	18.8	$ 0.05696	$ 1.1							18.8	$ 1.1							$ 1.1
Mersey Additional Energy	178.9	$ 0.05724	$ 10.2							178.9	$ 10.2							$ 10.2
Mersey Contract	189.0	$ 0.05176	$ 9.8							189.0	$ 9.8							$ 9.8
LRT	322.1	$ 0.06786	$ 21.9							322.1	$ 21.9							$ 21.9
GRLF, AE, and Mersey Contract	708.8	$ 0.06060	$ 43.0							708.8	$ 43.0							$ 43.0
LED Capital Costs			$ 3.5							-	$ 3.5							$ 3.5
Total	708.8		$ 46.5							708.8	$ 46.5							$ 46.5
Total In-Province	8,398.3		$ 918.2	1,440.9		$ 120.6	160.6		$ 11.1	9,999.8	$ 1,050.0	15.6		$ 127.4	265.8		$ 61.8	$ 1,239.2
Exports	29.5	$ 0.06583	$ 1.9							29.5	$ 1.9							$ 1.9
Total Electric Revenue	8,427.8		$ 920.1	1,440.9		$ 120.6	160.6		$ 11.1	10,029.3	$ 1,051.9	15.6		$ 127.4	265.8		$ 61.8	$ 1,241.2
Misc. Revenues[2]			$ 22.9								$ 22.9							$ 22.9
Total Revenues			$ 943.0								$ 1,074.8							$ 1,264.0

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

2014 Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED
Above-the-line Classes	Energy in GWh -	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2014
Residential Sector																		
Domestic Service	4,031.9	$ 0.14241	$ 574.2							4,031.9	$ 574.2				5.1	$ 10.83	$ 55.4	$ 629.6
Domestic Service Time of Day	14.4	$ 0.18596	$ 2.7	50.3	$ 0.14241	$ 7.2	160.6	0.07318	$ 11.8	225.3	$ 21.6				0.1	$ 18.82	$ 2.8	$ 24.4
Total	4,046.3		$ 576.9	50.3		$ 7.16	160.6		$ 11.8	4,257.2	$ 595.8				5.3		$ 58.2	$ 654.0
Commercial Sector																		
Small General	39.3	$ 0.15121	$ 5.9	190.0	$ 0.13303	$ 25.3				229.4	$ 31.2				0.3	$ 12.65	$ 3.6	$ 34.8
General	1,316.0	$ 0.11211	$ 147.5	1,117.0	$ 0.07931	$ 88.6				2,433.0	$ 236.1	7.0	$ 10.500	$ 73.8				$ 310.0
Large General																		
Without Trans. Own.	249.7	$ 0.08022	$ 20.0							249.7	$ 20.0	0.5	$ 13.334	$ 6.9				$ 27.0
With Trans. Own.	137.2	$ 0.08022	$ 11.0							137.2	$ 11.0	0.3	$ 13.014	$ 4.4				$ 15.4
Sub-total	387.0		$ 31.0							387.0	$ 31.0	0.9		$ 11.3				$ 42.3
Total	1,742.3		$ 184.5	1,307.1		$ 113.9				3,049.4	$ 298.4	7.9		$ 85.1	0.3		$ 3.6	$ 387.1
Industrial Sector																		
Small Industrial	176.8	$ 0.10083	$ 17.8	83.5	$ 0.07701	$ 6.4				260.3	$ 24.3	1.0	$ 7.709	$ 7.8				$ 32.0
Medium Industrial	512.8	$ 0.07233	$ 37.1							512.8	$ 37.1	1.4	$ 12.487	$ 18.0				$ 55.1
Large Industrial Firm																		
Without Trans. Own.	54.1	$ 0.07241	$ 3.9							54.1	$ 3.9	0.1	$ 11.903	$ 1.7				$ 5.6
With Trans. Own.	174.6	$ 0.07241	$ 12.6							174.6	$ 12.6	0.3	$ 11.583	$ 3.2				$ 15.9
Sub-total	228.7		$ 16.6							228.7	$ 16.6	0.4		$ 4.9				$ 21.4
Large Industrial Interruptible																		
Without Trans. Own.	197.8	$ 0.07241	$ 14.3							197.8	$ 14.3	0.5	$ 8.473	$ 4.3				$ 18.6
With Trans. Own.	495.3	$ 0.07241	$ 35.9							495.3	$ 35.9	1.1	$ 8.153	$ 8.8				$ 44.7
Sub-total	693.1		$ 50.2							693.1	$ 50.2	1.6		$ 13.2				$ 63.3
Total Large Industrial	921.8		$ 66.7							921.8	$ 66.7	2.0		$ 18.0				$ 84.8
Extra Large Industrial Interruptible	-	$ 0.06737	$ -							-	$ -	2.7	$ -	$ -	-	$ 20,700	$ -	$ -
Total Industrial	1,611.4		$ 121.7	83.5		$ 6.4				1,694.8	$ 128.1	7.2		$ 43.8	-		$ -	$ 171.9
Other																		
Municipal																		
Without Trans. Own.	117.7	$ 0.07541	$ 8.9							117.7	$ 8.9	0.3	$ 12.449	$ 4.1				$ 13.0
With Trans. Own.	74.1	$ 0.07541	$ 5.6							74.1	$ 5.6	0.2	$ 12.129	$ 2.3				$ 7.9
Sub-total	191.7		$ 14.5							191.7	$ 14.5	0.5		$ 6.4				$ 20.9
Unmetered[12]	97.8	$ 0.23529	$ 23.0							97.8	$ 23.0							$ 23.0
Total	289.5		$ 37.5							289.5	$ 37.5	0.5		$ 6.4				$ 43.9
Total Above-the-line	7,689.5		$ 920.5	1,440.9		$ 127.5	160.6		$ 11.8	9,291.0	$ 1,059.7	15.6		$ 135.4	5.6		$ 61.8	$ 1,256.9
Below-the-line Classes																		
GRLF	18.8	$ 0.05696	$ 1.1							18.8	$ 1.1							$ 1.1
Mersey Additional Energy	178.9	$ 0.05724	$ 10.2							178.9	$ 10.2							$ 10.2
Mersey Contract	189.0	$ 0.05176	$ 9.8							189.0	$ 9.8							$ 9.8
GRLF, AE, and Mersey Contract	708.8	$ 0.06060	$ 43.0							708.8	$ 43.0							$ 43.0
LED Capital Costs	3.5	$ 1.01766	$ 3.6							3.5	$ 3.6							$ 3.6
Total	708.8		$ 46.6							708.8	46.6							$ 46.6
Total In-Province	8,398.3		$ 967.1	1,440.9		$ 127.5	160.6		$ 11.8	9,999.8	$ 1,106.3	15.6		$ 135.4	5.6		$ 61.8	$ 1,303.5
Exports	29.5	$ 0.06583	$ 1.9							29.5	$ 1.9							$ 1.9
Total Electric Revenue	8,427.8		$ 969.0	1,440.9		$ 127.5	160.6		$ 11.8	10,029.3	$ 1,108.2	15.6		$ 135.4	5.6		$ 61.8	$ 1,305.4
Misc. Revenues[2]			$ 23.2								$ 23.2							$ 23.2
Total Revenues			$ 992.2								$ 1,131.4							$ 1,328.6

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

VARIANCE	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			Revenue
	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	Forecasts 2014
Above-the-line Classes	-																	
Residential Sector																		
Non-ETS	-	$ 0.00730	$ 29.4	-	$ -	$ -	-	$ -	$ -	-	$ 29.4	-	$ -	$ -	-	$ -	$ -	**$ 29.4**
ETS	-	$ 0.00993	$ 0.1	-	$ 0.00730	$ 0.4	-	0.0039024	$ 0.6	-	$ 1.1	-	$ -	$ -	-	$ -	$ -	**$ 1.1**
Total	**-**	**$ -**	**$ 29.6**	**-**	**$ -**	**$ 0.37**	**-**	**0**	**$ 0.6**	**-**	**$ 30.6**	**-**	**$ -**	**$ -**	**-**	**0**	**$ -**	**$ 30.6**
Commercial Sector																		
Small General	-	$ 0.00814	$ 0.3	-	$ 0.00716	$ 1.4	-	0	$ -	-	$ 1.7	-	$ -	$ -	-	$ -	$ -	**$ 1.7**
General Demand	-	$ 0.00603	$ 7.9	$ -	$ 0.00426	$ 4.8	-	0	$ -	-	$ 12.7	-	$ 0.56	$ 4.0	-	$ -	$ -	**$ 16.7**
Large General	-	$ -	$ -	0	$ -	0	0	0	0	-	$ -	-	$ -	$ -	0	0	0	**$ -**
Without Trans. Own.	-	$ 0.00486	$ 1.2	$ -	$ -	$ -	-	0	$ -	-	$ 1.2	-	$ 0.81	$ 0.4	-	$ -	$ -	**$ 1.6**
With Trans. Own.	-	$ 0.00486	$ 0.7	0	$ -	0	0	0	0	-	$ 0.7	-	$ 0.81	$ 0.3	0	0	0	**$ 0.9**
Sub-total	-	$ -	$ 1.9	0	$ -	0	0	0	0	-	$ 1.9	-	$ -	$ 0.7	0	0	0	**$ 2.6**
Total	**-**	**$ -**	**$ 10.1**	**-**	**$ -**	**$ 6.1**	**0**	**0**	**0**	**-**	**$ 16.3**	**-**	**$ -**	**$ 4.7**	**-**	**0**	**$ -**	**$ 20.9**
Industrial Sector																		
Small Industrial	-	$ 0.00554	$ 1.0	-	$ 0.00423	$ 0.4	-	0	$ -	-	$ 1.3	-	$ 0.42	$ 0.4	(260.3)	$ -	$ -	**$ 1.8**
Medium Industrial	-	$ 0.00416	$ 2.1	-	$ -	$ -	-	0	$ -	-	$ 2.1	-	$ 0.72	$ 1.0	-	$ -	$ -	**$ 3.2**
Large Industrial Firm																		
Without Trans. Own.	-	$ 0.00442	$ 0.2	-	$ -	$ -	-	0	$ -	-	$ 0.2	-	$ 0.73	$ 0.1	-	$ -	$ -	**$ 0.3**
With Trans. Own.	-	$ 0.00442	$ 0.8	0	$ -	0	0	0	0	-	$ 0.8	-	$ 0.73	$ 0.2	0	0	0	**$ 1.0**
Sub-total	-	$ -	$ 1.0	-	$ -	$ -	-	0	$ -	-	$ 1.0	-	$ -	$ 0.3	-	$ -	$ -	**$ 1.3**
Large Industrial Interr.																		
Without Trans. Own.	-	$ 0.00442	$ 0.9	-	$ -	$ -	0	0	0	-	$ 0.9	-	$ 0.73	$ 0.4	-	0	$ -	**$ 1.2**
With Trans. Own.	-	$ 0.00442	$ 2.2	-	$ -	$ -	0	0	0	-	$ 2.2	-	$ 0.73	$ 0.8	-	0	$ -	**$ 3.0**
Sub-total	-	$ -	$ 3.1	-	$ -	$ -	0	0	0	-	$ 3.1	-	$ -	$ 1.2	-	0	$ -	**$ 4.2**
Total Large Industrial	**-**	**$ -**	**$ 4.1**	**0**	**$ -**	**0**	**0**	**0**	-1	**-**	**$ 4.1**	**-**	**$ -**	**$ 1.5**	**0**	**0**	**0**	**$ 5.5**
Extra Large Industrial Interruptible	**-**	**$ (0.00000)**	**$ -**	**0**	**$ -**	**0**	**0**	**0**	0	**-**	**$ -**	**-**	**$ -**	**$ -**	**0**	**0**	**0**	**$ -**
Total Industrial	**-**	**$ -**	**$ 7.2**	**-**	**$ -**	**$ 0.4**	**0**	**0**	**0**	**-**	**$ 7.5**	**-**	**$ -**	**$ 2.9**	**-260.3**	**0**	**0**	**$ 10.5**
Other																0		
Municipal																		
Without Trans. Own.	-	$ 0.00408	$ 0.5	0	$ -	0	0	0	0	-	$ 0.5	-	$ 0.67	$ 0.2	0	0	0	**$ 0.7**
With Trans. Own.	-	$ 0.00408	$ 0.3	0	$ -	0	0	0	0	-	$ 0.3	-	$ 0.67	$ 0.1	0	0	0	**$ 0.4**
Sub-total	-	$ -	$ 0.8	0	$ -	0	0	0	0	-	$ 0.8	-	$ -	$ 0.4	0	0	0	**$ 1.1**
Unmetered[12]	-	$ 0.01098	$ 1.1	0	$ -	0	0	0	0	-	$ 1.1	-	$ -	$ -	0	0	0	**$ 1.1**
Total	-	$ -	$ 1.9	0	$ -	0	0	0	0	-	$ 1.9	-	$ -	$ 0.4	0	0	0	**$ 2.2**
Total Above-the-line	**-**	**$ -**	**$ 48.8**	**-**	**$ -**	**$ 6.8**	**-**	**0**	**$ 0.6**	**-**	**$ 56.2**	**-**	**0**	**$ 7.9**	**(260.3)**	**0**	**$ -**	**$ 64.2**
Below-the-line Classes																		
GRLF and Mersey Contract	-	$ -	$ -							-	$ -	-	$ -	$ -	0	0	0	**$ -**
LED Capital Costs	3.5	$ 1.01766	$ 0.1							3.5	$ 0.1	-	$ -	$ -	0	0	0	**$ 0.1**
Total	**-**	**$ -**	**$ 0.1**							**-**	**$ 0.1**	**-**	**$ -**	**$ -**	**0**	**0**	**0**	**$ 0.1**
Total In-Province	**-**	**$ -**	**$ 48.9**	**-**	**$ -**	**$ 6.8**	**-**	**$ -**	**$ 0.6**	**-**	**$ 56.3**	**-**	**$ -**	**$ 7.9**	**(260.3)**	**$ -**	**$ -**	**$ 64.3**
Exports	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**-**	**$ -**	**$ -**	**-**	**$ -**	**$ -**	**$ -**
Total Electric Revenue	**-**	**$ -**	**$ 48.9**	**-**	**$ -**	**$ 6.8**	**-**	**$ -**	**$ 0.6**	**-**	**$ 56.3**	**-**	**$ -**	**$ 7.9**	**(260.3)**	**$ -**	**$ -**	**$ 64.3**
Misc. Revenues[2]			**$ 0.3**			**$ -**			**$ -**		**$ 0.3**			**$ -**			**$ -**	**$ 0.3**
Total Revenues			**$ 49.2**			**$ -**			**$ -**		**$ 56.7**			**$ -**			**$ -**	**$ 64.6**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights
(2) Per kWh charge is not applicable as the class is made up of a number of rates

2013 REVENUE INCREASE ANALYSIS - RATE STABILIZATION

Rate Classes	2013 Sales (GWh's)	2013 Revenue at current rates before cost adjustment clauses	2012 FAM AA	2012 FAM BA	Revenue at current rates including 2012 AA/BA	Proposed Revenues 2013 Before Riders and with Rate Stabilization			AA Component				BA Component				2013 Revenue reflective of all FAM components		
Columns	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**	**R**	**S**
						Amount	Increase	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
ATL																			
Residential	**4,273.2**	**$588,717,083**	**$15,729,855**	**$13,940,592**	**$618,387,531**	**$625,410,981**	**$36,693,898**	**5.9%**	**$15,729,855**	**$0**	**($15,729,855)**	**-2.5%**	**$13,940,592**	**$11,528,175**	**($2,412,417)**	**-0.4%**	**636,939,156.62**	**18,551,625.92**	**3.0%**
Small General	231.3	$31,454,192	$836,570	$784,960	$33,075,722	$33,404,954	$1,950,762	5.9%	$836,570	$0	($836,570)	-2.5%	$784,960	$663,040	($121,920)	-0.4%	34,067,993.68	992,271.66	3.0%
General Demand	2,435.3	$275,984,112	$9,236,101	$9,197,989	$294,418,202	$295,610,504	$19,626,392	6.7%	$9,236,101	$0	($9,236,101)	-3.1%	$9,197,989	$7,640,244	($1,557,745)	-0.5%	303,250,747.71	8,832,546.05	3.0%
Large General	396.3	$37,795,519	$1,348,850	$1,443,410	$40,587,779	$40,464,264	$2,668,746	6.6%	$1,348,850	$0	($1,348,850)	-3.3%	$1,443,410	$1,341,147	($102,262)	-0.3%	41,805,411.91	1,217,633.36	3.0%
Total Commercial	**3,062.9**	**$345,233,823**	**$11,421,520**	**$11,426,359**	**$368,081,702**	**$369,479,722**	**$24,245,899**	**6.6%**	**$11,421,520**	**$0**	**($11,421,520)**	**-3.1%**	**$11,426,359**	**$9,644,431**	**($1,781,928)**	**-0.5%**	**379,124,153.29**	**11,042,451.07**	**3.0%**
Small Industrial	258.2	$28,459,582	$834,757	$876,178	$30,170,517	$30,248,065	$1,788,484	5.9%	$834,757	$0	($834,757)	-2.8%	$876,178	$827,567	($48,612)	-0.2%	31,075,632.13	905,115.50	3.0%
Medium Industrial	498.8	$47,959,530	$1,569,891	$1,659,488	$51,188,909	$51,159,930	$3,200,400	6.3%	$1,569,891	$0	($1,569,891)	-3.1%	$1,659,488	$1,564,646	($94,842)	-0.2%	52,724,576.65	1,535,667.28	3.0%
Large Industrial - Firm	*224.8*	*$18,598,529*	*$721,583*	*$796,880*	*$20,116,992*	$19,860,991	*$1,376,131*	*6.8%*	*$721,583*	*$0*	*($721,583)*	*-3.6%*	*$796,880*	*$747,144*	*($49,736)*	*-0.2%*	*20,608,134.92*	*491,143.19*	*2.4%*
Large Industrial - Interruptible	*696.6*	*$55,222,023*	*$2,153,715*	*$2,378,457*	*$59,754,194*	$59,344,265	*$4,009,876*	*6.7%*	*$2,153,715*	*$0*	*($2,153,715)*	*-3.6%*	*$2,378,457*	*$2,314,922*	*($63,535)*	*-0.1%*	*61,659,186.85*	*1,904,992.39*	*3.2%*
Total Large Industrial	921.4	$73,820,552	$2,875,298	$3,175,337	$79,871,186	$79,205,256	$5,384,705	6.7%	$2,875,298	$0	($2,875,298)	-3.6%	$3,175,337	$3,062,066	($113,271)	-0.1%	82,267,321.76	2,396,135.59	3.0%
ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	0.00	0.00	N/A
Total Industrial	**1,678.4**	**$150,239,663**	**$5,279,946**	**$5,711,003**	**$161,230,612**	**$160,613,252**	**$10,373,588**	**6.4%**	**$5,279,946**	**$0**	**($5,279,946)**	**-3.3%**	**$5,711,003**	**$5,454,279**	**($256,724)**	**-0.2%**	**166,067,530.54**	**4,836,918.37**	**3.0%**
Municipal	192.6	$18,286,843	$665,963	$716,472	$19,669,277	$19,740,844	$1,454,001	7.4%	$665,963	$0	($665,963)	-3.4%	$716,472	$525,575	($190,896)	-1.0%	20,266,419.89	597,142.74	3.0%
Unmetered	104.4	$22,338,108	$365,351	$422,941	$23,126,401	$23,416,622	$1,078,514	4.7%	$365,351	$0	($365,351)	-1.6%	$422,941	$403,570	($19,371)	-0.1%	23,820,192.61	693,792.02	3.0%
Total Other	**297.0**	**$40,624,951**	**$1,031,314**	**$1,139,413**	**$42,795,678**	**$43,157,467**	**$2,532,516**	**5.9%**	**$1,031,314**	**$0**	**($1,031,314)**	**-2.4%**	**$1,139,413**	**$929,146**	**($210,267)**	**-0.5%**	**44,086,612.50**	**1,290,934.76**	**3.0%**
Total ATL Classes	**9,311.5**	**$1,124,815,521**	**$33,462,635**	**$32,217,367**	**$1,190,495,523**	**$1,198,661,422**	**$73,845,902**	**6.2%**	**$33,462,635**	**$0**	**($33,462,635)**	**-2.8%**	**$32,217,367**	**$27,556,031**	**($4,661,336)**	**-0.4%**	**1,226,217,452.96**	**35,721,930.11**	**3.0%**
BTL (Electric)																			
GRLF	18.8	$1,094,660	$0	$0	$1,094,660	$1,094,660	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	1,094,660.00	0.00	0.0%
Mersey Additional Energy	178.9	$10,282,532	$0	$419,451	$10,701,983	$10,282,532	$0	0.0%	$0	$0	$0	0.0%	$419,451	$290,429	($129,022)	-1.2%	10,572,960.53	(129,022.01)	-1.2%
LRT	322.1	$21,183,202	$879,406	$1,219,578	$23,282,186	$21,183,202	$0	0.0%	$879,406	$0	($879,406)	-3.8%	$1,219,578	$1,330,573	$110,995	0.5%	22,513,775.35	(768,410.98)	-3.3%
Bowater Mersey	189.0	$9,934,827	$0	$0	$9,934,827	$9,934,827	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	9,934,827.00	0.00	0.0%
Total BTL (Electric) Classes	**708.8**	**$42,495,221**	**$879,406**	**$1,639,029**	**$45,013,656**	**$42,495,221**	**$0**	**0.0%**	**$879,406**	**$0**	**($879,406)**	**-2.0%**	**$1,639,029**	**$1,621,002**	**($18,027)**	**0.0%**	**44,116,222.88**	**(897,433.00)**	**-2.0%**
LED SL Capital Costs**		$1,565,170	$0	$0	$1,565,170	$1,612,125	$46,955	3.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	1,612,125.10	46,955.10	3.0%
In Province Total	**10,020.3**	**$1,168,875,912**	**$34,342,042**	**$33,856,395**	**$1,237,074,349**	**$1,242,768,768**	**$73,892,857**	**6.0%**	**$34,342,042**	**$0**	**($34,342,042)**	**-2.8%**	**$33,856,395**	**$29,177,033**	**($4,679,363)**	**-0.4%**	**1,271,945,800.94**	**34,871,452.22**	**2.8%**
Export	28.9	$1,806,823	$0	$0	$1,806,823	$1,806,823	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	1,806,823.00	0.00	0.0%
Total Electric Sales	**10,049.2**	**$1,170,682,735**	**$34,342,042**	**$33,856,395**	**$1,238,881,172**	**$1,244,575,591**	**$73,892,857**	**6.0%**	**$34,342,042**	**$0**	**($34,342,042)**	**-2.8%**	**$33,856,395**	**$29,177,033**	**($4,679,363)**	**-0.4%**	**1,273,752,623.94**	**34,871,452.22**	**2.8%**
Misc Revenue	701.7	$21,959,249	$0	$0	$21,959,249	$22,315,097	$355,849	1.6%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	22,315,097.38	355,848.57	1.6%
Grand Total	**10,750.9**	**$1,192,641,983**	**$34,342,042**	**$33,856,395**	**$1,260,840,421**	**$1,266,890,689**	**$74,248,705**	**5.9%**	**$34,342,042**	**$0**	**($34,342,042)**	**-2.7%**	**$33,856,395**	**$29,177,033**	**($4,679,363)**	**-0.4%**	**1,296,067,721.31**	**35,227,300.79**	**2.8%**

* The 2012 FAM AA/BA Figures have been adjusted to reflect the 2013 LRT Load

**LED Capital Costs will be updated at the time of the capital work order

2014 REVENUE INCREASE ANALYSIS - RATE STABILIZATION

							Proposed Revenues 2014 Before Riders and with Rate Stabilization			AA Component				BA Component				2014 Revenue reflective of all FAM components		
1	Rate Classes	2014 Sales (GWh's)	2014 Revenue at current rates before cost adjustment clauses	2013 FAM AA	2013 FAM BA	Revenue at current rates including 2013 BA														
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	**ATL**																			
5	**Residential**	**4,257.2**	**$623,421,599**	**$0**	**$11,528,175**	**$634,949,774**	**$653,998,267**	**$30,576,668**	**4.8%**	**$0**	**$0**	**$0**	**0.0%**	**$11,528,175**	**$0**	**($11,528,175)**	**-1.8%**	**$653,998,267**	**$19,048,493**	**3.0%**
6																				
7	Small General	229.4	$33,148,114	$0	$663,040	$33,811,154	$34,825,489	$1,677,374	5.0%	$0	$0	$0	0.0%	$663,040	$0	($663,040)	-2.0%	$34,825,489	$1,014,335	3.0%
8	General Demand	2,433.0	$293,286,628	$0	$7,640,244	$300,926,872	$309,954,678	$16,668,050	5.5%	$0	$0	$0	0.0%	$7,640,244	$0	($7,640,244)	-2.5%	$309,954,678	$9,027,806	3.0%
9	Large General	387.0	$39,770,145	$0	$1,341,147	$41,111,293	$42,344,632	$2,574,486	6.3%	$0	$0	$0	0.0%	$1,341,147	$0	($1,341,147)	-3.3%	$42,344,632	$1,233,339	3.0%
10	**Total Commercial**	**3,049.4**	**$366,204,888**	**$0**	**$9,644,431**	**$375,849,319**	**$387,124,799**	**$20,919,911**	**5.6%**	**$0**	**$0**	**$0**	**0.0%**	**$9,644,431**	**$0**	**($9,644,431)**	**-2.6%**	**$387,124,799**	**$11,275,480**	**3.0%**
11																				
12	Small Industrial	260.3	$30,276,493	$0	$827,567	$31,104,059	$32,037,181	$1,760,688	5.7%	$0	$0	$0	0.0%	$827,567	$0	($827,567)	-2.7%	$32,037,181	$933,122	3.0%
13	Medium Industrial	512.8	$51,945,620	$0	$1,564,646	$53,510,267	$55,115,575	$3,169,954	5.9%	$0	$0	$0	0.0%	$1,564,646	$0	($1,564,646)	-2.9%	$55,115,575	$1,605,308	3.0%
14	*Large Industrial - Firm*	*228.7*	*$20,121,152*	*$0*	*$747,144*	*$20,868,296*	*$21,434,038*	*$1,312,886*	*6.3%*	*$0*	*$0*	*$0*	*0.0%*	*$747,144*	*$0*	*($747,144)*	*-3.6%*	*$21,434,038*	*$565,742*	*2.7%*
15	*Large Industrial - Interruptible*	*693.1*	*$59,131,221*	*$0*	*$2,314,922*	*$61,446,143*	*$63,349,834*	*$4,218,612*	*6.9%*	*$0*	*$0*	*$0*	*0.0%*	*$2,314,922*	*$0*	*($2,314,922)*	*-3.8%*	*$63,349,834*	*$1,903,691*	*3.1%*
16	Total Large Industrial	921.8	$79,252,373	$0	$3,062,066	$82,314,438	*$84,783,872*	*$5,531,499*	6.7%	$0	$0	$0	0.0%	$3,062,066	$0	($3,062,066)	-3.7%	*$84,783,872*	$2,469,433	3.0%
17	ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	**Total Industrial**	**1,694.8**	**$161,474,486**	**$0**	**$5,454,279**	**$166,928,765**	**$171,936,627**	**$10,462,142**	**6.3%**	**$0**	**$0**	**$0**	**0.0%**	**$5,454,279**	**$0**	**($5,454,279)**	**-3.3%**	**$171,936,627**	**$5,007,863**	**3.0%**
19																				
20	Municipal	191.7	$19,730,300	$0	$525,575	$20,255,876	$20,863,552	$1,133,252	5.6%	$0	$0	$0	0.0%	$525,575	$0	($525,575)	-2.6%	$20,863,552	$607,676	3.0%
21	Unmetered	97.8	$21,940,358	$0	$403,570	$22,343,928	$23,014,246	$1,073,888	4.8%	$0	$0	$0	0.0%	$403,570	$0	($403,570)	-1.8%	$23,014,246	$670,318	3.0%
22	**Total Other**	**289.5**	**$41,670,658**	**$0**	**$929,146**	**$42,599,804**	**$43,877,798**	**$2,207,140**	**5.2%**	**$0**	**$0**	**$0**	**0.0%**	**$929,146**	**$0**	**($929,146)**	**-2.2%**	**$43,877,798**	**$1,277,994**	**3.0%**
23																				
24	**Total ATL Classes**	**9,291.0**	**$1,192,771,631**	**$0**	**$27,556,031**	**$1,220,327,662**	**$1,256,937,492**	**$64,165,861**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$27,556,031**	**$0**	**($27,556,031)**	**-2.3%**	**$1,256,937,492**	**$36,609,830**	**3.0%**
25																				
26	**BTL (Electric)**																			
27	GRLF	18.8	$1,071,642	$0	$0	$1,071,642	$1,071,642	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,071,642	$0	0.0%
28	Mersey Additional Energy	178.9	$10,241,381	$0	$290,429	$10,531,810	$10,241,381	$0	0.0%	$0	$0	$0	0.0%	$290,429	$0	($290,429)	-2.8%	$10,241,381	($290,429)	-2.8%
	LRT	322.1	$21,856,349	$0	$1,330,573	$23,186,922	$21,856,349	$0	0.0%	$0	$0	$0	0.0%	$1,330,573	$0	($1,330,573)	-5.7%	$21,856,349	($1,330,573)	-5.7%
29	Bowater Mersey	189.0	$9,782,311	$0	$0	$9,782,311	$9,782,311	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$9,782,311	$0	0.0%
30	**Total BTL (Electric) Classes**	**708.8**	**$42,951,683**	**$0**	**$1,621,002**	**$44,572,685**	**$42,951,683**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$1,621,002**	**$0**	**($1,621,002)**	**-3.6%**	**$42,951,683**	**($1,621,002)**	**-3.6%**
31																				
32	LED SL Capital Costs**		$3,498,726	$0	$0	$3,498,726	$3,603,688	$104,962	3.0%	$0	**$0**	**$0**	**N/A**	$0	**$0**	**$0**	**N/A**	$3,603,688	$104,962	3.0%
33																				
34																				
35	**In Province Total**	**9,999.8**	**$1,239,222,040**	**$0**	**$29,177,033**	**$1,268,399,073**	**$1,303,492,862**	**$64,270,822**	**5.1%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,303,492,862**	**$35,093,790**	**2.8%**
36																				
37	Export	29.5	$1,943,419	$0	$0	$1,943,419	$1,943,419	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,943,419	$0	0.0%
38																				
39	**Total Electric Sales**	**10,029.3**	**$1,241,165,459**	**$0**	**$29,177,033**	**$1,270,342,492**	**$1,305,436,281**	**$64,270,822**	**5.1%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,305,436,281**	**$35,093,790**	**2.8%**
40																				
41	Misc Revenue	710.6	$22,871,177	$0	$0	$22,871,177	$23,190,143	$318,966	1.4%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$23,190,143	$318,966	1.4%
42																				
43	**Grand Total**	**10,739.9**	**$1,264,036,636**	**$0**	**$29,177,033**	**$1,293,213,669**	**$1,328,626,424**	**$64,589,788**	**5.0%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,328,626,424**	**$35,412,755**	**2.7%**
44																				

45
46 * The figures for LRT have been adjusted to reflect the correct load
47 **LED Capital Costs will be updated at the time of the capital work order

2013 REVENUE INCREASE DEFERRAL UNDER RATE STABILIZATION PLAN

Rate Classes	2013 Sales (GWh's)	2013 Revenue at current rates before cost adjustment clauses	2012 FAM AA	2012 FAM BA	Revenue at current rates including 2012 AA/BA	2013 Proposed Revenues With Riders Before Rate Stabilization	2013 Proposed Revenues With Riders After Rate Stabilization	Revenue Increase Deferral by Rate Class by the end of 2014			
Columns	A	B	C	D	E	F	G	H	I	J	K
						Amount	Amount	2013 Deferred Amount	Fixed Cost Contribution from the NPPH Mill	Total Interest Associated with 2013 Deferral by the end of 2014	Total 2013 Deferred Amount
ATL											
Residential	**4,273.2**	**$588,717,083**	**$15,729,855**	**$13,940,592**	**$618,387,531**	**$668,084,918**	**$636,939,157**	**$31,145,761**	**$0**	**$3,741,791**	**$34,887,552**
Small General	231.3	$31,454,192	$836,570	$784,960	$33,075,722	$35,741,794	$34,067,994	$1,673,800	$0	$201,087	$1,874,887
General Demand	2,435.3	$275,984,112	$9,236,101	$9,197,989	$294,418,202	$315,426,844	$303,250,748	$12,176,096	$0	$1,462,812	$13,638,909
Large General	396.3	$37,795,519	$1,348,850	$1,443,410	$40,587,779	$43,491,959	$41,805,412	$1,686,547	$0	$202,618	$1,889,165
Total Commercial	**3,062.9**	**$345,233,823**	**$11,421,520**	**$11,426,359**	**$368,081,702**	**$394,660,597**	**$379,124,153**	**$15,536,444**	**$0**	**$1,866,518**	**$17,402,962**
Small Industrial	258.2	$28,459,582	$834,757	$876,178	$30,170,517	$32,566,633	$31,075,632	$1,491,000	$0	$179,126	$1,670,126
Medium Industrial	498.8	$47,959,530	$1,569,891	$1,659,488	$51,188,909	$55,050,699	$52,724,577	$2,326,122	$0	$279,456	$2,605,578
Large Industrial - Firm	*224.8*	*$18,598,529*	*$721,583*	*$796,880*	*$20,116,992*	$21,340,066	$20,608,135	$731,931	$0	$87,933	$819,864
Large Industrial - Interruptible	*696.6*	*$55,222,023*	*$2,153,715*	*$2,378,457*	*$59,754,194*	$64,049,118	$61,659,187	$2,389,931	$0	$287,122	$2,677,053
Total Large Industrial	921.4	$73,820,552	$2,875,298	$3,175,337	$79,871,186	$85,389,184	$82,267,322	$3,121,862	$0	$375,054	$3,496,916
ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Industrial	**1,678.4**	**$150,239,663**	**$5,279,946**	**$5,711,003**	**$161,230,612**	**$173,006,515**	**$166,067,531**	**$6,938,985**	**$0**	**$662,176**	**$7,772,621**
Municipal	192.6	$18,286,843	$665,963	$716,472	$19,669,277	$20,919,667	$20,266,420	$653,247	$0	$78,480	$731,727
Unmetered	104.4	$22,338,108	$365,351	$422,941	$23,126,401	$25,036,953	$23,820,193	$1,216,760	$0	$146,179	$1,362,939
Total Other	**297.0**	**$40,624,951**	**$1,031,314**	**$1,139,413**	**$42,795,678**	**$45,956,620**	**$44,086,613**	**$1,870,007**	**$0**	**$224,659**	**$2,094,666**
Total ATL Classes	**9,311.5**	**$1,124,815,521**	**$33,462,635**	**$32,217,367**	**$1,190,495,523**	**$1,281,708,650**	**$1,226,217,453**	**$55,491,197**	**$0**	**$6,495,144**	**$62,157,800**
BTL (Electric)											
GRLF	18.8	$1,094,660	$0	$0	$1,094,660	$1,094,660	$1,094,660	$0	$0	$0	$0
Mersey Additional Energy	178.9	$10,282,532	$0	$419,451	$10,701,983	$10,572,961	$10,572,961	$0	$0	$0	$0
LRT	322.1	$21,183,202	$879,406	$1,219,578	$23,282,186	$22,513,775	$22,513,775	$0	$0	$0	$0
Bowater Mersey	189.0	$9,934,827	$0	$0	$9,934,827	$9,934,827	$9,934,827	$0	$0	$0	$0
Total BTL (Electric) Classes	**708.8**	**$42,495,221**	**$879,406**	**$1,639,029**	**$45,013,656**	**$44,116,223**	**$44,116,223**	**$0**	**$0**	**$0**	**$0**
LED SL Capital Costs**		$1,565,170	$0	$0	$1,565,170	$1,962,839	$1,612,125	$350,714	$0	$42,134	$392,848
In Province Total	**10,020.3**	**$1,168,875,912**	**$34,342,042**	**$33,856,395**	**$1,237,074,349**	**$1,327,787,711**	**$1,271,945,801**	**$55,841,910**	**$0**	**$6,537,278**	**$62,550,648**
Export	28.9	$1,806,823	$0	$0	$1,806,823	$1,806,823	$1,806,823	$0	$0	$0	$0
Total Electric Sales	**10,049.2**	**$1,170,682,735**	**$34,342,042**	**$33,856,395**	**$1,238,881,172**	**$1,329,594,534**	**$1,273,752,624**	**$55,841,910**	**$0**	**$6,537,278**	**$62,550,648**
Misc Revenue	701.7	$21,959,249	$0	$0	$21,959,249	$22,582,498	$22,315,097	$267,401	$0	$31,313	$298,714
Grand Total	**10,750.9**	**$1,192,641,983**	**$34,342,042**	**$33,856,395**	**$1,260,840,421**	**$1,352,177,033**	**$1,296,067,721**	**$56,109,311**	**$0**	**$6,568,590**	**$62,849,362**

* The figures for LRT have been adjusted to reflect the correct load
**LED Capital Costs will be updated at the time of the capital work order

2014 REVENUE INCREASE DEFERRAL UNDER RATE STABILIZATION PLAN

Rate Classes	2014 Proposed Revenues With Riders Before Rate Stabilization	2014 Proposed Revenues With Riders After Rate Stabilization	Revenue Increase Deferral by Rate Class by the end of 2014					
Columns	L	M	N	O	P	Q	R	S
	Amount	Amount	2014 Deferred Amount	Fixed Cost Contribution from the NPPH Mill	Interest	2014 Total	2013 Deferred Amount	Total Deferred Amount
ATL								
Residential	**$689,767,669**	**$653,998,267**	**$35,769,402**	**$0**	**$1,400,372**	**$37,169,774**	**$34,887,552**	**$72,057,326**
Small General	$36,687,017	$34,825,489	$1,861,528	$0	$72,879	$1,934,406	$1,874,887	$3,809,294
General Demand	$321,964,307	$309,954,678	$12,009,629	$0	$470,177	$12,479,806	$13,638,909	$26,118,715
Large General	$43,662,457	$42,344,632	$1,317,826	$0	$51,593	$1,369,419	$1,889,165	$3,258,584
Total Commercial	**$402,313,781**	**$387,124,799**	**$15,188,982**	**$0**	**$594,649**	**$15,783,631**	**$17,402,962**	**$33,186,592**
Small Industrial	$33,494,503	$32,037,181	$1,457,322	$0	$57,054	$1,514,376	$1,670,126	$3,184,503
Medium Industrial	$57,292,737	$55,115,575	$2,177,162	$0	$85,236	$2,262,398	$2,605,578	$4,867,976
Large Industrial - Firm	*$21,922,990*	*$21,434,038*	*$488,952*	*$0*	*$19,142*	*$508,095*	*$819,864*	*$1,327,958*
Large Industrial - Interruptible	*$64,921,418*	*$63,349,834*	*$1,571,584*	*$0*	*$61,528*	*$1,633,111*	*$2,677,053*	*$4,310,164*
Total Large Industrial	$86,844,408	$84,783,872	*$2,060,536*	*$0*	*$80,670*	*$2,141,206*	*$3,496,916*	*$5,638,122*
ELI 2PT - RTP*	$0	$0	$0	$0	$0	$0	$0	$0
Total Industrial	**$177,631,648**	**$171,936,627**	**$5,695,020**	**$0**	**$222,960**	**$5,917,980**	**$7,772,621**	**$13,690,601**
Municipal	$21,482,620	$20,863,552	$619,069	$0	$24,237	$643,305	$731,727	$1,375,032
Unmetered	$23,989,269	$23,014,246	$975,023	$0	$38,172	$1,013,195	$1,362,939	$2,376,134
Total Other	**$45,471,889**	**$43,877,798**	**$1,594,091**	**$0**	**$62,409**	**$1,656,500**	**$2,094,666**	**$3,751,166**
Total ATL Classes	**$1,315,184,988**	**$1,256,937,492**	**$58,247,496**	**$0**	**$2,280,389**	**$60,527,885**	**$62,157,800**	**$122,685,686**
BTL (Electric)								
GRLF	$1,071,642	$1,071,642	$0	$0	$0	$0	$0	$0
Mersey Additional Energy	$10,241,381	$10,241,381	$0	$0	$0	$0	$0	$0
LRT	$21,856,349	$21,856,349	$0	$0	$0	$0	$0	$0
Bowater Mersey	$9,782,311	$9,782,311	$0	$0	$0	$0	$0	$0
Total BTL (Electric) Classes	**$42,951,683**	**$42,951,683**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
LED SL Capital Costs**	$4,340,815	$3,603,688	$737,128	$0	$28,859	$765,986	$392,848	$1,158,834
In Province Total	**$1,362,477,486**	**$1,303,492,862**	**$58,984,623**	**$0**	**$2,309,248**	**$61,293,871**	**$62,550,648**	**$123,844,519**
Export	$1,943,419	$1,943,419	$0	$0	$0	$0	$0	$0
Total Electric Sales	**$1,364,420,905**	**$1,305,436,281**	**$58,984,623**	**$0**	**$2,309,248**	**$61,293,871**	**$62,550,648**	**$123,844,519**
Misc Revenue	$23,479,095	$23,190,143	$288,953	$0	$11,312	$300,265	$298,714	$598,979
Grand Total	**$1,387,900,000**	**$1,328,626,424**	**$59,273,576**	**$0**	**$2,320,561**	**$61,594,136**	**$62,849,362**	**$124,443,498**

**LED Capital Costs will be updated at the time of the capital work order

Street / Crosswalk Lighting Study

2013 Schedules - Rate Stabilization

SCHEDULE 1

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of MARCH 2011

		MARCH 2011 Adjusted (Quantity)				FORECAST 2013 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
001/003	Incandescent < 300 Watts	27	0	7	34	27	0	7	34	27
002	Incandescent > 300 Watts	2	0	0	2	2	0	0	2	2
		29	0	7	36	29	0	7	36	29
100	Mercury Vapour 100 Watts	251	0	0	251	251	0	0	251	234
101/201/301	Mercury Vapour 125 Watts	10,349	7	11	10,367	10349	7	11	10367	9635
102/202/302	Mercury Vapour 175 Watts	2,474	21	157	2,652	2474	21	157	2652	2303
103/203/303	Mercury Vapour 250 Watts	953	35	54	1,042	953	35	54	1042	887
104/204/304	Mercury Vapour 400 Watts	926	9	15	950	926	9	15	950	862
105/205/305	Mercury Vapour 700 Watts	11	0	1	12	11	0	1	12	11
106/206/306	Mercury Vapour 1000 Watts	86	22	7	115	86	22	7	115	86
107	Mercury Vapour 250 Watt Cont. Oper.	3	0	0	3	3	0	0	3	3
		15,053	94	245	15,392	15053	94	245	15392	14021
110	Fluorescent 2x24" 70 Watts	897	0	0	897	897	0	0	897	897
111	Fluorescent 2x48" 220 Watts	114	0	0	114	114	0	0	114	114
112	Fluorescent 2x72" 300 Watts	67	0	0	67	67	0	0	67	67
113/213	Fluorescent 4x72" 600 Watts	15	0	0	15	15	0	0	15	15
114/214	Fluorescent 1x96" 110 Watts	5	26	0	31	5	26	0	31	5
115/215	Fluorescent 1x72" 150 Watts	1	3	0	4	1	3	0	4	1
116	Fluorescent 4x48" 440 Watts	2	0	0	2	2	0	0	2	2
217	Fluorescent 1x48"	0	1	0	1	0	1	0	1	0
218	Fluorescent 2x48"	0	0	0	0	0	0	0	0	0
330	Fluorescent 4x35"	0	0	2	2	0	0	2	2	0
350	Fluorescent 4x96"	0	0	76	76	0	0	76	76	0
		1,101	30	78	1,209	1101	30	78	1209	1,101
117	Fluorescent Crosswalk Cont. 4x72"	0	0	1	1	0	0	1	1	0
118	Fluorescent Crosswalk Cont. 2x24"	0	0	17	17	0	0	17	17	0
119	Fluorescent Crosswalk Cont. 4x48"	0	0	23	23	0	0	23	23	0
120	Fluorescent Crosswalk Cont. 2x96"	0	0	30	30	0	0	30	30	0
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21	0	0	21	21	0
		0	0	92	92	0	0	92	92	0
310	Fluorescent Crosswalk 2x24"	0	0	2	2	0	0	2	2	0
311	Fluorescent Crosswalk 4x48"	0	0	5	5	0	0	5	5	0
312	Fluorescent Crosswalk 2x72"	0	0	1	1	0	0	1	1	0
313	Fluorescent Crosswalk 4x72"	0	0	0	0	0	0	0	0	0
314	Fluorescent Crosswalk 1x96"	0	0	25	25	0	0	25	25	0
315	Fluorescent Crosswalk 1x72"	0	0	0	0	0	0	0	0	0
		0	0	33	33	0	0	33	33	0

SCHEDULE 1

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of MARCH 2011

		MARCH 2011 Adjusted (Quantity)				FORECAST 2013 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
121/221/321	High Pressure Sodium 250 Watts	4,317	171	964	5,452	4317	171	964	5452	4,019
122/326	High Pressure Sodium 400 Watts	2,910	0	89	2,999	2910	0	89	2999	2,709
123/222/322	High Pressure Sodium 70 Watts	35,979	258	5,978	42,215	35979	258	5978	42215	33,496
124/223/323	High Pressure Sodium 100 Watts	43,398	135	2,377	45,910	43398	135	2377	45910	40,402
125/224/324	High Pressure Sodium 150 Watts	5,241	230	125	5,596	5241	230	125	5596	4,879
126	HP Sodium 100 Watts - Cont. Oper.	15	0	0	15	15	0	0	15	15
327	High Pressure Sodium 500 Watts	0	0	3	3	0	0	3	3	0
328	High Pressure Sodium 1000 Watts	0	0	14	14	0	0	14	14	0
329	High Pressure Sodium 1500 Watts	0	0	1	1	0	0	1	1	0
		91,860	794	9,551	102,205	91860	794	9551	102205	85,520
130	Low Pressure Sodium 135 Watts	53	0	0	53	53	0	0	53	49
131/231/331	Low Pressure Sodium 180 Watts	485	39	37	561	485	39	37	561	452
132	Low Pressure Sodium 90 Watts	0	0	0	0	0	0	0	0	0
		538	39	37	614	538	39	37	614	501
140/342	Metallic Arc 400 Watts	1,213	0	159	1,372	1213	0	159	1372	1,129
141/341	Metallic Arc 1000 Watts	981	0	22	1,003	981	0	22	1003	981
142/343	Metallic Arc 250 Watts	100	0	84	184	100	0	84	184	93
143	Metallic Arc 150 Watts	4	0	0	4	4	0	0	4	4
144	Metallic Arc 100 Watts	7	0	0	7	7	0	0	7	7
344	Metallic Arc 175 Watts	0	0	112	112	0	0	112	112	0
345	Metallic Arc 150 Watts	0	0	20	20	0	0	20	20	0
346	Metallic Arc 100 Watts	0	0	0	0	0	0	0	0	0
		2,305	0	397	2,702	2305	0	397	2702	2,214
532/538	LED 44 Watts	0	0	1,732	1,732	0	0	1732	1732	0
539	LED 110 Watts	0	0	2,609	2,609	0	0	2609	2609	0
533	LED 66 Watts	0	0	138	138	0	0	138	138	0
534	LED 88 Watts	0	0	513	513	0	0	513	513	0
537	LED 173 Watts	0	0	38	38	0	0	38	38	0
540	LED 65 Watts	0	0	464	464	0	0	464	464	0
541	LED 55 Watts	0	0	736	736	0	0	736	736	0
542	LED 83 Watts	0	0	1,039	1,039	0	0	1039	1039	0
543	LED 48 Watts	0	0	72	72	0	0	72	72	0
544	LED 72 Watts	0	0	308	308	0	0	308	308	0
	Total	0	0	7,649	7,649	0	0	7649	7649	0
	LED A	7801	0	0	7801	7801	0	0	7801	14,187
	LED B	989	0	0	989	989	0	0	989	1,798
	LED C	373	0	0	373	373	0	0	373	678
	Total	9163	0	0	9163	9163	0	0	9163	16,663
	Total	**120,049**	**957**	**18,089**	**139,095**	**120,049**	**957**	**18,089**	**139,095**	**120,049**

SCHEDULE 2

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY
CALCULATION OF MAINTENANCE COSTS BY FIXTURE TYPE

(A) Code	(B) Lamp Type	(C) Service Life (Years)	(D) Maintenance Weighting Factors	(E) # of Full Chg & Eng.+Maint. Fixtures	(F) Weighting Total	(G) Cost Per Year	(H) Cost Per Month
A	Mercury Vapour	6.000	1.0000	4,502	4,502	$48.45	$4.04
B	Mercury Vapour - 125W	4.500	1.3333	9,642	12,856	$64.60	$5.38
C	Fluorescent	3.000	2.0000	1,131	2,262	$96.89	$8.07
D	High Pressure Sodium (Note1)	6.000	1.0000	86,329	86,329	$48.45	$4.04
E	Metallic Arc 100W, 150W & 250W	2.500	2.4000	103	248	$116.27	$9.69
F	Metallic Arc 400W	3.750	1.6000	1,129	1,807	$77.51	$6.46
G	Metallic Arc 1000W	2.500	2.4000	981	2,354	$116.27	$9.69
H	Low Pressure Sodium	2.000	3.0000	540	1,620	$145.34	$12.11
I	LED	20.000	0.3000	0	0	$14.53	$1.21
				104,358	111,978		

Street Lighting Maint. Expenses
(from 2013 COSS, Exhibit 6A) **$5,424,988**

Annual Cost of High Pressure Sodium
($5,424,987.99 / 111978.336007024 weighted fixtures) **$48.45**

Note 1: Maintenance weighting factors relative to High Pressure Sodium fixture, index = 1.0
Factor is: HPS service life / various fixture service lives

SCHEDULE 3

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

Gross Plant Value (including installation costs) less Retirements of Non-LED Street Lighting Equipment, 2013 Average	----------→	**Total** **$43,821,074**

Description	Unit Cost Mar/1977	Unit Cost Mar-11	Historical 11-Mar Fixtures	Average # of Fixtures bfr LED	Average # of Fixtures aft LED	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	27	27	27	$1,733	
Incandescent > 300 Watts	$63.62	$79.53	2	2	2	$159	
Mercury Vapour 100 Watts	$76.55	$229.55	251	251	234	$57,616	
Mercury Vapour 125 Watts	$77.16	$204.78	10,349	10,349	9,635	$2,119,288	
Mercury Vapour 175 Watts	$85.30	$201.27	2,474	2,474	2,303	$497,946	
Mercury Vapour 250 Watts	$87.24	$291.38	953	953	887	$277,681	
Mercury Vapour 400 Watts	$107.82	$301.45	926	926	862	$279,143	
Mercury Vapour 700 Watts	$485.12	$449.78	11	11	11	$4,948	
Mercury Vapour 1000 Watts	$492.29	$579.25	86	86	86	$49,816	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$291.38	3	3	3	$874	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	897	897	897	$119,346	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	114	114	114	$18,797	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	67	67	$14,968	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	15	15	$5,507	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	5	5	$1,000	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	1	1	1	$152	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	2	2	$472	
High Pressure Sodium 70 Watts	***N/A***	$207.51	35,979	35,979	33,496	$7,465,995	
High Pressure Sodium 100 Watts	***N/A***	$210.65	43,413	43,413	40,417	$9,144,775	
High Pressure Sodium 150 Watts	***N/A***	$232.66	5,241	5,241	4,879	$1,219,396	
High Pressure Sodium 250 Watts	$156.49	$231.67	4,317	4,317	4,019	$1,000,140	
High Pressure Sodium 400 Watts	$173.73	$246.21	2,910	2,910	2,709	$716,479	
High Pressure Sodium 1000 Watts	***N/A***	$615.53	0	0	0	$0	
Low Pressure Sodium 90 Watts	***N/A***	$554.53	0	0	0	$0	
Low Pressure Sodium 135 Watts	$371.69	$554.53	53	53	49	$29,390	
Low Pressure Sodium 180 Watts	$226.10	$880.14	485	485	452	$426,867	
Metallic Additive 250 Watts	***N/A***	$298.33	104	104	97	$31,026	
Metallic Additive 400 Watts	$358.84	$305.76	1,213	1,213	1,129	$370,885	
Metallic Additive 1000 Watts	$560.49	$526.16	981	981	981	$516,159	
Metallic Additive 100 Watts	***N/A***		7	7	7	$0	
			110,886	110,886	103,386		**24,370,558**
							$19,450,516
							$188.13
Total # of light types being displaced by LED			108,675	108,675	101,175		
Total Installation Costs (Labour)							
Installation Costs per Fixture							

Escalation Factor (Incandescent)	125%
Escalation Factor (Fluorescent)	125%

Note: 2007 costs are based on stores material inventory cost as of June 2007 with the exception of Incandescent and fluorescent which have been assumed at 130% of 1977 costs.

Sample Material Cost - 100 Watt High Intensity (Pressure) Sodium :
Inventory Prices as of March 2011

Fixture, Ballast & Photocell	$124.02
Bracket Assembly (Davit)	67.32
Wire	16.71
Miscellaneous Hardware	2.60
Lamp Replacement	8.62
TOTAL	**$219.27**

SCHEDULE 4

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

	Non Led	LED
Depreciation Rate for 2013	5.33%	5.33%
# of Years	18.76	18.76
Tax Adjusted Weighted Average Cost of Capital	10.40%	9.31%
Pre-tax WACC	7.76%	7.76%
Tax-related Gross-up Depreciation factor	31.00%	31.00%
Salvage Rate (% of Depreciation)	0.00%	0.00%
Salvage Rate incl in Depr. Rate for 2013	0.00%	0.00%
# of Years	N/A	N/A

	Revenue Correction factor Non LED	LED
Simulated at current meth.	$7,646,756	$1,905,943
Total cost per COSS (and adjusted for energy)	$3,708,001	$1,612,125
Revenue Correction Factor	**0.4849**	**0.8458**

				Before Correction Factor				Correction Factor	Aligned with COSS results		2013 Forecast					
	Material Cost January 2010	Labour Cost	Total	Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost		Total Annual Cost	Monthly Cost	# of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Incandescent < 300 Watts	$64.20	188.13	$252.33	$19.49	$26.24	$0.00	$45.73	0.485	$22.18	$1.85	27	526.28	708.56		1,234.84	598.79
Incandescent > 300 Watts	79.53	188.13	267.66	$20.68	$27.84	$0.00	48.51	0.485	$23.52	1.96	2	41.35	55.67		97.02	47.05
Mercury Vapour 100 Watts	229.55	188.13	417.68	$32.26	$43.44	$0.00	75.70	0.485	$36.71	3.06	234	7,539.48	10,150.72		17,690.20	8,578.18
Mercury Vapour 125 Watts	204.78	188.13	392.92	$30.35	$40.86	$0.00	71.21	0.485	$34.53	2.88	9,635	292,429.19	393,709.55		686,138.74	332,716.69
Mercury Vapour 175 Watts	201.27	188.13	389.41	$30.08	$40.50	$0.00	70.58	0.485	$34.22	2.85	2,303	69,282.67	93,278.13		162,560.81	78,827.63
Mercury Vapour 250 Watts	291.38	188.13	479.51	$37.04	$49.87	$0.00	86.91	0.485	$42.14	3.51	887	32,863.40	44,245.36		77,108.76	37,390.94
Mercury Vapour 400 Watts	301.45	188.13	489.58	$37.82	$50.92	$0.00	88.74	0.485	$43.03	3.59	862	32,603.24	43,895.09		76,498.33	37,094.93
Mercury Vapour 700 Watts	449.78	188.13	637.92	$49.28	$66.34	$0.00	115.62	0.485	$56.07	4.67	11	542.04	729.78		1,271.82	616.72
Mercury Vapour 1000 Watts	579.25	188.13	767.39	$59.28	$79.81	$0.00	139.09	0.485	$67.44	5.62	86	5,097.90	6,863.52		11,961.42	5,800.23
Mercury Vapour 250 Watt Cont. Oper.	291.38	188.13	479.51	$37.04	$49.87	$0.00	86.91	0.485	$42.14	3.51	3	111.12	149.61		260.73	126.43
Fluorescent 2x24" 70 Watts	133.05	188.13	321.18	$24.81	$33.40	$0.00	58.21	0.485	$28.23	2.35	897	22,254.90	29,962.70		52,217.60	25,320.92
Fluorescent 2x48" 220 Watts	164.89	188.13	353.02	$27.27	$36.71	$0.00	63.98	0.485	$31.03	2.59	114	3,108.75	4,185.43		7,294.18	3,537.03
Fluorescent 2x72" 300 Watts	223.40	188.13	411.53	$31.79	$42.80	$0.00	74.59	0.485	$36.17	3.01	67	2,129.90	2,867.58		4,997.48	2,423.33
Fluorescent 4x72" 600 Watts	367.15	188.13	555.28	$42.89	$57.75	$0.00	100.64	0.485	$48.80	4.07	15	643.41	866.24		1,509.65	732.05
Fluorescent 1x96" 110 Watts	200.00	188.13	388.13	$29.98	$40.37	$0.00	70.35	0.485	$34.11	2.84	5	149.91	201.83		351.74	170.56
Fluorescent 1x72" 150 Watts	151.53	188.13	339.66	$26.24	$35.32	$0.00	61.56	0.485	$29.85	2.49	1	26.24	35.32		61.56	29.85
Fluorescent 4x48" 440 Watts	236.14	188.13	424.27	$32.77	$44.12	$0.00	76.90	0.485	$37.29	3.11	2	65.55	88.25		153.80	74.58
High Pressure Sodium 70 Watts	207.51	188.13	395.64	$30.56	$41.15	$0.00	71.71	0.485	$34.77	2.90	33,496	1,023,708.19	1,378,260.79		2,401,968.98	1,164,742.81
High Pressure Sodium 100 Watts	210.65	188.13	398.78	$30.80	$41.47	$0.00	72.28	0.485	$35.05	2.92	40,417	1,245,018.73	1,676,220.34		2,921,239.08	1,416,542.94
High Pressure Sodium 150 Watts	232.66	188.13	420.80	$32.51	$43.76	$0.00	76.27	0.485	$36.98	3.08	4,879	158,602.93	213,533.71		372,136.64	180,453.40
High Pressure Sodium 250 Watts	231.67	188.13	419.81	$32.43	$43.66	$0.00	76.09	0.485	$36.90	3.07	4,019	130,333.56	175,473.48		305,807.04	148,289.40
High Pressure Sodium 400 Watts	246.21	188.13	434.35	$33.55	$45.17	$0.00	78.72	0.485	$38.17	3.18	2,709	90,897.55	122,379.13		213,276.68	103,420.35
High Pressure Sodium 1000 Watts	615.53	188.13	803.67	$62.08	$83.58	$0.00	145.66	0.485	$70.63	5.89	-	-	-		-	-
Low Pressure Sodium 90 Watts	554.53	188.13	742.67	$57.37	$77.24	$0.00	134.61	0.485	$65.27	5.44	-	-	-		-	-
Low Pressure Sodium 135 Watts	554.53	188.13	742.67	$57.37	$77.24	$0.00	134.61	0.485	$65.27	5.44	49	2,830.68	3,811.06		6,641.74	3,220.66
Low Pressure Sodium 180 Watts	880.14	188.13	1,068.27	$82.52	$111.10	$0.00	193.62	0.485	$93.89	7.82	452	37,260.27	50,165.05		87,425.31	42,393.56
Metallic Arc 250 Watts	298.33	188.13	486.46	$37.58	$50.59	$0.00	88.17	0.485	$42.75	3.56	97	3,638.35	4,898.46		8,536.80	4,139.60
Metallic Arc 400 Watts	305.76	188.13	493.89	$38.15	$51.36	$0.00	89.52	0.485	$43.41	3.62	1,129	43,083.98	58,005.75		101,089.74	49,019.59
Metallic Arc 1000 Watts	$526.16	188.13	$714.29	$55.18	$74.29	$0.00	$129.46	0.485	$62.78	$5.23	981	54,128.04	72,874.82		127,002.86	61,585.17
Metallic Additive 100 Watts	$0.00	188.13	$188.13	$14.53	$19.57	$0.00	$34.10	0.485	$16.53	$1.38	7	94.71	127.51		222.22	107.76
Total											**103,386**	**$3,259,012**	**$4,387,743**		**$7,646,756**	**$3,708,001**

				Before Correction Factor				Correction Factor	Aligned with COSS results		2013 Forecast					
	Material Cost January 2010	Labour Cost	Total	Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost		Total Annual Cost	Monthly Cost	# of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
LED A	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	0.846	$96.75	8.06	14,187	816,878.94	984,530.70	(178,682.77)	1,622,726.86	1,372,569.39
LED B	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	0.846	$96.75	8.06	1,798	103,538.14	124,787.75	(22,647.77)	205,678.13	173,971.05
LED C	$420.00	$325.40	$745.40	$57.58	$69.40	-$12.59	114.38	0.846	$96.75	8.06	678	39,032.37	47,043.16	(8,537.88)	77,537.66	65,584.55
											16,663	**$959,449**	**$1,156,362**	**-$209,868**	**$1,905,943**	**$1,612,125**

SCHEDULE 5

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Rate by Components For 2013 Street Light Rates

	Proportion	Cost	Extended	Non-LED	Extended	LED
a) Weighted Average Cost of Capital - Pretax						
ST Debt	6.3%	4.1%	0.3%	0.26%	0.3%	0.26%
LT Debt	52.5%	7.3%	3.8%	3.83%	3.8%	3.83%
Preferred	3.7%	6.0%	0.2%	0.22%	0.2%	0.22%
Common	37.5%	9.2%	3.5%	3.45%	3.5%	3.45%
	100.0%		7.8%		7.8%	
WACC - pretax cost				7.76%		7.76%
b) Additional income tax for common equity						
Extended equity cost			3.45%		3.45%	
Effective tax rate (excluding surtax)			31.0%		31.0%	
Income tax			1.55%		1.55%	
WACC - equity tax cost				1.55%		1.55%
c) Large Corporations Tax						
Provincial capital tax (2013)			0.000%		0.000%	
Federal capital tax (2013)			0.000%		0.000%	
Ave. NBV - Street Lighting			$15.949		$8.148	
Ave. NBV - Assigned GP Plt.			1.239		0.633	
Ave. Deferred Chgs & W/C			1.530		0.782	
NPV - Total Street Lighting			$18.718		$9.563	
Provincial capital tax			$0.000		$0.000	
Federal capital tax			$0.000		$0.000	
Total			$0.000		$0.000	
Percentage of NBV			0.00%		0.00%	
WACC - Large Corporations Tax				0.00%		0.00%
d) Grants in Lieu of Property Tax						
Total 2013 Forecasted Expense			$37.500		N/A	
St. Lgts. % of Total Electric Plant			0.55%		N/A	
St. Lgts. Allocated Amount			$0.205		N/A	
Percentage of NBV			1.09%		N/A	
WACC - Grants in Lieu of Property Tax				1.09%		0.00%
Total WACC - Interest / Carrying Cost				**10.40%**		**9.31%**

SCHEDULE 5A

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components

For 2013 Street Light Rates

Depreciation Rate	**5.33%**
Salvage Rate	**0.00%**
Salvage Incl. in Depreciation Rate	**0.00%**
Gross-up factor for tax purposes (LED only)	**31.00%**

		Non LED	Non LED	LED	LED Deferral
Gross Plant Value (YA)			$43,821	$11,334	
Net Plant Value (YA)			$15,949	$11,020	$2,606
a) Weighted Average Cost of Capital - Pretax					
	ST Debt	0.26%		28	7
	LT Debt	3.83%		422	100
	Subtotal		*589*	*451*	*107*
	Preferred	0.22%	$35.7	25	6
	Common	3.45%	$534.9	380	90
	WACC - pretax cost	7.76%	$1,159.2	$855	$202
b) Additional income tax for common equity					
	WACC - equity tax cost	1.55%		171	40
c) Large Corporations Tax					
	WACC - Large Corporations Tax	0.00%		0	0
Subtotal			*$233.4*	*171*	*40*
d) Grants in Lieu of Property Tax					
	WACC - Grants in Lieu of Property Tax	1.09%	$164.2	0	28
Subtotal Financing Expense		**10.40%**	**$1,556.8**	**$1,026.1**	**$271.0**
Depreciation Expense			**$2,342.2**	**$604.121**	**$0.0**
Gross up for Tax Purposes				**$271.4**	**$0.0**
Total Depreciation Expense including Gross up for Tax Purposes			**$2,342.2**	**$875.5**	**$0.0**
CCA			**$0.0**	**-$209.9**	
TOTAL CAPITAL COST EXPENSE			**$3,708.0**	**$1,691.8**	**$271.025**

SCHEDULE 6

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY
AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

Light Type Street Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Incandescent < 300 Watts	$51.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Incandescent > 300 Watts	$63.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mercury Vapour 100 Watts	$229.55	$122.41	$15.99	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 125 Watts	$204.78	$102.95	$10.68	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 175 Watts	$201.27	$102.95	$7.17	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 250 Watts	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 400 Watts	$301.45	$198.75	$8.98	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 700 Watts	$449.78	$318.97	$37.10	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 1000 Watts	$579.25	$439.19	$46.35	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 250 Watt Cont. Oper.	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Fluorescent 2x24" 70 Watts	$106.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x48" 220 Watts	$131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x72" 300 Watts	$178.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x72" 600 Watts	$293.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x96" 110 Watts	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x72" 150 Watts	$121.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x48" 440 Watts	$188.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High Pressure Sodium 70W	$207.51	$120.88	$8.81	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 100W	$210.65	$124.02	$8.62	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 150W	$232.66	$146.03	$8.67	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 250 Watts	$231.67	$142.48	$10.59	$4.52	$69.88	$16.71	$1.09	$1.51
High Pressure Sodium 400 Watts	$246.21	$157.02	$13.19	$4.52	$69.88	$16.71	$1.09	$1.51
Low Pressure Sodium 90W	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 135 Watts	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 180 Watts	$880.14	$788.99	$54.77	$4.52	$67.32	$16.71	$1.09	$1.51
Metallic Additive 250W	$298.33	$190.30	$18.83	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 400 Watts	$305.76	$201.63	$14.93	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 1000 Watts	$526.16	$405.65	$31.31	$0.00	$69.88	$16.71	$1.09	$1.51
LED A	$420.00							
LED B	$420.00							
LED C	$420.00							

Light Type Flood Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Mercury Vapour 175 Watts	$67.32	$53.03	$7.17	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 250 Watts	$412.88	$397.90	$7.86	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 400 Watts	$297.27	$281.17	$8.98	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 1000 Watts	$507.90	$439.19	$46.35	$19.77	$0.00	$0.00	$1.09	$1.51
HIS 150W	$215.75	$183.39	$25.23	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 250 Watts	$202.12	$184.41	$10.59	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 400 Watts	$215.26	$194.95	$13.19	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Additive 250W	$216.25	$190.30	$18.83	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 400 Watts	$223.69	$201.63	$14.93	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 1000 Watts	$459.33	$405.65	$31.31	$19.77	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 70W HPS	$197.77	$195.17	$8.81	$4.52	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 100W HPS	$143.10	$140.50	$8.62	$4.52	$0.00	$0.00	$1.09	$1.51

SCHEDULE 7

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0000386440	LAMP FLUORESCENT 40W 48	1.35	
0000386450	LAMP FLUORESCENT 40W 48	1.36	
0000386700	LAMP FLUORESCENT 75W 96	3.49	
0000386710	LAMP FLUORESCENT 205W	3.95	
0000387070	LAMP FLUORESCENT 35W 24	4.19	
0000387190	LAMP FLUORESCENT 60W 48	3.19	
0000387360	LAMP FLUORESCENT 85W 72	6.54	
0000388000	LAMP 100 WATT M.V.	15.99	
0000388180	LAMP 125 WATT M.V.	10.68	
0000388330	LAMP 175 WATT M.V.	7.17	
0000388500	LAMP 250 WATT M.V.	7.86	
0000388660	LAMP 400 WATT M.V.	8.98	
0000388770	LAMP 700 WATT M.V.	37.10	
0000388980	LAMP 1000 WATT MV	46.35	
0000388990	LAMP 70 WATT H.P.S.	8.81	
0000389000	LAMP 100 WATT H.P.S.	8.62	
0000389030	LAMP 135 WATT L.P.S.	44.00	
0000389040	LAMP 150 WATT HPS 100V	25.23	
0000389060	LAMP 150 WATT H.P.S.55V	8.67	
0000389090	LAMP 180 WATT L.P.S.	54.77	
0000389250	LAMP 250 WATT H.P.S.	10.59	
0000389400	LAMP 400 WATT H.P.S.	13.19	
0000389450	LAMP 1000W HPS	60.32	
0000389700	LAMP HALIDE 250W	18.83	
0000389770	LAMP HALIDE 400W	14.93	
0000389810	LAMP HALIDE 1000W	31.31	
0000389900	LAMP STREET LITE SIGNAL	2.21	
0002103270	CONDUIT FLEX BLK 1/2"	4.36	
0050091540	BOLT LAG 1/2"X 4" GALV	0.46	
0050103120	BOLT MACHINE 5/8" X 12"	1.05	
0054223510	CRIMPIT #2/0- #8 WR139	0.55	
0057151000	BRACKET 10'L	101.45	
0057152040	BRACKET 1 1/4"X4' FIXED	60.02	
0057152220	BRACKET 4'X 2' 16" TEN	27.46	
0057154060	BRACKET 1 1/4"X6' LOWER	67.32	
0057155060	BRACKET SWIVEL 1 1/4 X6	18.91	
0057155720	BRACKET TAPERED 6' X 2"	48.90	
0057155723	BRACKET TAPERED 8'	87.05	
0057155725	BRACKET TAPERED 2"X10'	106.44	
0057156020	BRACKET LOWER 2" X 6'	69.88	
0057156080	BRACKET FIXED 2" X 8'	87.48	
0057157010	BRACKET TAPERED 12'L	173.80	
0057158140	PLATE POLE ST LITE 1 1/	9.46	
0057158220	PLATE POLE ST LIGHT 2"	26.24	

SCHEDULE 7

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057350350	LUMINAIRE LPS 135W	463.38	
0057350720	LUM LPS 180W 120/240/347 V	788.99	R04B
0057350750	LUMINAIRE LPS 180W 240V	493.30	XX
0057350800	LUMINAIRE LPS 180W 347V	780.20	XX
0057350830	LUMINAIRE HPS 70W POLY	73.33	XX
0057350835	LUM. 70W POLY C/W LAMP	99.23	XX
0057350836	LUM 70W POLY ALUM.ALLOY	97.70	XX
0057350837	LUMINAIRE 70W HPS CWA ACRYLIC	120.88	C01A
0057350850	LUMINAIRE HPS 70W GLASS	69.32	XX
0057350855	LUM. 70W GLASS C/W LAMP	97.68	C03A
0057350856	LUM 70W GLASS AL. ALLOY	99.37	M12D
0057350857	LUM. 70W GLASS CWI BAL.	120.32	M08A
0057350860	LUM 100W HPS POLY	75.00	XX
0057350865	LUM. 100W POLY C/W LAMP	100.21	XX
0057350866	LUMINAIRE 100W ACRYLIC HPS CWA	124.02	C07A
0057350867	LUM 100W POLY AL. ALLOY	98.37	XX
0057350875	LUM. 100W GLASS C/WLAMP	98.76	XX
0057350877	LUM. 100W GLASS CWI BAL	135.75	XX
0057350880	LUMINAIRE HPS 150W GLAS	82.27	XX
0057350885	LUM. 150W GLASS C/WLAMP	100.95	XX
0057350886	LUMINAIRE 150W HPS CWI GLASS	146.03	M05A
0057350887	LUM. 150W HPS 240V GLAS	150.88	C09A
0057350890	LUMINAIRE HPS 150W POLY	79.24	XX
0057350895	LUM. 150W POLY C/W LAMP	102.95	XX
0057351315	LUMINAIRE 250W HPS CWI GLASS	142.48	C07A
0057351400	LUMINAIRE 250W HPS CWI 347V	160.68	C05A
0057351710	LUMINAIRE HPS 400W GLAS	109.60	XX
0057351715	LUMINAIRE 400W HPS CWI 120/240	157.02	M12A
0057351720	LUMINAIRE HPS 400W 240V	204.30	XX
0057351730	LUMINAIRE HPS 400W 347V	196.00	XX
0057351760	LUMINAIRE 400W 600V HPS CWI GL	172.33	M12A
0057353330	LUMINAIRE MTL-HLDE 400W	281.54	XX
0057353500	LUMINAIRE HALIDE 1000 W	300.00	XX
0057353550	LUMINAIRE HALIDE 1000 W	294.79	T01C
0057400920	AREA LIGHT MV 125 W	107.76	XX
0057401200	LUMINAIRES 70W H-P.S.	107.80	D14B
0057401205	DUSK-T-DAWN 70W HPS CWA	195.17	D08B
0057402020	AREA LIGHT MV 175 W	92.88	XX
0057402100	LUMINAIRES 100W H.P.S.	106.37	XX
0057402105	DUSK-T-DAWN 100W HPS CWA	140.50	C15A
0057402150	FLOODLIGHT 150W HPS CWI	183.39	C17A
0057402240	FLOODLIGHT M.V. 175W	53.03	
0057403330	FLOODLIGHT M V 250 W	397.90	XX
0057403500	FLOODLIGHT 250W HPS CWI	184.41	

SCHEDULE 7

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057404050	FLOODLIGHT M V 400 W	281.17	XX
0057404600	FLOODLIGHT 400W HPS CWI	194.95	C11A
0057408250	FLOODLIGHT MTL HAL.250W	190.30	D05B
0057408500	FLOODLIGHT 400W MTL-HAL CWI	201.63	D03A
0057409000	FLOODLIGHT 1000W MH CWI	405.65	
0057409380	FLOODLIGHT M V 1000 W	439.19	XX
0057600450	BRACKET & ADAPTORS	9.40	
0057601010	CAP SHORTING TWIST LOCK	4.87	
0057601200	CONTROL 120 V PHOTO	7.05	
0057601400	CONTROL ELECT 120V PHOTOCELL	4.52	
0057602000	PHOTO CONTROL 120V HD	19.77	
0057602400	CONTROL 240V ELECT PHOTOCELL	10.96	
0057602960	GUARD WIRE FOR ST-LITE	50.44	
0057603800	REFRACTOR GLASS	32.60	
0057603900	REFRACTORS POLYCARBON #	0.00	
0057604020	REFRACTOR POLY LU B2214	48.03	
0057604050	REFRACTOR POLY LU B2217	73.74	
0057604080	REFRACTOR POLYCARBON #9	21.07	
0057604170	REFRACTOR GLASS	66.37	
0057604200	REFRACTOR ACRYLIC VB15	40.70	
0057604210	REFRACTOR POLY LUM VB15	78.68	
0057604220	REFRACTOR AREA LIGHT	18.99	
0057604240	REFRACTOR GLASS OV15	16.00	
0057604250	REFRACTOR POLY LUM 0V15	24.00	
0057604255	REFRACTOR STREETLIGHT OV	18.12	
0057604270	REFRACTOR GLASS OV25	25.89	
0057604280	REFRACTOR POLY OV25	92.87	
0057604300	REFRACTOR GLASS OV50	17.50	
0057605800	REDUCER LAMPHOLDER,	6.25	
0057606100	REFRACTOR 125 W M V	34.36	
0057606500	REFRACTOR FOR SODIUM	71.31	
0057606550	REFRACTOR FOR SODIUM	88.62	
0057606700	REFRACTOR 250 W M V	38.69	
0057606950	REFRACTOR 400 W M V	33.01	
0057607300	RELAY 30 AMP 110 V MURC	33.89	
0057607330	RELAY 30 AMP 125 V	140.04	
0057607400	RELAY 60 AMP 115 V	214.85	
0057607440	RELAY 60 AMP 250 V	191.29	
0057608690	STARTERS HPS LUMINAIRES	31.63	
0057608700	STARTER FOR HPS 70-150W	40.95	
0057608703	STARTER FOR HPS 55V	41.17	
0057608710	STARTER FOR SODIUM	40.41	
0057608713	STARTER KIT HPS 55V 70/	31.75	
0057608720	STARTER FOR HPS 150-400	40.76	

SCHEDULE 7

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057608722	STARTER FOR HPS 100V	36.35	
0057608730	STARTER FOR SODIUM	48.16	
0065734220	CABLE CU ST-LITE 2C #12	1.03	

SCHEDULE 8

2013 Rate Stablization - STREET / CROSSWALK LIGHTING STUDY
LAMP LIFE ANALYSIS
September 2005

Assumptions: Total annual photocell operating time is based on 4,000 hours per year or 333 hours per month.
All Average Rated Life Spans are as indicated in the IES Lighting Handbook, 1981 Edition
(IES = Illuminating Engineering Society)

Lamp Type	Average Life (Hrs)	Burning Hours per Year	Service Life (Years)	Life Relative to 100W HPS	Replacements Relative to 100W HPS
Incandescent	2500	4000	0.6	0.10	9.60
Flourescent (48 in., T12, Recess Base)	12000	4000	3.0	0.50	2.00
Mercury Vapour	24000	4000	6.0	1.00	1.00
Mercury Vapour 125W *See Note	18000	4000	4.5	0.75	1.33
Metal Halide 175W	7500	4000	1.9	0.31	3.20
Metal Halide 250W	10000	4000	2.5	0.42	2.40
Metal Halide 400W	15000	4000	3.8	0.63	1.60
Metal Halide 1000W	10000	4000	2.5	0.42	2.40
High Pressure Sodium 70W	24000	4000	6.0	1.00	1.00
High Pressure Sodium 100W	24000	4000	6.0	1.00	1.00
Low Pressure Sodium	8000	4000	2.0	0.33	3.00

*** No Average life data was available for this lamp size in the references listed above. 75% of the quoted life for all Mercury Lamps was used.**

Nova Scotia Power Inc.
LED Streetlights
2013 Rate Stabilization
CCA Schedule
Millions of dollars

Schedule 9

		1	2	3	4	5	6	7	8	9
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
		12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
Beginning UCC										
	8%	-	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320
		-	**-**	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**
Additions										
	8%		16,924,872	17,322,621	-	-	-	-	-	-
		-	**16,924,872**	**17,322,621**	**-**	**-**	**-**	**-**	**-**	**-**
CCA										
	8%	-	676,995	1,992,735	2,526,221	2,324,123	2,138,193	1,967,138	1,809,767	1,664,986
		-	**676,995**	**1,992,735**	**2,526,221**	**2,324,123**	**2,138,193**	**1,967,138**	**1,809,767**	**1,664,986**
Ending UCC										
	8%	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320	19,147,335
		-	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**	**19,147,335**
	Tax Rate:	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	Tax Savings from CCA :	-	209,868	617,748	783,129	720,478	662,840	609,813	561,028	516,146

Nova Scotia Power Inc.
LED Streetlights
2013 Rate Stabilization
CCA Schedule
Millions of dollars

Schedule 9

	10 2021 12/31/2021	11 2022 12/31/2022	12 2023 12/31/2023	13 2024 12/31/2024	14 2025 12/31/2025	15 2026 12/31/2026	16 2027 12/31/2027	17 2028 12/31/2028	18 2029 12/31/2029	19 2030 12/31/2030
Beginning UCC										
	19,147,335	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632
	19,147,335	**17,615,548**	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**
Additions										
	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
CCA										
	1,531,787	1,409,244	1,296,504	1,192,784	1,097,361	1,009,572	928,807	854,502	786,142	723,251
	1,531,787	**1,409,244**	**1,296,504**	**1,192,784**	**1,097,361**	**1,009,572**	**928,807**	**854,502**	**786,142**	**723,251**
Ending UCC										
	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381
	17,615,548	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	474,854	436,866	401,916	369,763	340,182	312,967	287,930	264,896	243,704	224,208

Nova Scotia Power Inc. | **Schedule 9**
LED Streetlights
2013 Rate Stabilization
CCA Schedule
Millions of dollars

	20	21	22	23	24	25	26	27	
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	
	1/1/2031	1/2/2031	1/3/2031	1/4/2031	1/5/2031	1/6/2031	1/7/2031	1/8/2031	**Total**
Beginning UCC									
	8,317,381	7,651,991	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	**357,611,954**
	8,317,381	**7,651,991**	**7,039,831**	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**357,611,954**
Additions									
	-	-	-	-	-	-	-	-	
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**34,247,493**
CCA									
	665,390	612,159	563,187	518,132	476,681	438,547	403,463	371,186	**29,978,856**
	665,390	**612,159**	**563,187**	**518,132**	**476,681**	**438,547**	**403,463**	**371,186**	**29,978,856**
Ending UCC									
	7,651,991	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	4,268,637	**361,880,591**
	7,651,991	**7,039,831**	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**4,268,637**	**361,880,591**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	**8**
	206,271	189,769	174,588	160,621	147,771	135,949	125,073	115,068	**9,293,445**

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent :														
Incandescent < 300 Watts - Note 1	001	97	$13.72	4.04	$1.85	$19.61	$6,352	$17.54	11.8%	27	$669	0.291	7.857	
Incandescent > 300 Watts - Note 1	002	154	21.78	4.04	1.96	$27.78	667	$24.55	13.1%	2	77	0.462	0.924	
Incandescent < 300 Watts - Note 1	003	97	13.72	0.00	0.00	$13.72	1,152	$11.68	17.5%	7	171	0.291	2.037	
							8,171			36	917			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43	6.08	4.04	3.06	$13.18	36,948	$12.71	3.7%	234	1,317	0.129	30.144	
Mercury Vapour 125 Watts	101	52	7.35	5.38	2.88	$15.61	1,804,870	$14.74	5.9%	9,635	101,246	0.156	1,503.026	
Mercury Vapour 175 Watts	102	69	9.76	4.04	2.85	$16.65	460,171	$15.52	7.3%	2,303	31,113	0.207	476.775	
Mercury Vapour 250 Watts	103	97	13.72	4.04	3.51	$21.27	226,448	$19.82	7.3%	887	15,472	0.291	258.184	
Mercury Vapour 400 Watts	104	154	21.78	4.04	3.59	$29.40	304,177	$26.78	9.8%	862	27,168	0.462	398.287	
Mercury Vapour 700 Watts	105	260	36.77	4.04	4.67	$45.48	6,003	$41.04	10.8%	11	586	0.780	8.580	
Mercury Vapour 1000 Watts	106	363	51.33	4.04	5.62	$60.99	62,939	$54.75	11.4%	86	6,438	1.089	93.654	
Mercury Vapour 250 Watt Cont. Oper.	107	212	23.28	8.07	3.51	$34.87	1,255	$31.61	10.3%	3	117	0.291	0.873	0.873
Mercury Vapour 125 Watts	201	52	7.35	5.38	0.00	$12.73	1,070	$11.12	14.6%	7	136	0.156	1.092	
Mercury Vapour 175 Watts	202	69	9.76	4.04	0.00	$13.80	3,477	$11.94	15.6%	21	468	0.207	4.347	
Mercury Vapour 250 Watts	203	97	13.72	4.04	0.00	$17.76	7,458	$15.33	15.8%	35	1,020	0.291	10.185	
Mercury Vapour 400 Watts	204	154	21.78	4.04	0.00	$25.82	2,788	$22.19	16.4%	9	392	0.462	4.158	
Mercury Vapour 700 Watts	205	260	36.77	4.04	0.00	$40.81	0	$34.97	16.7%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363	51.33	4.04	0.00	$55.37	14,617	$47.38	16.9%	22	2,109	1.089	23.958	
Mercury Vapour 125 Watts	301	52	7.35	0.00	0.00	$7.35	970	$6.25	17.6%	11	145	0.156	1.716	
Mercury Vapour 175 Watts	302	69	9.76	0.00	0.00	$9.76	18,388	$8.29	17.7%	157	2,769	0.207	32.499	
Mercury Vapour 250 Watts	303	97	13.72	0.00	0.00	$13.72	8,891	$11.68	17.5%	54	1,322	0.291	15.714	
Mercury Vapour 400 Watts	304	154	21.78	0.00	0.00	$21.78	3,920	$18.54	17.5%	15	583	0.462	6.930	
Mercury Vapour 700 Watts	305	260	36.77	0.00	0.00	$36.77	441	$31.32	17.4%	1	65	0.780	0.780	
Mercury Vapour 1000 Watts	306	363	51.33	0.00	0.00	$51.33	4,312	$43.73	17.4%	7	638	1.089	7.623	
							2,969,145			14,360	193,104			

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30	4.24	8.07	2.35	$14.67	157,874	$13.82	6.1%	897	9,124	0.091	81.627	
Fluorescent 2x48" 220 Watts	111	85	12.02	8.07	2.59	$22.68	31,026	$20.76	9.3%	114	2,629	0.254	28.956	
Fluorescent 2x72" 300 Watts	112	116	16.40	8.07	3.01	$27.49	22,101	$25.09	9.5%	67	1,925	0.348	23.316	
Fluorescent 4x72" 600 Watts	113	222	31.39	8.07	4.07	$43.53	7,836	$39.26	10.9%	15	768	0.665	9.975	
Fluorescent 1x96" 110 Watts	114	47	6.65	8.07	2.84	$17.57	1,054	$16.52	6.3%	5	63	0.141	0.705	
Fluorescent 1x72" 150 Watts	115	60	8.48	8.07	2.49	$19.04	229	$17.61	8.1%	1	17	0.180	0.180	
Fluorescent 4x48" 440 Watts	116	166	23.47	8.07	3.11	$34.65	832	$31.25	10.9%	2	82	0.499	0.998	
							220,951			1,101	14,608			
Fluorescent 4x72" 600 Watts	213	222	31.39	8.07	0.00	$39.46	0	$34.02	16.0%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47	6.65	8.07	0.00	$14.72	4,594	$12.95	13.7%	26	554	0.141	3.666	
Fluorescent 1x72" 150 Watts	215	60	8.48	8.07	0.00	$16.55	596	$14.53	14.0%	3	73	0.180	0.540	
Fluorescent 4x48" 440 Watts	216	166	23.47	8.07	0.00	$31.54	0	$27.32	15.5%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49	6.93	8.07	0.00	$15.00	180	$13.18	13.9%	1	22	0.146	0.146	
Fluorescent 2x48" 220 Watts	218	85	12.02	8.07	0.00	$20.09	0	$17.54	14.6%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47	6.65	0.00	0.00	$6.65	160	$5.65	17.7%	2	24	0.140	0.280	
							5,530			32	673			
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486	53.36	0.00	0.00	$53.36	640	$45.45	17.4%	1	95	0.665	0.665	0.665
Fluorescent 2x24" 70 Watts	118	66	7.25	0.00	0.00	$7.25	1,479	$6.16	17.7%	17	222	0.091	1.547	1.547
Fluorescent 4x48" 440 Watts	119	364	39.97	0.00	0.00	$39.97	11,032	$34.06	17.4%	23	1,631	0.499	11.477	11.477
Fluorescent 2x96"	120	254	27.89	0.00	0.00	$27.89	10,040	$23.77	17.3%	30	1,483	0.348	10.440	10.440
Fluorescent 4x96"	150	613	67.31	0.00	0.00	$67.31	16,962	$57.34	17.4%	21	2,512	0.840	17.640	17.640
							40,154			92	5,943			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30	4.24	0.00	0.00	$4.24	102	$3.62	17.1%	2	15	0.091	0.182	
Fluorescent 4x48" 440 Watts	311	166	23.47	0.00	0.00	$23.47	1,408	$20.02	17.2%	5	207	0.499	2.495	
Fluorescent 2x72" 300 Watts	312	116	16.40	0.00	0.00	$16.40	197	$13.99	17.2%	1	29	0.348	0.348	
Fluorescent 4x72" 600 Watts	313	222	31.39	0.00	0.00	$31.39	0	$26.72	17.5%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47	6.65	0.00	0.00	$6.65	1,995	$5.65	17.7%	25	300	0.142	3.550	
Fluorescent 1x72" 150 Watts	315	60	8.48	0.00	0.00	$8.48	0	$7.23	17.3%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280	39.59	0.00	0.00	$39.59	36,106	$33.74	17.3%	76	5,335	0.841	63.916	
							39,808			109	5,886			

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60	8.48	12.11	5.44	$26.03	15,413	$25.30	2.9%	49	433	0.180	8.882	
Low Pressure Sodium 180 Watts	131	80	11.31	12.11	7.82	$31.25	169,300	$30.97	0.9%	452	1,495	0.240	108.367	
Low Pressure Sodium 90 Watts	132	45	6.36	12.11	5.44	$23.91	0	$23.48	1.8%	0	0	0.135	0.000	
Low Pressure Sodium 180 Watts E&M	231	80	11.31	12.11	0.00	$23.42	10,961	$20.59	13.8%	39	1,327	0.240	9.360	
Low Pressure Sodium 180 Watts E/O	331	80	11.31	0.00	0.00	$11.31	5,022	$9.64	17.3%	37	741	0.240	8.880	
							200,696			577	3,996			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100	14.14	4.04	3.07	$21.25	1,024,956	$19.59	8.5%	4,019	80,247	0.300	1,205.721	
High Pressure Sodium 400 Watts	122	150	21.21	4.04	3.18	$28.43	924,210	$25.75	10.4%	2,709	86,957	0.450	1,219.128	
High Pressure Sodium 70 Watts	123	32	4.53	4.04	2.90	$11.46	4,608,356	$11.14	3.0%	33,496	132,199	0.096	3,215.614	
High Pressure Sodium 100 Watts	124	45	6.36	4.04	2.92	$13.32	6,456,837	$12.74	4.6%	40,402	281,418	0.135	5,454.262	
High Pressure Sodium 150 Watts	125	65	9.19	4.04	3.08	$16.31	954,929	$15.38	6.1%	4,879	54,524	0.195	951.464	
HP Sodium 100 Watts - Cont. Oper.	126	99	10.87	8.07	2.92	$21.87	3,936	$20.22	8.2%	15	297	0.135	2.025	2.025
High Pressure Sodium 250 Watts	221	100	14.14	4.04	0.00	$18.18	37,300	$15.70	15.8%	171	5,086	0.300	51.300	
High Pressure Sodium 70 Watts	222	32	4.53	4.04	0.00	$8.57	26,524	$7.49	14.4%	258	3,339	0.096	24.768	
High Pressure Sodium 100 Watts	223	45	6.36	4.04	0.00	$10.40	16,844	$9.06	14.8%	135	2,168	0.135	18.225	
High Pressure Sodium 150 Watts	224	65	9.19	4.04	0.00	$13.23	36,507	$11.48	15.2%	230	4,826	0.195	44.850	
High Pressure Sodium 250 Watts	321	100	14.14	0.00	0.00	$14.14	163,572	$12.05	17.3%	964	24,177	0.300	289.200	
High Pressure Sodium 70 Watts	322	32	4.53	0.00	0.00	$4.53	324,964	$3.84	18.0%	5,978	49,498	0.096	573.888	
High Pressure Sodium 100 Watts	323	45	6.36	0.00	0.00	$6.36	181,413	$5.41	17.6%	2,377	27,098	0.135	320.895	
High Pressure Sodium 150 Watts	324	65	9.19	0.00	0.00	$9.19	13,785	$7.83	17.4%	125	2,040	0.195	24.375	
High Pressure Sodium 400 Watts	326	150	21.21	0.00	0.00	$21.21	22,652	$18.07	17.4%	89	3,354	0.450	40.050	
High Pressure Sodium 500 Watts	327	183	25.88	0.00	0.00	$25.88	932	$22.05	17.4%	3	138	0.550	1.650	
High Pressure Sodium 1000 Watts	328	363	51.33	0.00	0.00	$51.33	8,623	$43.74	17.4%	14	1,275	1.090	15.260	
High Pressure Sodium 1500 Watts	329	500	70.70	0.00	0.00	$70.70	848	$60.23	17.4%	1	126	1.090	1.090	
							14,807,188			95,865	758,641			

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150	21.21	6.46	3.62	$31.29	423,982	$28.54	9.6%	1,129	37,234	0.450	508.179	
Metallic Arc 1000 Watts	141	360	50.91	9.69	5.23	$65.83	774,961	$58.97	11.6%	981	80,819	1.080	1,059.480	
Metallic Arc 250 Watts	142	100	14.14	9.69	3.56	$27.39	30,511	$25.36	8.0%	93	2,259	0.300	27.847	
Metallic Arc 150 Watts	143	67	9.47	9.69	3.56	$22.72	1,091	$21.37	6.3%	4	65	0.200	*0.800*	
Metallic Arc 100 Watts	144	50	7.07	9.69	3.56	$20.32	1,589	$19.33	5.1%	7	77	0.150	0.978	
Metallic Arc 1000 Watts	341	360	50.91	0	0	$50.91	13,440	$43.37	17.4%	22	1,991	1.080	23.760	
Metallic Arc 400 Watts	342	150	21.21	0	0	$21.21	40,469	$18.07	17.4%	159	5,991	0.450	71.550	
Metallic Arc 250 Watts	343	100	14.14	0	0	$14.14	14,253	$12.05	17.3%	84	2,107	0.300	25.200	
Metallic Arc 175 Watts	344	75	10.61	0	0	$10.61	14,260	$9.03	17.5%	112	2,124	0.225	25.200	
Metallic Arc 150 Watts	345	67	9.47	0	0	$9.47	2,273	$8.06	17.5%	20	338	0.200	4.000	
Metallic Arc 100 Watts	346	50	7.07	0	0	$7.07	0	$6.02	17.4%	0	0	0.150	0.000	
							1,316,829			2,611	133,005			
Light Emitting Diode - Traffic Lights														
Light Emitting Diode 4.6 Watts	530	3	0.34	0	0	$0.34	0	$0.29	19.2%		0		0.000	
Light Emitting Diode 7.5 Watts	531	5	0.58	0	0	$0.58	0	$0.49	17.6%		0		0.000	
							0							
Light Emitting Diode (Energy Only)														
Lighting Emitting Diode 44 Watts	532	15	2.12	0	0	$2.12	44,062	$1.81	17.1%	1,732	6,443	0.440	762.080	
Lighting Emitting Diode 66 Watts	533	22	3.11	0	0	$3.11	5,150	$2.65	17.4%	138	762	0.660	91.080	
Lighting Emitting Diode 88 Watts	534	29	4.10	0	0	$4.10	25,240	$3.49	17.5%	513	3,755	0.880	451.440	
Lighting Emitting Diode 92 Watts	535	31	4.38	0	0	$4.38	0	$3.73	17.4%	0	0	0.920	0.000	
Lighting Emitting Diode 105 Watts	536	35	4.95	0	0	$4.95	0	$4.22	17.3%	0	0	0.105	0.000	
Lighting Emitting Diode 170 Watts	537	57	8.06	0	0	$8.06	0	$6.87	17.3%	0	0	0.170	0.000	
Lighting Emitting Diode 110 Watts	539	37	5.23	0	0	$5.23	163,741	$4.46	17.3%	2,609	24,107	0.110	286.990	
Lighting Emitting Diode 65 Watts	540	22	3.11	0	0	$3.11	17,316	$2.65	17.4%	464	2,561	0.650	301.600	
Lighting Emitting Diode 55 Watts	541	18	2.55	0	0	$2.55	22,522	2.17	17.5%	736	3,356	0.550	404.800	
Lighting Emitting Diode 83 Watts	542	28	3.96	0	0	$3.96	49,373	3.37	17.5%	1,039	7,356	0.830	862.370	
Lighting Emitting Diode 48 Watts	543	16	2.26	0	0	$2.26	1,953	1.93	17.1%	72	285	0.830	59.760	
Lighting Emitting Diode 72 Watts	544	24	3.39	0	0	$3.39	12,529	2.89	17.3%	308	1,848	0.830	255.640	
							341,886			7,611				

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Light Emitting Diode (Energy & Capital														
LED A1	615	15	2.12	0	8.06	$10.18	678,771	8.65	17.7%	5,555	102,008	0.830	4,610.728	
LED A2	616	18	2.55	0	8.06	$10.61	202,214	9.04	17.4%	1,588	29,920	0.830	1,317.933	
LED A4	617	25	3.54	0	8.06	$11.60	52,814	9.97	16.3%	379	7,421	0.830	314.848	
LED A3	618	29	4.10	0	8.06	$12.16	1,186	10.49	15.9%	8	163	0.830	6.745	
LED B1	619	22	3.11	0	8.06	$11.17	892,423	11.75	-4.9%	6,656	(45,936)	0.830	5,524.856	
LED C1	620	29	4.10	0	8.06	$12.16	149,464	13.82	-12.0%	1,024	(20,419)	0.830	849.988	
LED C3	621	37	5.23	0	8.06	$13.29	123,485	14.88	-10.7%	774	(14,785)	0.830	642.549	
LED C2	622	58	8.20	0	8.06	$16.26	132,285	17.65	-7.9%	678	(11,319)	0.830	562.628	
							2,232,641			16,663				
TOTALS							**$22,182,998**			**139,057**			**35,794.276**	**44.667**
										122,394				

Non LED	**114,783**
LED	**24,274**
Total	**139,057**
Non LED	
Energy Only	103,386
Maintenance	957
Capital	10,440
Total	114,783
LED	
Energy Only	7,611
Capital	16,663
Total	24,274
Grand Total	139,057

SCHEDULE 10

2013 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2013

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2013 New Proposed Rates	2013 New Proposed Revenue	2012 Current Rates	Percent Change	2013 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)

Count = 105

Note 1 - Red highligted P&E charges relate to calculated rounding differences using Misc. Small Loads Tariff.

Note 2 - Incandescent rates were set at 250W and 400W Mercury Vapour

Miscellaneous Small Loads Rate		
Demand Charge	$/kW	9.339
Block 1 Energy		
Base cost of fuel	¢/kWh	5.087
Non-fuel	¢/kWh	5.593
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 1 (first 200kWh *	¢/kWh	**10.680**
Block 2 Energy		
Base cost of fuel	¢/kWh	5.087
Non-fuel	¢/kWh	2.004
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 2	¢/kWh	**7.091**

Calculation of Power & Energy Rate :
Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

Photocell Operation (4000 burning hours per year)			
Demand Charge $/kW (annual)		10.963	$131.55
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.12537	300.89
2nd Block : All additional (annual)	1,600	0.08324	133.18
			$565.63
Rate per kW.h	4,000		**$0.1414063**
Continuous Burning (8760 burning hours per year)			
Demand Charge $/kW (annual)		10.963	$131.55
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.12537	300.89
2nd Block : All additional (annual)	6,360	0.08324	529.41
			$961.85
Rate per kW.h	8,760		**$0.1097999**

Street / Crosswalk Lighting Study

2014 Schedules - Rate Stabilization

SCHEDULE 1

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

		MARCH 2013 (Quantity)				FORECAST 2014 (Quantity)				Full Charge
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	Adj. for LED Conv.
001/003	Incandescent < 300 Watts	27	0	7	34	27	0	7	34	27
002	Incandescent > 300 Watts	2	0	0	2	2	0	0	2	2
		29	0	7	36	29	0	7	36	29
100	Mercury Vapour 100 Watts	216	0	0	272	216	0	0	216	189
101/201/301	Mercury Vapour 125 Watts	8,921	7	11	11,240	8921	7	11	8939	7778
102/202/302	Mercury Vapour 175 Watts	2,133	21	157	2,861	2133	21	157	2311	1859
103/203/303	Mercury Vapour 250 Watts	821	35	54	1,122	821	35	54	910	716
104/204/304	Mercury Vapour 400 Watts	798	9	15	1,028	798	9	15	822	696
105/205/305	Mercury Vapour 700 Watts	11	0	1	12	11	0	1	12	11
106/206/306	Mercury Vapour 1000 Watts	86	22	7	115	86	22	7	115	86
107	Mercury Vapour 250 Watt Cont. Oper.	3	0	0	3	3	0	0	3	3
		12,989	94	245	16,653	12989	94	245	13328	11338
110	Fluorescent 2x24" 70 Watts	897	0	0	897	897	0	0	897	897
111	Fluorescent 2x48" 220 Watts	114	0	0	114	114	0	0	114	114
112	Fluorescent 2x72" 300 Watts	67	0	0	67	67	0	0	67	67
113/213	Fluorescent 4x72" 600 Watts	15	0	0	15	15	0	0	15	15
114/214	Fluorescent 1x96" 110 Watts	5	26	0	31	5	26	0	31	5
115/215	Fluorescent 1x72" 150 Watts	1	3	0	4	1	3	0	4	1
116	Fluorescent 4x48" 440 Watts	2	0	0	2	2	0	0	2	2
217	Fluorescent 1x48"	0	1	0	1	0	1	0	1	0
218	Fluorescent 2x48"	0	0	0	0	0	0	0	0	0
330	Fluorescent 4x35"	0	0	2	2	0	0	2	2	0
350	Fluorescent 4x96"	0	0	76	76	0	0	76	76	0
		1,101	30	78	1,209	1101	30	78	1209	1,101
117	Fluorescent Crosswalk Cont. 4x72"	0	0	1	1	0	0	1	1	0
118	Fluorescent Crosswalk Cont. 2x24"	0	0	17	17	0	0	17	17	0
119	Fluorescent Crosswalk Cont. 4x48"	0	0	23	23	0	0	23	23	0
120	Fluorescent Crosswalk Cont. 2x96"	0	0	30	30	0	0	30	30	0
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21	0	0	21	21	0
		0	0	92	92	0	0	92	92	0
310	Fluorescent Crosswalk 2x24"	0	0	2	2	0	0	2	2	0
311	Fluorescent Crosswalk 4x48"	0	0	5	5	0	0	5	5	0
312	Fluorescent Crosswalk 2x72"	0	0	1	1	0	0	1	1	0
313	Fluorescent Crosswalk 4x72"	0	0	0	0	0	0	0	0	0
314	Fluorescent Crosswalk 1x96"	0	0	25	25	0	0	25	25	0
315	Fluorescent Crosswalk 1x72"	0	0	0	0	0	0	0	0	0
		0	0	33	33	0	0	33	33	0

SCHEDULE 1

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

		MARCH 2013 (Quantity)				FORECAST 2014 (Quantity)				Full Charge Adj. for LED Conv.
Rate Code	Description	Full Charge	Energy & Maint	Energy Only	Total	Full Charge	Energy & Maint	Energy Only	Total	
121/221/321	High Pressure Sodium 250 Watts	3,721	171	964	5,816	3721	171	964	4856	3,244
122/326	High Pressure Sodium 400 Watts	2,508	0	89	3,244	2508	0	89	2597	2,187
123/222/322	High Pressure Sodium 70 Watts	31,013	258	5,978	45,249	31013	258	5978	37249	27,040
124/223/323	High Pressure Sodium 100 Watts	37,406	135	2,377	49,570	37406	135	2377	39918	32,612
125/224/324	High Pressure Sodium 150 Watts	4,518	230	125	6,038	4518	230	125	4873	3,939
126	HP Sodium 100 Watts - Cont. Oper.	15	0	0	15	15	0	0	15	15
327	High Pressure Sodium 500 Watts	0	0	3	3	0	0	3	3	0
328	High Pressure Sodium 1000 Watts	0	0	14	14	0	0	14	14	0
329	High Pressure Sodium 1500 Watts	0	0	1	1	0	0	1	1	0
		79,181	794	9,551	109,950	79181	794	9551	89526	69,038
130	Low Pressure Sodium 135 Watts	46	0	0	58	46	0	0	46	40
131/231/331	Low Pressure Sodium 180 Watts	418	39	37	602	418	39	37	494	365
132	Low Pressure Sodium 90 Watts	0	0	0	0	0	0	0	0	0
		464	39	37	660	464	39	37	540	404
140/342	Metallic Arc 400 Watts	1,046	0	159	1,474	1046	0	159	1205	912
141/341	Metallic Arc 1000 Watts	981	0	22	1,003	981	0	22	1003	981
142/343	Metallic Arc 250 Watts	86	0	84	193	86	0	84	170	74
143	Metallic Arc 150 Watts	4	0	0	4	4	0	0	4	4
144	Metallic Arc 100 Watts	5	0	0	7	5	0	0	5	4
344	Metallic Arc 175 Watts	0	0	112	112	0	0	112	112	0
345	Metallic Arc 150 Watts	0	0	20	20	0	0	20	20	0
346	Metallic Arc 100 Watts	0	0	0	0	0	0	0	0	0
		2,121	0	397	2,813	2121	0	397	2518	1,975
532/538	LED 44 Watts	0	0	1,732	1,732	0	0	1732	1732	0
539	LED 110 Watts	0	0	2,609	2,609	0	0	2609	2609	0
533	LED 66 Watts	0	0	138	138	0	0	138	138	0
534	LED 88 Watts	0	0	513	513	0	0	513	513	0
537	LED 173 Watts	0	0	38	38					
540	LED 65 Watts	0	0	464	464	0	0	464	464	0
541	LED 55 Watts	0	0	736	736	0	0	736	736	0
542	LED 83 Watts	0	0	1,039	1,039	0	0	1039	1039	0
543	LED 48 Watts	0	0	72	72	0	0	72	72	0
544	LED 72 Watts	0	0	308	308	0	0	308	308	0
	Total	0	0	7,649	7,649	0	0	7649	7649	0
	LED A	20,572				20,572			20572	30,789
	LED B	2,608	0	0	0	2,608			2608	3,903
	LED C	983	0	0	0	983			983	1,471
	Total	24,163	0	0	0	24,163			24163	36,163
	Total	**120,048**	**957**	**18,089**	**139,095**	**120,048**	**957**	**18,089**	**139,094**	**120,048**

SCHEDULE 2

2014 - Rate Stabilization STREET / CROSSWALK LIGHTING STUDY
CALCULATION OF MAINTENANCE COSTS BY FIXTURE TYPE

(A) Code	(B) Lamp Type	(C) Service Life (Years)	(D) Maintenance Weighting Factors	(E) # of Full Chg & Eng.+Maint. Fixtures	(F) Weighting Total	(G) Cost Per Year	(H) Cost Per Month
A	Mercury Vapour	6.000	1.0000	3,676	3,676	$61.07	$5.09
B	Mercury Vapour - 125W	4.500	1.3333	7,785	10,380	$81.42	$6.79
C	Fluorescent	3.000	2.0000	1,131	2,262	$122.13	$10.18
D	High Pressure Sodium (Note1)	6.000	1.0000	69,847	69,847	$61.07	$5.09
E	Metallic Arc 100W, 150W & 250W	2.500	2.4000	83	198	$146.56	$12.21
F	Metallic Arc 400W	3.750	1.6000	912	1,459	$97.70	$8.14
G	Metallic Arc 1000W	2.500	2.4000	981	2,354	$146.56	$12.21
H	Low Pressure Sodium	2.000	3.0000	443	1,330	$183.20	$15.27
I	LED	20.000	0.3000	0	0	$18.32	$1.53
				84,857	91,506		

Street Lighting Maint. Expenses
(from 2014 COSS, Exhibit 6A) **$5,587,803**

Annual Cost of High Pressure Sodium
($5,587,802.73 / 91505.5890121691 weighted fixtures) **$61.07**

Note 1: Maintenance weighting factors relative to High Pressure Sodium fixture, index = 1.0
Factor is: HPS service life / various fixture service lives

SCHEDULE 3

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

Gross Plant Value (including installation costs) less Retirements of Non-LED Street Lighting Equipment, 2013 Average --------→ **Total** **$35,521,858**

Description	Unit Cost Mar/1977	Unit Cost Mar-11	Historical 11-Mar Fixtures	Average # of Fixtures ɛginning of Yɛ	Avg # of Fixtures End of Year	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	27	27	27	$1,733	
Incandescent > 300 Watts	$63.62	$79.53	2	2	2	$159	
Mercury Vapour 100 Watts	$76.55	$229.55	216	216	189	$49,664	
Mercury Vapour 125 Watts	$77.16	$204.78	8,921	8,921	7,778	$1,826,771	
Mercury Vapour 175 Watts	$85.30	$201.27	2,133	2,133	1,859	$429,217	
Mercury Vapour 250 Watts	$87.24	$291.38	821	821	716	$239,354	
Mercury Vapour 400 Watts	$107.82	$301.45	798	798	696	$240,614	
Mercury Vapour 700 Watts	$485.12	$449.78	11	11	11	$4,948	
Mercury Vapour 1000 Watts	$492.29	$579.25	86	86	86	$49,816	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$291.38	3	3	3	$874	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	897	897	897	$119,346	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	114	114	114	$18,797	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	67	67	$14,968	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	15	15	$5,507	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	5	5	$1,000	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	1	1	1	$152	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	2	2	$472	
High Pressure Sodium 70 Watts	*N/A*	$207.51	31,013	31,013	27,040	$6,435,494	
High Pressure Sodium 100 Watts	*N/A*	$210.65	37,421	37,421	32,627	$7,882,559	
High Pressure Sodium 150 Watts	*N/A*	$232.66	4,518	4,518	3,939	$1,051,088	
High Pressure Sodium 250 Watts	$156.49	$231.67	3,721	3,721	3,244	$862,095	
High Pressure Sodium 400 Watts	$173.73	$246.21	2,508	2,508	2,187	$617,586	
High Pressure Sodium 1000 Watts	*N/A*	$615.53	0	0	0	$0	
Low Pressure Sodium 90 Watts	*N/A*	$554.53	0	0	0	$0	
Low Pressure Sodium 135 Watts	$371.69	$554.53	46	46	40	$25,334	
Low Pressure Sodium 180 Watts	$226.10	$880.14	418	418	365	$367,949	
Metallic Additive 250 Watts	*N/A*	$298.33	90	90	78	$26,744	
Metallic Additive 400 Watts	$358.84	$305.76	1,046	1,046	912	$319,693	
Metallic Additive 1000 Watts	$560.49	$526.16	981	981	981	$516,159	
Metallic Additive 100 Watts	*N/A*		5	5	4	$0	
			95,885	95,885	83,885		**21,108,091**

$14,413,767

$171.83

Total # of light types being displaced by LED — 93,674 | 93,674

Total Installation Costs (Labour)

Installation Costs per Fixture

Escalation Factor (Incandescent)	125%
Escalation Factor (Fluorescent)	125%

Note: 2007 costs are based on stores material inventory cost as of June 2007 with the exception of Incandescent and fluorescent which have been assumed at 130% of 1977 costs.

Sample Material Cost - 100 Watt High Intensity (Pressure) Sodium :
Inventory Prices as of March 2011

Fixture, Ballast & Photocell	$124.02
Bracket Assembly (Davit)	67.32
Wire	16.71
Miscellaneous Hardware	2.60
Lamp Replacement	8.62
TOTAL	**$219.27**

SCHEDULE 4

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

	Non Led	LED
Depreciation Rate for 2013	5.33%	5.33%
# of Years	18.76	18.76
Tax Adjusted Weighted Average Cost of Capital	10.47%	9.38%
Pre-tax WACC	7.83%	7.83%
Tax-related Gross-up Depreciation factor	31.00%	31.00%
Salvage Rate (% of Depreciation)	0.00%	0.00%
Salvage Rate incl in Depr. Rate for 2013	0.00%	0.00%
# of Years	N/A	N/A

Revenue Correction factor	Non LED	LED
Simulated at current meth.	$5,988,194	$3,846,850
Total cost per COSS (and adjusted for energy)	$3,140,581	$3,603,688
Revenue Correction Factor	**0.5245**	**0.9368**

				Before Correction Factor				Correction Factor	Aligned with COSS results		2013 Forecast					
	Material Cost January 2010	Labour Cost	Total	Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost		Total Annual Cost	Monthly Cost	# of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Incandescent < 300 Watts	$64.20	171.83	$236.03	$18.23	$24.71	$0.00	$42.94	0.524	$22.52	$1.88	27	492.27	667.23		1,159.50	608.11
Incandescent > 300 Watts	79.53	171.83	251.35	$19.42	$26.32	$0.00	45.73	0.524	$23.99	2.00	2	38.83	52.63		91.47	47.97
Mercury Vapour 100 Watts	229.55	171.83	401.37	$31.00	$42.02	$0.00	73.03	0.524	$38.30	3.19	189	5,848.73	7,927.38		13,776.11	7,225.05
Mercury Vapour 125 Watts	204.78	171.83	376.61	$29.09	$39.43	$0.00	68.52	0.524	$35.94	2.99	7,778	226,270.05	306,687.19		532,957.23	279,515.90
Mercury Vapour 175 Watts	201.27	171.83	373.10	$28.82	$39.06	$0.00	67.88	0.524	$35.60	2.97	1,859	53,587.24	72,632.33		126,219.58	66,197.39
Mercury Vapour 250 Watts	291.38	171.83	463.20	$35.78	$48.50	$0.00	84.28	0.524	$44.20	3.68	716	25,627.23	34,735.23		60,362.45	31,657.82
Mercury Vapour 400 Watts	301.45	171.83	473.28	$36.56	$49.55	$0.00	86.11	0.524	$45.16	3.76	696	25,442.77	34,485.21		59,927.98	31,429.96
Mercury Vapour 700 Watts	449.78	171.83	621.61	$48.02	$65.08	$0.00	113.10	0.524	$59.32	4.94	11	528.19	715.91		1,244.09	652.48
Mercury Vapour 1000 Watts	579.25	171.83	751.08	$58.02	$78.64	$0.00	136.66	0.524	$71.67	5.97	86	4,989.57	6,762.88		11,752.45	6,163.71
Mercury Vapour 250 Watt Cont. Oper.	291.38	171.83	463.20	$35.78	$48.50	$0.00	84.28	0.524	$44.20	3.68	3	107.34	145.49		252.83	132.60
Fluorescent 2x24" 70 Watts	133.05	171.83	304.88	$23.55	$31.92	$0.00	55.47	0.524	$29.09	2.42	897	21,124.97	28,632.85		49,757.82	26,096.09
Fluorescent 2x48" 220 Watts	164.89	171.83	336.72	$26.01	$35.25	$0.00	61.26	0.524	$32.13	2.68	114	2,965.14	4,018.96		6,984.11	3,662.90
Fluorescent 2x72" 300 Watts	223.40	171.83	395.23	$30.53	$41.38	$0.00	71.91	0.524	$37.71	3.14	67	2,045.50	2,772.48		4,817.98	2,526.85
Fluorescent 4x72" 600 Watts	367.15	171.83	538.98	$41.63	$56.43	$0.00	98.07	0.524	$51.43	4.29	15	624.51	846.46		1,470.98	771.47
Fluorescent 1x96" 110 Watts	200.00	171.83	371.83	$28.72	$38.93	$0.00	67.65	0.524	$35.48	2.96	5	143.61	194.65		338.26	177.41
Fluorescent 1x72" 150 Watts	151.53	171.83	323.35	$24.98	$33.86	$0.00	58.83	0.524	$30.86	2.57	1	24.98	33.86		58.83	30.86
Fluorescent 4x48" 440 Watts	236.14	171.83	407.97	$31.51	$42.71	$0.00	74.23	0.524	$38.93	3.24	2	63.03	85.43		148.46	77.86
High Pressure Sodium 70 Watts	207.51	171.83	379.34	$29.30	$39.72	$0.00	69.02	0.524	$36.20	3.02	27,040	792,341.06	1,073,941.75		1,866,282.81	978,794.70
High Pressure Sodium 100 Watts	210.65	171.83	382.47	$29.54	$40.04	$0.00	69.59	0.524	$36.50	3.04	32,627	963,959.25	1,306,553.62		2,270,512.86	1,190,798.06
High Pressure Sodium 150 Watts	232.66	171.83	404.49	$31.25	$42.35	$0.00	73.60	0.524	$38.60	3.22	3,939	123,072.73	166,813.19		289,885.92	152,034.19
High Pressure Sodium 250 Watts	231.67	171.83	403.50	$31.17	$42.25	$0.00	73.42	0.524	$38.50	3.21	3,244	101,126.64	137,067.39		238,194.03	124,923.76
High Pressure Sodium 400 Watts	246.21	171.83	418.04	$32.29	$43.77	$0.00	76.06	0.524	$39.89	3.32	2,187	70,623.39	95,723.18		166,346.57	87,242.48
High Pressure Sodium 1000 Watts	615.53	171.83	787.36	$60.82	$82.44	$0.00	143.26	0.524	$75.13	6.26	-	-	-		-	-
Low Pressure Sodium 90 Watts	554.53	171.83	726.36	$56.11	$76.05	$0.00	132.16	0.524	$69.31	5.78	-	-	-		-	-
Low Pressure Sodium 135 Watts	554.53	171.83	726.36	$56.11	$76.05	$0.00	132.16	0.524	$69.31	5.78	40	2,234.93	3,029.23		5,264.16	2,760.85
Low Pressure Sodium 180 Watts	880.14	171.83	1,051.97	$81.26	$110.14	$0.00	191.40	0.524	$100.38	8.37	365	29,619.72	40,146.67		69,766.40	36,589.84
Metallic Arc 250 Watts	298.33	171.83	470.15	$36.32	$49.23	$0.00	85.54	0.524	$44.86	3.74	78	2,838.65	3,847.51		6,686.16	3,506.64
Metallic Arc 400 Watts	305.76	171.83	477.59	$36.89	$50.00	$0.00	86.90	0.524	$45.57	3.80	912	33,631.79	45,584.64		79,216.43	41,546.02
Metallic Arc 1000 Watts	$526.16	171.83	$697.98	$53.92	$73.08	$0.00	$127.00	0.524	$66.60	$5.55	981	52,892.29	71,690.39		124,582.68	65,338.90
Metallic Additive 100 Watts	$0.00	171.83	$171.83	$13.27	$17.99	$0.00	$31.26	0.524	$16.40	$1.37	4	57.86	78.43		136.29	71.48
Total											**83,885**	**$2,542,322**	**$3,445,872**		**$5,988,194**	**$3,140,581**

				Before Correction Factor				Correction Factor	Aligned with COSS results		2013 Forecast					
	Material Cost January 2010	Labour Cost	Total	Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost		Total Annual Cost	Monthly Cost	# of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
LED A	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	0.937	$99.65	8.30	30,789	1,716,622.46	2,084,488.53	(525,943.92)	3,275,167.07	3,068,141.47
LED B	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	0.937	$99.65	8.30	3,903	217,612.68	264,246.31	(66,672.82)	415,186.16	388,941.96
LED C	$420.00	$301.78	$721.78	$55.75	$67.70	-$17.08	106.38	0.937	$99.65	8.30	1,471	82,025.13	99,602.82	(25,131.10)	156,496.85	146,604.57
											36,163	**$2,016,260**	**$2,448,338**	**-$617,748**	**$3,846,850**	**$3,603,688**

SCHEDULE 5

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Rate by Components For 2014 Street Light Rates

a) Weighted Average Cost of Capital - Pretax				**Non-LED**		**LED**
	Proportion	Cost	Extended		Extended	
ST Debt	6.7%	6.1%	0.4%	0.41%	0.4%	0.41%
LT Debt	52.1%	7.2%	3.8%	3.75%	3.8%	3.75%
Preferred	3.7%	6.0%	0.2%	0.22%	0.2%	0.22%
Common	37.5%	9.2%	3.5%	3.45%	3.5%	3.45%
	100.0%		7.8%		7.8%	
WACC - pretax cost				7.83%		7.83%
b) Additional income tax for common equity						
Extended equity cost			3.45%		3.45%	
Effective tax rate (excluding surtax)			31.0%		31.0%	
Income tax			1.55%		1.55%	
WACC - equity tax cost				1.55%		1.55%
c) Large Corporations Tax						
Provincial capital tax (2014)			0.000%		0.000%	
Federal capital tax (2014)			0.000%		0.000%	
Ave. NBV - Street Lighting			$10,251		$24,256	
Ave. NBV - Assigned GP Plt.			718.137		1,699.360	
Ave. Deferred Chgs & W/C			710.082		1,680.297	
NPV - Total Street Lighting			$11,678.828		$27,636.116	
Provincial capital tax			$0.000		$0.000	
Federal capital tax			$0.000		$0.000	
Total			$0.000		$0.000	
Percentage of NBV			0.00%		0.00%	
WACC - Large Corporations Tax				0.00%		0.00%
d) Grants in Lieu of Property Tax						
Total 2014 Forecasted Expense			$38.400		N/A	
St. Lgts. % of Total Electric Plant			331.58%		N/A	
St. Lgts. Allocated Amount			$127.327		N/A	
Percentage of NBV			1.09%		N/A	
WACC - Grants in Lieu of Property Tax				1.09%		0.00%
Total WACC - Interest / Carrying Cost				**10.47%**		**9.38%**

SCHEDULE 5A

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components

For 2014 Street Light Rates

Depreciation Rate		**5.33%**			
Salvage Rate		**0.00%**			
Salvage Incl. in Depreciation Rate		**0.00%**			
Gross-up factor for tax purposes (LED only)		**31.00%**			
		Non LED	**Non LED**	**LED**	**Year 2**
Gross Plant Value (YA)			$35,522	$25,586	
Net Plant Value (YA)			$10,251	$24,256	6,749
a) Weighted Average Cost of Capital - Pretax					
	ST Debt	0.41%		99	27
	LT Debt	3.75%		910	253
	Subtotal		*400*	*1,009*	*281*
	Preferred	0.22%	$22.8	54	15
	Common	3.45%	$344.5	837	233
	WACC - pretax cost	7.83%	$766.9	$1,899	$529
b) Additional income tax for common equity					
	WACC - equity tax cost	1.55%		376	105
c) Large Corporations Tax					
	WACC - Large Corporations Tax	0.00%		0	0
Subtotal			*$161.2*	*376*	*105*
d) Grants in Lieu of Property Tax					
	WACC - Grants in Lieu of Property Tax	1.09%	$106.5	0	74
Subtotal Financing Expense		**10.47%**	**$1,034.5**	**$2,275.4**	**$706.7**
Depreciation Expense			**$2,240.326**	**$1,364**	**$0.0**
Gross up for Tax Purposes				**$612.7**	**$0.0**
Total Depreciation Expense including Gross up for Tax Purposes			**$2,240.3**	**$1,976.4**	**$0.0**
CCA			**$0.0**	**-$617.7**	**$0.0**
TOTAL CAPITAL COST EXPENSE			**$3,140.6**	**$3,634.101**	**$706.715**

SCHEDULE 6

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY
AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

Light Type Street Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Incandescent < 300 Watts	$51.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Incandescent > 300 Watts	$63.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mercury Vapour 100 Watts	$229.55	$122.41	$15.99	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 125 Watts	$204.78	$102.95	$10.68	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 175 Watts	$201.27	$102.95	$7.17	$4.52	$67.32	$16.71	$1.09	$1.51
Mercury Vapour 250 Watts	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 400 Watts	$301.45	$198.75	$8.98	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 700 Watts	$449.78	$318.97	$37.10	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 1000 Watts	$579.25	$439.19	$46.35	$4.52	$69.88	$16.71	$1.09	$1.51
Mercury Vapour 250 Watt Cont. Oper.	$291.38	$189.80	$7.86	$4.52	$69.88	$16.71	$1.09	$1.51
Fluorescent 2x24" 70 Watts	$106.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x48" 220 Watts	$131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x72" 300 Watts	$178.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x72" 600 Watts	$293.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x96" 110 Watts	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x72" 150 Watts	$121.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x48" 440 Watts	$188.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High Pressure Sodium 70W	$207.51	$120.88	$8.81	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 100W	$210.65	$124.02	$8.62	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 150W	$232.66	$146.03	$8.67	$4.52	$67.32	$16.71	$1.09	$1.51
High Pressure Sodium 250 Watts	$231.67	$142.48	$10.59	$4.52	$69.88	$16.71	$1.09	$1.51
High Pressure Sodium 400 Watts	$246.21	$157.02	$13.19	$4.52	$69.88	$16.71	$1.09	$1.51
Low Pressure Sodium 90W	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 135 Watts	$554.53	$463.38	$44.00	$4.52	$67.32	$16.71	$1.09	$1.51
Low Pressure Sodium 180 Watts	$880.14	$788.99	$54.77	$4.52	$67.32	$16.71	$1.09	$1.51
Metallic Additive 250W	$298.33	$190.30	$18.83	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 400 Watts	$305.76	$201.63	$14.93	$0.00	$69.88	$16.71	$1.09	$1.51
Metallic Arc 1000 Watts	$526.16	$405.65	$31.31	$0.00	$69.88	$16.71	$1.09	$1.51
LED A	$420.00							
LED B	$420.00							
LED C	$420.00							

Light Type Flood Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Mercury Vapour 175 Watts	$67.32	$53.03	$7.17	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 250 Watts	$412.88	$397.90	$7.86	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 400 Watts	$297.27	$281.17	$8.98	$4.52	$0.00	$0.00	$1.09	$1.51
Mercury Vapour 1000 Watts	$507.90	$439.19	$46.35	$19.77	$0.00	$0.00	$1.09	$1.51
HIS 150W	$215.75	$183.39	$25.23	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 250 Watts	$202.12	$184.41	$10.59	$4.52	$0.00	$0.00	$1.09	$1.51
High Intensity Sodium 400 Watts	$215.26	$194.95	$13.19	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Additive 250W	$216.25	$190.30	$18.83	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 400 Watts	$223.69	$201.63	$14.93	$4.52	$0.00	$0.00	$1.09	$1.51
Metallic Arc 1000 Watts	$459.33	$405.65	$31.31	$19.77	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 70W HPS	$197.77	$195.17	$8.81	$4.52	$0.00	$0.00	$1.09	$1.51
Dusk-to-Dawn 100W HPS	$143.10	$140.50	$8.62	$4.52	$0.00	$0.00	$1.09	$1.51

SCHEDULE 7

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0000386440	LAMP FLUORESCENT 40W 48	1.35	
0000386450	LAMP FLUORESCENT 40W 48	1.36	
0000386700	LAMP FLUORESCENT 75W 96	3.49	
0000386710	LAMP FLUORESCENT 205W	3.95	
0000387070	LAMP FLUORESCENT 35W 24	4.19	
0000387190	LAMP FLUORESCENT 60W 48	3.19	
0000387360	LAMP FLUORESCENT 85W 72	6.54	
0000388000	LAMP 100 WATT M.V.	15.99	
0000388180	LAMP 125 WATT M.V.	10.68	
0000388330	LAMP 175 WATT M.V.	7.17	
0000388500	LAMP 250 WATT M.V.	7.86	
0000388660	LAMP 400 WATT M.V.	8.98	
0000388770	LAMP 700 WATT M.V.	37.10	
0000388980	LAMP 1000 WATT MV	46.35	
0000388990	LAMP 70 WATT H.P.S.	8.81	
0000389000	LAMP 100 WATT H.P.S.	8.62	
0000389030	LAMP 135 WATT L.P.S.	44.00	
0000389040	LAMP 150 WATT HPS 100V	25.23	
0000389060	LAMP 150 WATT H.P.S.55V	8.67	
0000389090	LAMP 180 WATT L.P.S.	54.77	
0000389250	LAMP 250 WATT H.P.S.	10.59	
0000389400	LAMP 400 WATT H.P.S.	13.19	
0000389450	LAMP 1000W HPS	60.32	
0000389700	LAMP HALIDE 250W	18.83	
0000389770	LAMP HALIDE 400W	14.93	
0000389810	LAMP HALIDE 1000W	31.31	
0000389900	LAMP STREET LITE SIGNAL	2.21	
0002103270	CONDUIT FLEX BLK 1/2"	4.36	
0050091540	BOLT LAG 1/2"X 4" GALV	0.46	
0050103120	BOLT MACHINE 5/8" X 12"	1.05	
0054223510	CRIMPIT #2/0- #8 WR139	0.55	
0057151000	BRACKET 10'L	101.45	
0057152040	BRACKET 1 1/4"X4' FIXED	60.02	
0057152220	BRACKET 4'X 2' 16" TEN	27.46	
0057154060	BRACKET 1 1/4"X6' LOWER	67.32	
0057155060	BRACKET SWIVEL 1 1/4 X6	18.91	
0057155720	BRACKET TAPERED 6' X 2"	48.90	
0057155723	BRACKET TAPERED 8'	87.05	
0057155725	BRACKET TAPERED 2"X10'	106.44	
0057156020	BRACKET LOWER 2" X 6'	69.88	
0057156080	BRACKET FIXED 2" X 8'	87.48	
0057157010	BRACKET TAPERED 12'L	173.80	
0057158140	PLATE POLE ST LITE 1 1/	9.46	
0057158220	PLATE POLE ST LIGHT 2"	26.24	

SCHEDULE 7

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057350350	LUMINAIRE LPS 135W	463.38	
0057350720	LUM LPS 180W 120/240/347 V	788.99	R04B
0057350750	LUMINAIRE LPS 180W 240V	493.30	XX
0057350800	LUMINAIRE LPS 180W 347V	780.20	XX
0057350830	LUMINAIRE HPS 70W POLY	73.33	XX
0057350835	LUM. 70W POLY C/W LAMP	99.23	XX
0057350836	LUM 70W POLY ALUM.ALLOY	97.70	XX
0057350837	LUMINAIRE 70W HPS CWA ACRYLIC	120.88	C01A
0057350850	LUMINAIRE HPS 70W GLASS	69.32	XX
0057350855	LUM. 70W GLASS C/W LAMP	97.68	C03A
0057350856	LUM 70W GLASS AL. ALLOY	99.37	M12D
0057350857	LUM. 70W GLASS CWI BAL.	120.32	M08A
0057350860	LUM 100W HPS POLY	75.00	XX
0057350865	LUM. 100W POLY C/W LAMP	100.21	XX
0057350866	LUMINAIRE 100W ACRYLIC HPS CWA	124.02	C07A
0057350867	LUM 100W POLY AL. ALLOY	98.37	XX
0057350875	LUM. 100W GLASS C/WLAMP	98.76	XX
0057350877	LUM. 100W GLASS CWI BAL	135.75	XX
0057350880	LUMINAIRE HPS 150W GLAS	82.27	XX
0057350885	LUM. 150W GLASS C/WLAMP	100.95	XX
0057350886	LUMINAIRE 150W HPS CWI GLASS	146.03	M05A
0057350887	LUM. 150W HPS 240V GLAS	150.88	C09A
0057350890	LUMINAIRE HPS 150W POLY	79.24	XX
0057350895	LUM. 150W POLY C/W LAMP	102.95	XX
0057351315	LUMINAIRE 250W HPS CWI GLASS	142.48	C07A
0057351400	LUMINAIRE 250W HPS CWI 347V	160.68	C05A
0057351710	LUMINAIRE HPS 400W GLAS	109.60	XX
0057351715	LUMINAIRE 400W HPS CWI 120/240	157.02	M12A
0057351720	LUMINAIRE HPS 400W 240V	204.30	XX
0057351730	LUMINAIRE HPS 400W 347V	196.00	XX
0057351760	LUMINAIRE 400W 600V HPS CWI GL	172.33	M12A
0057353330	LUMINAIRE MTL-HLDE 400W	281.54	XX
0057353500	LUMINAIRE HALIDE 1000 W	300.00	XX
0057353550	LUMINAIRE HALIDE 1000 W	294.79	T01C
0057400920	AREA LIGHT MV 125 W	107.76	XX
0057401200	LUMINAIRES 70W H-P.S.	107.80	D14B
0057401205	DUSK-T-DAWN 70W HPS CWA	195.17	D08B
0057402020	AREA LIGHT MV 175 W	92.88	XX
0057402100	LUMINAIRES 100W H.P.S.	106.37	XX
0057402105	DUSK-T-DAWN 100W HPS CWA	140.50	C15A
0057402150	FLOODLIGHT 150W HPS CWI	183.39	C17A
0057402240	FLOODLIGHT M.V. 175W	53.03	
0057403330	FLOODLIGHT M V 250 W	397.90	XX
0057403500	FLOODLIGHT 250W HPS CWI	184.41	

SCHEDULE 7

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057404050	FLOODLIGHT M V 400 W	281.17	XX
0057404600	FLOODLIGHT 400W HPS CWI	194.95	C11A
0057408250	FLOODLIGHT MTL HAL.250W	190.30	D05B
0057408500	FLOODLIGHT 400W MTL-HAL CWI	201.63	D03A
0057409000	FLOODLIGHT 1000W MH CWI	405.65	
0057409380	FLOODLIGHT M V 1000 W	439.19	XX
0057600450	BRACKET & ADAPTORS	9.40	
0057601010	CAP SHORTING TWIST LOCK	4.87	
0057601200	CONTROL 120 V PHOTO	7.05	
0057601400	CONTROL ELECT 120V PHOTOCELL	4.52	
0057602000	PHOTO CONTROL 120V HD	19.77	
0057602400	CONTROL 240V ELECT PHOTOCELL	10.96	
0057602960	GUARD WIRE FOR ST-LITE	50.44	
0057603800	REFRACTOR GLASS	32.60	
0057603900	REFRACTORS POLYCARBON #	0.00	
0057604020	REFRACTOR POLY LU B2214	48.03	
0057604050	REFRACTOR POLY LU B2217	73.74	
0057604080	REFRACTOR POLYCARBON #9	21.07	
0057604170	REFRACTOR GLASS	66.37	
0057604200	REFRACTOR ACRYLIC VB15	40.70	
0057604210	REFRACTOR POLY LUM VB15	78.68	
0057604220	REFRACTOR AREA LIGHT	18.99	
0057604240	REFRACTOR GLASS OV15	16.00	
0057604250	REFRACTOR POLY LUM 0V15	24.00	
0057604255	REFRACTOR STREETLIGHT OV	18.12	
0057604270	REFRACTOR GLASS OV25	25.89	
0057604280	REFRACTOR POLY OV25	92.87	
0057604300	REFRACTOR GLASS OV50	17.50	
0057605800	REDUCER LAMPHOLDER,	6.25	
0057606100	REFRACTOR 125 W M V	34.36	
0057606500	REFRACTOR FOR SODIUM	71.31	
0057606550	REFRACTOR FOR SODIUM	88.62	
0057606700	REFRACTOR 250 W M V	38.69	
0057606950	REFRACTOR 400 W M V	33.01	
0057607300	RELAY 30 AMP 110 V MURC	33.89	
0057607330	RELAY 30 AMP 125 V	140.04	
0057607400	RELAY 60 AMP 115 V	214.85	
0057607440	RELAY 60 AMP 250 V	191.29	
0057608690	STARTERS HPS LUMINAIRES	31.63	
0057608700	STARTER FOR HPS 70-150W	40.95	
0057608703	STARTER FOR HPS 55V	41.17	
0057608710	STARTER FOR SODIUM	40.41	
0057608713	STARTER KIT HPS 55V 70/	31.75	
0057608720	STARTER FOR HPS 150-400	40.76	

SCHEDULE 7

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2011	Location
0057608722	STARTER FOR HPS 100V	36.35	
0057608730	STARTER FOR SODIUM	48.16	
0065734220	CABLE CU ST-LITE 2C #12	1.03	

SCHEDULE 8

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY
LAMP LIFE ANALYSIS
September 2005

Assumptions: Total annual photocell operating time is based on 4,000 hours per year or 333 hours per month.
All Average Rated Life Spans are as indicated in the IES Lighting Handbook, 1981 Edition
(IES = Illuminating Engineering Society)

Lamp Type	Average Life (Hrs)	Burning Hours per Year	Service Life (Years)	Life Relative to 100W HPS	Replacements Relative to 100W HPS
Incandescent	2500	4000	0.6	0.10	9.60
Flourescent (48 in., T12, Recess Base)	12000	4000	3.0	0.50	2.00
Mercury Vapour	24000	4000	6.0	1.00	1.00
Mercury Vapour 125W *See Note	18000	4000	4.5	0.75	1.33
Metal Halide 175W	7500	4000	1.9	0.31	3.20
Metal Halide 250W	10000	4000	2.5	0.42	2.40
Metal Halide 400W	15000	4000	3.8	0.63	1.60
Metal Halide 1000W	10000	4000	2.5	0.42	2.40
High Pressure Sodium 70W	24000	4000	6.0	1.00	1.00
High Pressure Sodium 100W	24000	4000	6.0	1.00	1.00
Low Pressure Sodium	8000	4000	2.0	0.33	3.00

*** No Average life data was available for this lamp size in the references listed above. 75% of the quoted life for all Mercury Lamps was used.**

Nova Scotia Power Inc. **Schedule 9**
LED Streetlights
2014 Rate Stabilization
CCA Schedule
Millions of dollars

		1	2	3	4	5	6	7	8	9
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
		12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020
Beginning UCC										
	8%	-	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320
		-	**-**	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**
Additions										
	8%		16,924,872	17,322,621	-	-	-	-	-	-
		-	**16,924,872**	**17,322,621**	**-**	**-**	**-**	**-**	**-**	**-**
CCA										
	8%	-	676,995	1,992,735	2,526,221	2,324,123	2,138,193	1,967,138	1,809,767	1,664,986
		-	**676,995**	**1,992,735**	**2,526,221**	**2,324,123**	**2,138,193**	**1,967,138**	**1,809,767**	**1,664,986**
Ending UCC										
	8%	-	16,247,877	31,577,763	29,051,542	26,727,419	24,589,225	22,622,087	20,812,320	19,147,335
		-	**16,247,877**	**31,577,763**	**29,051,542**	**26,727,419**	**24,589,225**	**22,622,087**	**20,812,320**	**19,147,335**
	Tax Rate:	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	Tax Savings from CCA :	-	209,868	617,748	783,129	720,478	662,840	609,813	561,028	516,146

Nova Scotia Power Inc. **Schedule 9**
LED Streetlights
2014 Rate Stabilization
CCA Schedule
Millions of dollars

	10	11	12	13	14	15	16	17	18	19	20
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	12/31/2021	12/31/2022	12/31/2023	12/31/2024	12/31/2025	12/31/2026	12/31/2027	12/31/2028	12/31/2029	12/31/2030	1/1/2031
Beginning UCC											
	19,147,335	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381
	19,147,335	**17,615,548**	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**
Additions											
	-	-	-	-	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
CCA											
	1,531,787	1,409,244	1,296,504	1,192,784	1,097,361	1,009,572	928,807	854,502	786,142	723,251	665,390
	1,531,787	**1,409,244**	**1,296,504**	**1,192,784**	**1,097,361**	**1,009,572**	**928,807**	**854,502**	**786,142**	**723,251**	**665,390**
Ending UCC											
	17,615,548	16,206,304	14,909,800	13,717,016	12,619,654	11,610,082	10,681,276	9,826,773	9,040,632	8,317,381	7,651,991
	17,615,548	**16,206,304**	**14,909,800**	**13,717,016**	**12,619,654**	**11,610,082**	**10,681,276**	**9,826,773**	**9,040,632**	**8,317,381**	**7,651,991**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%
	474,854	436,866	401,916	369,763	340,182	312,967	287,930	264,896	243,704	224,208	206,271

Nova Scotia Power Inc.
LED Streetlights
2014 Rate Stabilization
CCA Schedule
Millions of dollars

Schedule 9

	21	22	23	24	25	26	27	
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	
	1/2/2031	1/3/2031	1/4/2031	1/5/2031	1/6/2031	1/7/2031	1/8/2031	**Total**
Beginning UCC								
	7,651,991	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	**357,611,954**
	7,651,991	**7,039,831**	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**357,611,954**
Additions								
	-	-	-	-	-	-	-	
	-	**-**	**-**	**-**	**-**	**-**	**-**	**34,247,493**
CCA								
	612,159	563,187	518,132	476,681	438,547	403,463	371,186	**29,978,856**
	612,159	**563,187**	**518,132**	**476,681**	**438,547**	**403,463**	**371,186**	**29,978,856**
Ending UCC								
	7,039,831	6,476,645	5,958,513	5,481,832	5,043,286	4,639,823	4,268,637	**361,880,591**
	7,039,831	**6,476,645**	**5,958,513**	**5,481,832**	**5,043,286**	**4,639,823**	**4,268,637**	**361,880,591**
	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	**8**
	189,769	174,588	160,621	147,771	135,949	125,073	115,068	**9,293,445**

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent :														
Incandescent < 300 Watts - Note 1	001	97	$14.70	5.09	$1.88	$21.67	$7,020	$19.61	10.5%	27	$668	0.291	7.857	
Incandescent > 300 Watts - Note 1	002	154	23.34	5.09	2.00	$30.43	730	$27.78	9.5%	2	64	0.462	0.924	
Incandescent < 300 Watts - Note 1	003	97	14.70	0.00	0.00	$14.70	1,235	$13.72	7.1%	7	82	0.291	2.037	
							8,985			36	814			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43	6.53	5.09	3.19	$14.81	33,526	$13.18	12.4%	189	3,699	0.129	24.335	
Mercury Vapour 125 Watts	101	52	7.87	6.79	2.99	$17.65	1,647,324	$15.61	13.1%	7,778	190,317	0.156	1,213.339	
Mercury Vapour 175 Watts	102	69	10.44	5.09	2.97	$18.50	412,677	$16.65	11.1%	1,859	41,197	0.207	384.884	
Mercury Vapour 250 Watts	103	97	14.70	5.09	3.68	$23.47	201,737	$21.27	10.4%	716	18,934	0.291	208.423	
Mercury Vapour 400 Watts	104	154	23.34	5.09	3.76	$32.19	268,846	$29.40	9.5%	696	23,294	0.462	321.523	
Mercury Vapour 700 Watts	105	260	39.41	5.09	4.94	$49.44	6,526	$45.48	8.7%	11	523	0.780	8.580	
Mercury Vapour 1000 Watts	106	363	55.03	5.09	5.97	$66.09	68,206	$60.99	8.4%	86	5,267	1.089	93.654	
Mercury Vapour 250 Watt Cont. Oper.	107	212	24.96	10.18	3.68	$38.82	1,398	$34.87	11.3%	3	142	0.291	0.873	0.873
Mercury Vapour 125 Watts	201	52	7.87	6.79	0.00	$14.66	1,231	$12.73	15.1%	7	161	0.156	1.092	
Mercury Vapour 175 Watts	202	69	10.44	5.09	0.00	$15.53	3,913	$13.80	12.5%	21	436	0.207	4.347	
Mercury Vapour 250 Watts	203	97	14.70	5.09	0.00	$19.79	8,311	$17.76	11.4%	35	853	0.291	10.185	
Mercury Vapour 400 Watts	204	154	23.34	5.09	0.00	$28.43	3,070	$25.82	10.1%	9	282	0.462	4.158	
Mercury Vapour 700 Watts	205	260	39.41	5.09	0.00	$44.50	0	$40.81	9.0%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363	55.03	5.09	0.00	$60.12	15,871	$55.37	8.6%	22	1,254	1.089	23.958	
Mercury Vapour 125 Watts	301	52	7.87	0.00	0.00	$7.87	1,039	$7.35	7.1%	11	69	0.156	1.716	
Mercury Vapour 175 Watts	302	69	10.44	0.00	0.00	$10.44	19,669	$9.76	7.0%	157	1,281	0.207	32.499	
Mercury Vapour 250 Watts	303	97	14.70	0.00	0.00	$14.70	9,526	$13.72	7.1%	54	635	0.291	15.714	
Mercury Vapour 400 Watts	304	154	23.34	0.00	0.00	$23.34	4,201	$21.78	7.2%	15	281	0.462	6.930	
Mercury Vapour 700 Watts	305	260	39.41	0.00	0.00	$39.41	473	$36.77	7.2%	1	32	0.780	0.780	
Mercury Vapour 1000 Watts	306	363	55.03	0.00	0.00	$55.03	4,623	$51.33	7.2%	7	311	1.089	7.623	
							2,712,168			11,677	288,968			

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30	4.56	10.18	2.42	$17.16	184,731	$14.67	17.0%	897	26,857	0.091	81.627	
Fluorescent 2x48" 220 Watts	111	85	12.89	10.18	2.68	$25.75	35,219	$22.68	13.5%	114	4,193	0.254	28.956	
Fluorescent 2x72" 300 Watts	112	116	17.60	10.18	3.14	$30.92	24,860	$27.49	12.5%	67	2,759	0.348	23.316	
Fluorescent 4x72" 600 Watts	113	222	33.63	10.18	4.29	$48.09	8,657	$43.53	10.5%	15	821	0.665	9.975	
Fluorescent 1x96" 110 Watts	114	47	7.11	10.18	2.96	$20.24	1,215	$17.57	15.2%	5	161	0.141	0.705	
Fluorescent 1x72" 150 Watts	115	60	9.10	10.18	2.57	$21.85	262	$19.04	14.7%	1	34	0.180	0.180	
Fluorescent 4x48" 440 Watts	116	166	25.18	10.18	3.24	$38.60	926	$34.65	11.4%	2	95	0.499	0.998	
							255,870			1,101	34,920			
Fluorescent 4x72" 600 Watts	213	222	33.63	10.18	0.00	$43.81	0	$39.46	11.0%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47	7.11	10.18	0.00	$17.29	5,394	$14.72	17.4%	26	800	0.141	3.666	
Fluorescent 1x72" 150 Watts	215	60	9.10	10.18	0.00	$19.28	694	$16.55	16.4%	3	98	0.180	0.540	
Fluorescent 4x48" 440 Watts	216	166	25.18	10.18	0.00	$35.36	*0*	$31.54	12.1%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49	7.41	10.18	0.00	$17.59	211	$15.00	17.2%	1	31	0.146	0.146	
Fluorescent 2x48" 220 Watts	218	85	12.89	10.18	0.00	$23.07	0	$20.09	14.8%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47	7.11	0.00	0.00	$7.11	171	$6.65	6.9%	2	11	0.140	0.280	
							6,469			32	940			
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486	57.20	0.00	0.00	$57.20	686	$53.36	7.2%	1	46	0.665	0.665	0.665
Fluorescent 2x24" 70 Watts	118	66	7.76	0.00	0.00	$7.76	1,583	$7.25	7.0%	17	104	0.091	1.547	1.547
Fluorescent 4x48" 440 Watts	119	364	42.86	0.00	0.00	$42.86	11,829	$39.97	7.2%	23	798	0.499	11.477	11.477
Fluorescent 2x96"	120	254	29.91	0.00	0.00	$29.91	10,768	$27.89	7.2%	30	727	0.348	10.440	10.440
Fluorescent 4x96"	150	613	72.16	0.00	0.00	$72.16	18,184	$67.31	7.2%	21	1,222	0.840	17.640	17.640
							43,051			92	2,897			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30	4.56	0.00	0.00	$4.56	109	$4.24	7.5%	2	8	0.091	0.182	
Fluorescent 4x48" 440 Watts	311	166	25.18	0.00	0.00	$25.18	1,511	$23.47	7.3%	5	103	0.499	2.495	
Fluorescent 2x72" 300 Watts	312	116	17.60	0.00	0.00	$17.60	211	$16.40	7.3%	1	14	0.348	0.348	
Fluorescent 4x72" 600 Watts	313	222	33.63	0.00	0.00	$33.63	0	$31.39	7.1%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47	7.11	0.00	0.00	$7.11	2,133	$6.65	6.9%	25	138	0.142	3.550	
Fluorescent 1x72" 150 Watts	315	60	9.10	0.00	0.00	$9.10	0	$8.48	7.3%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280	42.46	0.00	0.00	$42.46	38,724	$39.59	7.2%	76	2,617	0.841	63.916	
							42,688			109	2,880			

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60	9.10	15.27	5.78	$30.14	14,408	$26.03	15.8%	40	1,965	0.180	7.170	
Low Pressure Sodium 180 Watts	131	80	12.13	15.27	8.37	$35.76	156,422	$31.25	14.5%	365	19,752	0.240	87.481	
Low Pressure Sodium 90 Watts	132	45	6.81	15.27	5.78	$27.85	0	$23.91	16.5%	0	0	0.135	0.000	
Low Pressure Sodium 180 Watts E&M	231	80	12.13	15.27	0.00	$27.40	12,821	$23.42	17.0%	39	1,860	0.240	9.360	
Low Pressure Sodium 180 Watts E/O	331	80	12.13	0.00	0.00	$12.13	5,386	$11.31	7.3%	37	364	0.240	8.880	
							189,037			480	23,941			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100	15.16	5.09	3.21	$23.46	913,277	$21.25	10.4%	3,244	85,867	0.300	973.336	
High Pressure Sodium 400 Watts	122	150	22.74	5.09	3.32	$31.15	817,586	$28.43	9.6%	2,187	71,505	0.450	984.158	
High Pressure Sodium 70 Watts	123	32	4.84	5.09	3.02	$12.95	4,200,493	$11.46	12.9%	27,040	480,331	0.096	2,595.850	
High Pressure Sodium 100 Watts	124	45	6.81	5.09	3.04	$14.94	5,846,781	$13.32	12.2%	32,612	634,870	0.135	4,402.640	
High Pressure Sodium 150 Watts	125	65	9.85	5.09	3.22	$18.16	858,139	$16.31	11.3%	3,939	87,259	0.195	768.083	
HP Sodium 100 Watts - Cont. Oper.	126	99	11.63	10.18	3.04	$24.85	4,473	$21.87	13.6%	15	537	0.135	2.025	2.025
High Pressure Sodium 250 Watts	221	100	15.16	5.09	0.00	$20.25	41,550	$18.18	11.4%	171	4,251	0.300	51.300	
High Pressure Sodium 70 Watts	222	32	4.84	5.09	0.00	$9.93	30,739	$8.57	15.9%	258	4,215	0.096	24.768	
High Pressure Sodium 100 Watts	223	45	6.81	5.09	0.00	$11.90	19,276	$10.40	14.4%	135	2,432	0.135	18.225	
High Pressure Sodium 150 Watts	224	65	9.85	5.09	0.00	$14.94	41,231	$13.23	12.9%	230	4,724	0.195	44.850	
High Pressure Sodium 250 Watts	321	100	15.16	0.00	0.00	$15.16	175,371	$14.14	7.2%	964	11,799	0.300	289.200	
High Pressure Sodium 70 Watts	322	32	4.84	0.00	0.00	$4.84	347,202	$4.53	6.8%	5,978	22,238	0.096	573.888	
High Pressure Sodium 100 Watts	323	45	6.81	0.00	0.00	$6.81	194,248	$6.36	7.1%	2,377	12,836	0.135	320.895	
High Pressure Sodium 150 Watts	324	65	9.85	0.00	0.00	$9.85	14,775	$9.19	7.2%	125	990	0.195	24.375	
High Pressure Sodium 400 Watts	326	150	22.74	0.00	0.00	$22.74	24,286	$21.21	7.2%	89	1,634	0.450	40.050	
High Pressure Sodium 500 Watts	327	183	27.75	0.00	0.00	$27.75	999	$25.88	7.2%	3	67	0.550	1.650	
High Pressure Sodium 1000 Watts	328	363	55.04	0.00	0.00	$55.04	9,247	$51.33	7.2%	14	623	1.090	15.260	
High Pressure Sodium 1500 Watts	329	500	75.80	0.00	0.00	$75.80	910	$70.70	7.2%	1	61	1.090	1.090	
							13,540,585			79,383	1,426,178			

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150	22.74	8.14	3.80	$34.68	379,383	$31.29	10.8%	912	37,117	0.450	410.235	
Metallic Arc 1000 Watts	141	360	54.57	12.21	5.55	$72.33	851,509	$65.83	9.9%	981	76,548	1.080	1,059.480	
Metallic Arc 250 Watts	142	100	15.16	12.21	3.74	$31.11	27,687	$27.39	13.6%	74	3,310	0.300	22.248	
Metallic Arc 150 Watts	143	67	10.15	12.21	3.74	$26.10	1,253	$22.72	14.9%	4	162	0.200	*0.800*	
Metallic Arc 100 Watts	144	50	7.58	12.21	3.74	$23.53	1,231	$20.32	15.8%	4	168	0.150	0.654	
Metallic Arc 1000 Watts	341	360	54.57	0	0	$54.57	14,406	$50.91	7.2%	22	966	1.080	23.760	
Metallic Arc 400 Watts	342	150	22.74	0	0	$22.74	43,388	$21.21	7.2%	159	2,919	0.450	71.550	
Metallic Arc 250 Watts	343	100	15.16	0	0	$15.16	15,281	$14.14	7.2%	84	1,028	0.300	25.200	
Metallic Arc 175 Watts	344	75	11.37	0	0	$11.37	15,281	$10.61	7.2%	112	1,021	0.225	25.200	
Metallic Arc 150 Watts	345	67	10.15	0	0	$10.15	2,436	$9.47	7.2%	20	163	0.200	4.000	
Metallic Arc 100 Watts	346	50	7.58	0	0	$7.58	0	$7.07	7.2%	0	0	0.150	0.000	
							1,351,856			2,372	123,402			
Light Emitting Diode - Traffic Lights														
Light Emitting Diode 4.6 Watts	530	3	0.36	0	0	$0.36	$0.00	$0.34	6.2%		0		0.000	
Light Emitting Diode 7.5 Watts	531	5	0.63	0	0	$0.63	$0.00	$0.58	7.9%		0		0.000	
Light Emitting Diode (Energy Only)														
Lighting Emitting Diode 44 Watts	532	15	2.27	0	0	$2.27	47,180	$2.12	7.1%	1,732	3,118	0.440	762.080	
Lighting Emitting Diode 66 Watts	533	22	3.34	0	0	$3.34	5,531	$3.11	7.4%	138	381	0.660	91.080	
Lighting Emitting Diode 88 Watts	534	29	4.40	0	0	$4.40	27,086	$4.10	7.3%	513	1,847	0.880	451.440	
Lighting Emitting Diode 92 Watts	535	31	4.70	0	0	$4.70	0	$4.38	7.3%	0	0	0.920	0.000	
Lighting Emitting Diode 105 Watts	536	35	5.31	0	0	$5.31	0	$4.95	7.3%	0	0	0.105	0.000	
Lighting Emitting Diode 170 Watts	537	57	8.64	0	0	$8.64	0	$8.06	7.2%	0	0	0.170	0.000	
Lighting Emitting Diode 110 Watts	539	37	5.61	0	0	$5.61	175,638	$5.23	7.3%	2,609	11,897	0.110	286.990	
Lighting Emitting Diode 65 Watts	540	22	3.34	0	0	$3.34	18,597	$3.11	7.4%	464	1,281	0.650	301.600	
Lighting Emitting Diode 55 Watts	541	18	2.73	0	0	$2.73	24,111	$2.55	7.1%	736	1,590	0.550	404.800	
Lighting Emitting Diode 83 Watts	542	28	4.24	0	0	$4.24	52,864	$3.96	7.1%	1,039	3,491	0.830	862.370	
Lighting Emitting Diode 48 Watts	543	16	2.43	0	0	$2.43	2,100	$2.26	7.5%	72	147	0.830	59.760	
Lighting Emitting Diode 72 Watts	544	24	3.64	0	0	$3.64	13,453	$3.39	7.4%	308	924	0.830	255.640	
							366,561			7,611				

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Light Emitting Diode (Energy & Capital														
LED A1	615	15	2.27	0	8.30	$10.57	1,529,817	$10.18	3.8%	12,056	56,694	0.830	10,006.569	
LED A2	616	18	2.73	0	8.30	$11.03	456,253	$10.61	4.0%	3,446	17,444	0.830	2,859.951	
LED A4	617	25	3.79	0	8.30	$12.09	119,481	$11.60	4.2%	823	4,859	0.830	683.308	
LED A3	618	29	4.40	0	8.30	$12.70	2,689	$12.16	4.5%	18	115	0.830	14.638	
LED B1	619	22	3.34	0	8.30	$11.64	2,018,611	$11.17	4.2%	14,446	81,803	0.830	11,990.483	
LED C1	620	29	4.40	0	8.30	$12.70	338,830	$12.16	4.5%	2,223	14,452	0.830	1,844.711	
LED C3	621	37	5.61	0	8.30	$13.91	280,535	$13.29	4.7%	1,680	12,538	0.830	1,394.512	
LED C2	622	58	8.79	0	8.30	$17.09	301,781	$16.26	5.1%	1,471	14,686	0.830	1,221.061	
							5,047,996			36,163				
TOTALS							**$23,565,266**			**139,056**			**49,016.734**	**44.667**
										102,893				

Non LED	**95,282**
LED	**43,774**
Total	**139,056**
Non LED	
Energy Only	83,885
Maintenance	957
Capital	10,440
Total	95,282
LED	
Energy Only	7,611
Capital	36,163
Total	43,774
Grand Total	139,056

SCHEDULE 10

2014 Rate Stabilization - STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2014

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2014 New Proposed Rates	2014 New Proposed Revenue	2013 Current Rates	Percent Change	2014 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)

Count = 93

Note 1 - Red highligted P&E charges relate to calculated rounding differences using Misc. Small Loads Tariff.
Note 2 - Incandescent rates were set at 250W and 400W Mercury Vapour

Miscellaneous Small Loads Rate		
Demand Charge	$/kW	**10.963**
Block 1 Energy		
Base cost of fuel	¢/kWh	4.876
Non-fuel	¢/kWh	7.661
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 1 (first 200kWh *	¢/kWh	**12.537**
Block 2 Energy		
Base cost of fuel	¢/kWh	4.876
Non-fuel	¢/kWh	3.448
AA	¢/kWh	-
BA	¢/kWh	-
Total Energy Charge, block 2	¢/kWh	**8.324**

Calculation of Power & Energy Rate :
Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

Photocell Operation (4000 burning hours per year)			
Demand Charge $/kW (annual)		11.753	$141.03
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.13440	322.56
2nd Block : All additional (annual)	1,600	0.08924	142.78
			$606.38
Rate per kW.h	4,000		**$0.1515944**
Continuous Burning (8760 burning hours per year)			
Demand Charge $/kW (annual)		11.753	$141.03
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.13440	322.56
2nd Block : All additional (annual)	6,360	0.08924	567.57
			$1,031.16
Rate per kW.h	8,760		**$0.1177123**

Proposed Rates

2013 Tariffs - Rate Stabilization

DOMESTIC SERVICE TARIFF
Rate Codes 02, 03, 04

CUSTOMER CHARGE

$10.83 per month

ENERGY CHARGE

13.511 cents per kilowatt hour

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing “blocks” of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer’s normal bill for service taken under the Domestic Service rate.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06

CUSTOMER CHARGE

$18.82 per month

ENERGY CHARGE

December, January and February

07:00 am to 12:00 pm	17.603 cents per kilowatt hour
12:00 pm to 04:00 pm	13.511cents per kilowatt hour
04:00 pm to 11:00 pm	17.603 cents per kilowatt hour
11:00 pm to 07:00 am	6.928 cents per kilowatt hour

The above rates apply weekdays (Monday to Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 6.928 cents per kilowatt hour.

March to November

07:00 am to 11:00 pm	13.511 cents per kilowatt hour
11:00 pm to 07:00 am	6.928 cents per kilowatt hour

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 6.928 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06

Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

SMALL GENERAL TARIFF
Rate Code 10

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

14.307 cents per kilowatt hour for the first 200 kilowatt hours per month

12.587 cents per kilowatt hour for all additional kilowatt hours

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable.

GENERAL TARIFF
Rate Code 11

DEMAND CHARGE

$9.935 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

10.608 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand.

7.505 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

DEMAND CHARGE

$12.526 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

7.536 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

(3) The Company reserves the right to have a separate service and/or operating agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

DEMAND CHARGE

$7.285 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

9.529 cents per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand.

7.278 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering.

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

MEDIUM INDUSTRIAL TARIFF
(250 kVA or 225 kW – 1,999 kVA or 1,799 kW)
Rate Code 22

DEMAND CHARGE

$11.769 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

6.817 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$11.177 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

6.799 cents per kilowatt hour

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating a telephone call to send notice to the customer's dedicated telephone number requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's dedicated telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall

be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

MUNICIPAL TARIFF

DEMAND CHARGE

$11.775 per month per kilovolt ampere of the higher of:

a) maximum actual demand of the current month or

b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

7.133 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

LOAD RETENTION TARIFF

DEMAND CHARGE

To be determined as specified in Special Condition (1).

ENERGY CHARGE

To be determined as specified in Special Condition (1).

AVAILABILITY

(1) This rate shall be granted only in circumstances where it can be shown that:

- The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible, or the rate is required to respond to the competitive challenge of business closure due to economic distress; and
- Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question; and
- The revenue from service to a customer under this rate shall be greater than the applicable incremental cost to serve such customer and shall make a significant positive contribution to fixed costs.

The procedure for establishing that this test is satisfied is outlined in Attachment A.

(2) This rate shall be available only to customers who have a minimum load of and/or who are considering an alternate supply of at least 2000 KVA or 1800 KW. Where the rate is required to respond to the competitive challenge of business closure due to economic distress this rate shall be available only to Extra-Large Industrial customers.

(3) The customer shall apply in writing to take service under this rate.

(4) This rate shall be available only to customers whose electricity needs, at the date of application, are being supplied by NSPI and have been supplied by NSPI for at least two consecutive years at the time of the request. It is not available for new load.

MINIMUM LOAD REQUIREMENT

All customers must agree to maintain a minimum level of load while taking service under the rate, subject to (i) any terms or conditions relating to supply interruption that may be outlined in the pricing conditions of the rate, (ii) the customer's requirement to take downtime for maintenance purposes and (iii) market downtime, labour disruption and other matters beyond the reasonable control of the customer.

SECURITY FOR PAYMENT OF ACCOUNT

A customer taking service under this rate must provide security for payment of the customer's account, regardless of payment history. Appropriate security shall be satisfactory to Nova Scotia Power Inc. Acceptable security will be described in the pricing of the rate, and may be revised or updated from time to time upon approval of the UARB.

DISCONNECTION OF ELECTRIC SERVICE

In the event of non-payment, NSPI may disconnect a customer on two business days' notice. In the event of a dispute under the tariff, the complaint will be made directly to the Board for resolution, as opposed to the Dispute Resolution Officer.

SPECIAL CONDITIONS

(1) The price, terms and conditions (including any modification in special conditions associated with the rate(s) under which the customer purchased power and energy prior to taking service under this rate) shall be established jointly by NSPI and the customer, following the procedure outlined in Attachment A.

(2) The price, terms and conditions offered under this rate shall be determined on a customer by customer basis.

(3) The price, terms and conditions offered under this rate shall be submitted by NSPI to the UARB for approval.

ATTACHMENT A

This attachment outlines procedures by which the requirements of Availability Clause (1) and Special Condition (1) are to be satisfied.

(1) The customer shall apply in writing to take service under this rate, outlining the available alternate supply option or the potential for closure due to economic distress and the rationale for seeking service under the load retention rate.

(2) Upon written application by a customer to take service under this rate which meets the requirements of clause (1) above, the UARB shall direct that NSPI conduct a screening to determine whether the implementation of these procedures is warranted.

(3) Subject to (2), NSPI and the customer shall proceed to implement these procedures and establish a load retention price, with appropriate terms and conditions.

(4) Should there be disagreement between NSPI and the customer with respect to the decision to proceed, the customer may ask the UARB to adjudicate.

(5) These procedures shall be applied on a customer by customer basis.

(6) To protect confidential NSPI and customer data, none of the data or analysis used in the implementation of these procedures, nor any results thereof, including the recommended price, terms and conditions, shall be required to be publicly disclosed.

(7) The economic feasibility of the customer's option to supply some or all of its own load shall be established where it can be shown that under reasonable assumptions the cost of electricity to the customer from that option is expected to be lower than the cost to the customer of continuing to purchase electricity from NSPI.

(8) The cost to the customer of the alternate supply shall reflect all appropriate factors, including but not limited to:

- Capital costs
- Fixed and Variable Operating costs
- Fuel costs (short and long term, contracts, etc.)
- Ancillary Services costs (electric)
- Steam production and steam backup costs (where appropriate)
- Contributions-in-aid of construction (where NSPI's system must be modified to accommodate the customer's generator)
- Expected Service Life
- Salvage Value
- Electric sales/purchases (where the customer's generator output does not match customer requirements)
- Depreciation and/or Capital Cost Allowance
- Taxes
- Appropriate return

LOAD RETENTION TARIFF

(9) The technical feasibility of the customer's alternate supply shall reflect all appropriate factors, including but not limited to:

- Technology maturity and proven performance level
- Site specific considerations (space requirements, availability of cooling water, fuel handling, etc.)
- Environmental acceptability (air emissions, solid waste management, etc.)
- Modifications to NSPI's transmission and/or distribution system to accommodate the new generation and/or to supply ancillary services.
- Metering systems
- Where cogen is involved, compatibility of steam versus electric requirements.

(10) If the customer is applying for a load retention rate on the basis of economic distress, the customer shall provide NSPI and the UARB proof of economic distress, the adequacy of which shall be determined by the UARB prior to approving any proposed rate, including:

- Current and historical financial information for a minimum of at least three (3) fiscal years of the customer
- Evidence of activities undertaken by the customer in the last three (3) years to reduce costs
- Affidavit of a senior executive of the customer or its parent indicating the need for the requested load retention rate. Whether the affidavit is provided by an executive of the customer or the parent must be consistent with whether it will be the customer or parent who will make the decision to leave NSPI's system in the absence of the load retention rate. Further the affidavit should include
    - An analysis of the market in which the customer operates
    - Identification of the factors other than electricity costs that are contributing to the economic hardship
    - The customer's plan to address the above factors
    - An estimate of the electricity price that could alleviate the economic hardship
    - An estimate of the probability that the customer will leave NSPI's system if the requested load retention rate is not granted

- Such other information as reasonably requested by NSPI or the UARB.

(11) The impact on NSPI's other customers of losing the customer load in question, shall be determined using NSPI's forecasting and planning models (as appropriate) to compare scenarios that include either the customer's move to an alternate supply or cessation of operations, as the case may be, with scenarios that assume the customer continues to be supplied by NSPI.

(12) Where the impact on NSPI's other customers can be mitigated by offering the customer

in question a load retention rate, NSPI and the customer shall determine an appropriate rate for the customer. This shall include the price (which may be formula-driven), and any other terms and conditions, including (where relevant) a suggested term and any appropriate renewal guidelines.

LOAD RETENTION TARIFF PRICING MECHANISM

AVAILABILITY:

1. This Load Retention Pricing Mechanism (Pricing Mechanism) is available to, Bowater Mersey Paper Company Ltd (Bowater) for energy other than presently served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this Pricing Mechanism must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF tariff customers, and in advance of Interruptible Rider customers.

4. This Pricing Mechanism cannot be taken in conjunction with other Tariffs, except for the ability of Bowater to take energy under the Mersey Agreement.

RATE MECHANISM:

The intent of this rate is to create a mechanism whereby customers on the rate pay the variable incremental costs of service, plus a significant positive contribution to fixed costs, such that other customers are better off by retaining the customers rather than having the customers depart the system and make no contribution to fixed cost recovery.

LOAD RETENTION TARIFF PRICING MECHANISM

CHARGES:

Energy Charge

The Energy Charge shall be as follows:

Year (January 1 to December 31)	Variable Incremental Rate (cents per kWh)	Contribution (cents per kWh) fixed costs	Energy charge (cents per kWh)
2012	5.624	0.4	6.024
2013	6.177	0.4	6.577
2014	6.386	0.4	6.786

RE-OPENER CLAUSE

The UARB reserves the right to adjust the above rates on a prospective basis if actual costs significantly vary from Load Retention Rate assumptions. Following any adjustment, the customer would be provided the opportunity to determine whether to remain on the rate.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) is applicable to the Tariff for the 2012 rate year only. For 2012, the rate applicable to the Extra Large Industrial Two Part Real Time Pricing Tariff (ELI 2P-RTP) approved by the UARB pursuant to the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge in 2012.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the ELI 2P-RTP Tariff for the 2012 rate year on account of fuel and purchased power costs incurred in 2010 and 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2012 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2012.

The ELI 2P-RTP portion of the FAM BA (in cents per kilowatt hour) for the 2013 rate year on account of fuel and purchased power costs incurred in 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2013 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2013.

No other FAM charges shall be applicable to this Tariff.

LOAD RETENTION TARIFF PRICING MECHANISM

SPECIAL CONDITIONS:

Major Scheduled Maintenance Periods

The customer will annually provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

Day Ahead Forecast

The customer shall supply NSPI, by 0800 hours each day, a 24 hour forecast for the following day of the customer's hourly requirements in MW.

Minimum Load Requirement:

The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a regular demand of 25 000 kVA.

Supply Interruption:

This Pricing Mechanism is interruptible for supply reasons. The customer will reduce its subscribed interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating a telephone call to send notice to the customer requiring such reduction. Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes. The customer must maintain a telephone number and telephone system in working order at all times and must have a designated staff person to answer the telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider

Supply Interruption calls will be made to all customers taking energy pursuant to this Pricing Mechanism on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the cost of the applicable billing for energy taken under this tariff effective at that time for the consumption used in that billing month.

LOAD RETENTION TARIFF PRICING MECHANISM

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + (($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A"

The total penalty will not exceed two times the cost of the appropriate billing effective at that time for the consumption used in that billing month.

Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to the company so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to Interruptible service in the future, the customer may convert to interruptible service following two (2) years service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GR&LF) Rate;
2. Load Retention Tariff Pricing Mechanism;
3. Interruptible Rider to the Large Industrial Rate.

LOAD RETENTION TARIFF PRICING MECHANISM

Maintain System Integrity

The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic Voltage and current levels, Voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

Security for Payment of Account

The customer shall make weekly payments on account of its estimated monthly billings from NSPI. NSPI shall provide the customer with a reasonable estimated weekly billing for each week (Monday through Sunday, prorated for the first and last week, or such other weekly period as the customer and NSPI may agree) during the term. Prior to close of business each Thursday immediately following a billing week (or as otherwise subsequently agreed), the customer shall make a payment by wire transfer to NSPI’s account equal to that prior week’s estimated amount as provided by NSPI. If NSPI does not provide the applicable weekly estimate to the customer in advance of the Thursday payment requirement, the customer shall make payment in accordance with the immediately prior estimate. At the end of each month the customer shall, as applicable, make an additional payment or receive a credit towards its next payment in order to balance its account to actual prior month’s usage.

Separate Service Agreement

The Company reserves the right to have a separate service agreement if, in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

LOAD RETENTION TARIFF PRICING MECHANISM

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

Metering Costs

Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

OUTDOOR RECREATIONAL LIGHTING TARIFF
Rate Code 41

ENERGY CHARGE

14.374 cents per kilowatt hour for all metered kilowatt hours per month.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatthour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

UNMETERED SERVICE RATES

(A) STREET AND AREA LIGHTING

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in Cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

RATES

(1) **INCANDESCENT**

Rate Code	**Watts**	**kWh/Mo.**	**$/Mo.**	**Other**
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$19.61	
002	Greater than 300	154	27.78	
b) Operating Only				
003	300 and Less	97	13.72	

UNMETERED SERVICE RATES

(2) **MERCURY VAPOUR**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$13.18	
101	125	52	15.61	
102	175	69	16.65	
103	250	97	21.27	
104	400	154	29.40	
105	700	260	45.48	
106	1000	363	60.99	
107	250	212	34.87	Continuous Operation
b) Operating and Maintenance Only				
201	125	52	$12.73	
202	175	69	13.80	
203	250	97	17.76	
204	400	154	25.82	
205	700	260	40.81	
206	1000	363	55.37	
c) Operating Only				
301	125	52	$7.35	
302	175	69	9.76	
303	250	97	13.72	
304	400	154	21.78	
305	700	260	36.77	
306	1000	363	51.33	

UNMETERED SERVICE RATES

(3) **FLUORESCENT**

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)					
110	24	2	30	$14.67	
111	48	2	85	22.68	
112	72	2	116	27.49	
113	72	4	222	43.53	
114	96	1	47	17.57	
115	72	1	60	19.04	
116	48	4	166	34.65	
b) Operating and Maintenance Only					
213	72	4	222	$39.46	
214	96	1	47	14.72	
215	72	1	60	16.55	
216	48	4	166	31.54	
217	48	1	49	15.00	
218	48	2	85	20.09	
c) Operating Only					
330	35	4	47	6.65	

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

117	72	4	486	$53.36
118	24	2	66	7.25
119	48	4	364	39.97
120	96	2	254	27.89
150	96	4	613	67.31

UNMETERED SERVICE RATES

(4) **FLUORESCENT CROSSWALK (cont.)**

b) Photocell Operation - Operating Only

310	24	2	30	$4.24
311	48	4	166	23.47
312	72	2	116	16.40
313	72	4	222	31.39
314	96	1	47	6.65
315	72	1	60	8.48
350	96	4	280	39.59

(5) **LOW PRESSURE SODIUM**

Rate Code	**Watts**	**kWh/Mo.**	**$/Mo.**	**Other**
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	$26.03	
131	180	80	31.25	
132	90	45	23.91	
b) Operating and Maintenance Only				
231	180	80	23.42	
c) Operating Only				
331	180	80	11.31	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

121	250	100	$21.25	
122	400	150	28.43	
123	70	32	11.46	
124	100	45	13.32	
125	150	65	16.31	
126	100	99	21.87	Continuous Operation

UNMETERED SERVICE RATES

(6) **HIGH PRESSURE SODIUM (**cont'd)

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
221	250	100	$18.18	
222	70	32	8.57	
223	100	45	10.40	
224	150	65	13.23	
c) Operating Only				
321	250	100	$14.14	
322	70	32	4.53	
323	100	45	6.36	
324	150	65	9.19	
326	400	150	21.21	
327	500	183	25.88	
328	1000	363	51.33	
329	1500	500	70.70	

(7) **METALLIC ADDITIVE**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
140	400	150	$31.29	
141	1000	360	65.83	
142	250	100	27.39	
143	150	67	22.72	
144	100	50	20.32	
b) Operating Only				
341	1000	360	$50.91	
342	400	150	21.21	
343	250	100	14.14	
344	175	75	10.61	
345	150	67	9.47	
346	100	50	7.07	

UNMETERED SERVICE RATES

(8) LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY

Rate Code	$/Mo.	Other
530	$0.34	Non – Continuous
531	$0.58	Continuous

(9) LIGHT EMITTING DIODE (LED) – Operating Only

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
532	44	15	$2.12	
533	66	22	3.11	
534	88	29	4.10	
535	92	31	4.38	
536	105	35	4.95	
537	170	57	8.06	
539	110	37	5.23	
540	65	22	3.11	
541	55	18	2.55	
542	83	28	3.96	
543	48	16	2.26	
544	72	24	3.39	

(10) INTERIM LIGHT EMITTING DIODE (LED) – Operating & Capital Only[1]

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
615	44	15	$10.18	
616	55	18	10.61	
617	74	25	11.60	
618	87	29	12.16	
619	65	22	11.17	
620	88	29	12.16	
621	110	37	13.29	
622	173	58	16.26	

[1] While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

UNMETERED SERVICE RATES

(B) MISCELLANEOUS LIGHTING

DEMAND CHARGE

$10.963 per month per kilowatt of connected load.

ENERGY CHARGE

12.537 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

8.324 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $16.31 per month if such unmetered service is billed separately from any metered account.

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

UNMETERED SERVICE RATES

(C) MISCELLANEOUS SMALL LOADS

DEMAND CHARGE

$10.963 per month per kilowatt of connected load.

ENERGY CHARGE

12.537 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

8.324 cents per kilowatt hour for all additional kilowatt hours.

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be $16.31 per month if such unmetered service is billed separately from any metered account.

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

Proposed Rates

2014 Tariffs - Rate Stabilization

DOMESTIC SERVICE TARIFF
Rate Codes 02, 03, 04

CUSTOMER CHARGE

$10.83 per month

ENERGY CHARGE

14.241 cents per kilowatt hour

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06

CUSTOMER CHARGE

$18.82 per month

ENERGY CHARGE

<u>December, January and February</u>

07:00 am to 12:00 pm	18.596 cents per kilowatt hour
12:00 pm to 04:00 pm	14.241 cents per kilowatt hour
04:00 pm to 11:00 pm	18.596 cents per kilowatt hour
11:00 pm to 07:00 am	7.318 cents per kilowatt hour

The above rates apply weekdays (Monday to Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 7.318 cents per kilowatt hour.

<u>March to November</u>

07:00 am to 11:00 pm	14.241 cents per kilowatt hour
11:00 pm to 07:00 am	7.318 cents per kilowatt hour

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 7.318 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06

Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

SMALL GENERAL TARIFF
Rate Code 10

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

15.121 cents per kilowatt hour for the first 200 kilowatt hours per month

13.303 cents per kilowatt hour for all additional kilowatt hours

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable.

GENERAL TARIFF
Rate Code 11

DEMAND CHARGE

$10.500 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

11.211 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand.

7.931 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

DEMAND CHARGE

$13.334 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

8.022 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

(3) The Company reserves the right to have a separate service and/or operating agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

DEMAND CHARGE

$7.709 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

10.083 cents per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand.

7.701 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering.

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

MEDIUM INDUSTRIAL TARIFF
(250 kVA or 225 kW – 1,999 kVA or 1,799 kW)
Rate Code 22

DEMAND CHARGE

$12.487 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

7.233 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$11.903 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

7.241 cents per kilowatt hour

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating a telephone call to send notice to the customer’s dedicated telephone number requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer’s dedicated telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer’s performance during the interruption event is calculated as per the formula below:

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall

be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

MUNICIPAL TARIFF

DEMAND CHARGE

$12.449 per month per kilovolt ampere of the higher of:

a) maximum actual demand of the current month or

b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

7.541 cents per kilowatt hour.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

LOAD RETENTION TARIFF

DEMAND CHARGE

To be determined as specified in Special Condition (1).

ENERGY CHARGE

To be determined as specified in Special Condition (1).

AVAILABILITY

(1) This rate shall be granted only in circumstances where it can be shown that:

- The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible, or the rate is required to respond to the competitive challenge of business closure due to economic distress; and
- Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question; and
- The revenue from service to a customer under this rate shall be greater than the applicable incremental cost to serve such customer and shall make a significant positive contribution to fixed costs.

The procedure for establishing that this test is satisfied is outlined in Attachment A.

(2) This rate shall be available only to customers who have a minimum load of and/or who are considering an alternate supply of at least 2000 KVA or 1800 KW. Where the rate is required to respond to the competitive challenge of business closure due to economic distress this rate shall be available only to Extra-Large Industrial customers.

(3) The customer shall apply in writing to take service under this rate.

(4) This rate shall be available only to customers whose electricity needs, at the date of application, are being supplied by NSPI and have been supplied by NSPI for at least two consecutive years at the time of the request. It is not available for new load.

MINIMUM LOAD REQUIREMENT

All customers must agree to maintain a minimum level of load while taking service under the rate, subject to (i) any terms or conditions relating to supply interruption that may be outlined in the pricing conditions of the rate, (ii) the customer's requirement to take downtime for maintenance purposes and (iii) market downtime, labour disruption and other matters beyond the reasonable control of the customer.

SECURITY FOR PAYMENT OF ACCOUNT

A customer taking service under this rate must provide security for payment of the customer's account, regardless of payment history. Appropriate security shall be satisfactory to Nova Scotia Power Inc. Acceptable security will be described in the pricing of the rate, and may be revised or updated from time to time upon approval of the UARB.

DISCONNECTION OF ELECTRIC SERVICE

In the event of non-payment, NSPI may disconnect a customer on two business days' notice. In the event of a dispute under the tariff, the complaint will be made directly to the Board for resolution, as opposed to the Dispute Resolution Officer.

SPECIAL CONDITIONS

(1) The price, terms and conditions (including any modification in special conditions associated with the rate(s) under which the customer purchased power and energy prior to taking service under this rate) shall be established jointly by NSPI and the customer, following the procedure outlined in Attachment A.

(2) The price, terms and conditions offered under this rate shall be determined on a customer by customer basis.

(3) The price, terms and conditions offered under this rate shall be submitted by NSPI to the UARB for approval.

LOAD RETENTION TARIFF

ATTACHMENT A

This attachment outlines procedures by which the requirements of Availability Clause (1) and Special Condition (1) are to be satisfied.

(1) The customer shall apply in writing to take service under this rate, outlining the available alternate supply option or the potential for closure due to economic distress and the rationale for seeking service under the load retention rate.

(2) Upon written application by a customer to take service under this rate which meets the requirements of clause (1) above, the UARB shall direct that NSPI conduct a screening to determine whether the implementation of these procedures is warranted.

(3) Subject to (2), NSPI and the customer shall proceed to implement these procedures and establish a load retention price, with appropriate terms and conditions.

(4) Should there be disagreement between NSPI and the customer with respect to the decision to proceed, the customer may ask the UARB to adjudicate.

(5) These procedures shall be applied on a customer by customer basis.

(6) To protect confidential NSPI and customer data, none of the data or analysis used in the implementation of these procedures, nor any results thereof, including the recommended price, terms and conditions, shall be required to be publicly disclosed.

(7) The economic feasibility of the customer's option to supply some or all of its own load shall be established where it can be shown that under reasonable assumptions the cost of electricity to the customer from that option is expected to be lower than the cost to the customer of continuing to purchase electricity from NSPI.

(8) The cost to the customer of the alternate supply shall reflect all appropriate factors, including but not limited to:

- Capital costs
- Fixed and Variable Operating costs
- Fuel costs (short and long term, contracts, etc.)
- Ancillary Services costs (electric)
- Steam production and steam backup costs (where appropriate)
- Contributions-in-aid of construction (where NSPI's system must be modified to accommodate the customer's generator)
- Expected Service Life
- Salvage Value
- Electric sales/purchases (where the customer's generator output does not match customer requirements)
- Depreciation and/or Capital Cost Allowance
- Taxes
- Appropriate return

LOAD RETENTION TARIFF

(9) The technical feasibility of the customer's alternate supply shall reflect all appropriate factors, including but not limited to:

- Technology maturity and proven performance level
- Site specific considerations (space requirements, availability of cooling water, fuel handling, etc.)
- Environmental acceptability (air emissions, solid waste management, etc.)
- Modifications to NSPI's transmission and/or distribution system to accommodate the new generation and/or to supply ancillary services.
- Metering systems
- Where cogen is involved, compatibility of steam versus electric requirements.

(10) If the customer is applying for a load retention rate on the basis of economic distress, the customer shall provide NSPI and the UARB proof of economic distress, the adequacy of which shall be determined by the UARB prior to approving any proposed rate, including:

- Current and historical financial information for a minimum of at least three (3) fiscal years of the customer
- Evidence of activities undertaken by the customer in the last three (3) years to reduce costs
- Affidavit of a senior executive of the customer or its parent indicating the need for the requested load retention rate. Whether the affidavit is provided by an executive of the customer or the parent must be consistent with whether it will be the customer or parent who will make the decision to leave NSPI's system in the absence of the load retention rate. Further the affidavit should include
    - An analysis of the market in which the customer operates
    - Identification of the factors other than electricity costs that are contributing to the economic hardship
    - The customer's plan to address the above factors
    - An estimate of the electricity price that could alleviate the economic hardship
    - An estimate of the probability that the customer will leave NSPI's system if the requested load retention rate is not granted

- Such other information as reasonably requested by NSPI or the UARB.

(11) The impact on NSPI's other customers of losing the customer load in question, shall be determined using NSPI's forecasting and planning models (as appropriate) to compare scenarios that include either the customer's move to an alternate supply or cessation of operations, as the case may be, with scenarios that assume the customer continues to be supplied by NSPI.

(12) Where the impact on NSPI's other customers can be mitigated by offering the customer

in question a load retention rate, NSPI and the customer shall determine an appropriate rate for the customer. This shall include the price (which may be formula-driven), and any other terms and conditions, including (where relevant) a suggested term and any appropriate renewal guidelines.

LOAD RETENTION TARIFF PRICING MECHANISM

AVAILABILITY:

1. This Load Retention Pricing Mechanism (Pricing Mechanism) is available to, Bowater Mersey Paper Company Ltd (Bowater) for energy other than presently served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this Pricing Mechanism must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF tariff customers, and in advance of Interruptible Rider customers.

4. This Pricing Mechanism cannot be taken in conjunction with other Tariffs, except for the ability of Bowater to take energy under the Mersey Agreement.

RATE MECHANISM:

The intent of this rate is to create a mechanism whereby customers on the rate pay the variable incremental costs of service, plus a significant positive contribution to fixed costs, such that other customers are better off by retaining the customers rather than having the customers depart the system and make no contribution to fixed cost recovery.

LOAD RETENTION TARIFF PRICING MECHANISM

CHARGES:

Energy Charge

The Energy Charge shall be as follows:

Year (January 1 to December 31)	Variable Incremental Rate (cents per kWh)	Contribution to fixed costs (cents per kWh)	Energy charge (cents per kWh)
2012	5.624	0.4	6.024
2013	6.177	0.4	6.577
2014	6.386	0.4	6.786

RE-OPENER CLAUSE

The UARB reserves the right to adjust the above rates on a prospective basis if actual costs significantly vary from Load Retention Rate assumptions. Following any adjustment, the customer would be provided the opportunity to determine whether to remain on the rate.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) is applicable to the Tariff for the 2012 rate year only. For 2012, the rate applicable to the Extra Large Industrial Two Part Real Time Pricing Tariff (ELI 2P-RTP) approved by the UARB pursuant to the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge in 2012.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the ELI 2P-RTP Tariff for the 2012 rate year on account of fuel and purchased power costs incurred in 2010 and 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2012 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2012.

The ELI 2P-RTP portion of the FAM BA (in cents per kilowatt hour) for the 2013 rate year on account of fuel and purchased power costs incurred in 2011, as approved by the UARB pursuant to the FAM Tariff, including the applicable 2013 portion of the 2010 costs of fuel and purchased power deferred for recovery by the UARB in its December 17, 2010 Order (P-887(2)) shall apply, in addition to the energy charge in 2013.

No other FAM charges shall be applicable to this Tariff.

LOAD RETENTION TARIFF PRICING MECHANISM

SPECIAL CONDITIONS:

Major Scheduled Maintenance Periods

The customer will annually provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

Day Ahead Forecast

The customer shall supply NSPI, by 0800 hours each day, a 24 hour forecast for the following day of the customer's hourly requirements in MW.

Minimum Load Requirement:

The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a regular demand of 25 000 kVA.

Supply Interruption:

This Pricing Mechanism is interruptible for supply reasons. The customer will reduce its subscribed interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating a telephone call to send notice to the customer requiring such reduction. Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes. The customer must maintain a telephone number and telephone system in working order at all times and must have a designated staff person to answer the telephone at all times. The failure of the customer to receive a notice that has been initiated and sent by NSPI to the customer's telephone number, including failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider

Supply Interruption calls will be made to all customers taking energy pursuant to this Pricing Mechanism on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the cost of the applicable billing for energy taken under this tariff effective at that time for the consumption used in that billing month.

LOAD RETENTION TARIFF PRICING MECHANISM

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + (($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A"

The total penalty will not exceed two times the cost of the appropriate billing effective at that time for the consumption used in that billing month.

Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable firm service rate, a five (5) year advance written notice must be given to the company so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to Interruptible service in the future, the customer may convert to interruptible service following two (2) years service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GR&LF) Rate;
2. Load Retention Tariff Pricing Mechanism;
3. Interruptible Rider to the Large Industrial Rate.

LOAD RETENTION TARIFF PRICING MECHANISM

Maintain System Integrity

The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic Voltage and current levels, Voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

Security for Payment of Account

The customer shall make weekly payments on account of its estimated monthly billings from NSPI. NSPI shall provide the customer with a reasonable estimated weekly billing for each week (Monday through Sunday, prorated for the first and last week, or such other weekly period as the customer and NSPI may agree) during the term. Prior to close of business each Thursday immediately following a billing week (or as otherwise subsequently agreed), the customer shall make a payment by wire transfer to NSPI's account equal to that prior week's estimated amount as provided by NSPI. If NSPI does not provide the applicable weekly estimate to the customer in advance of the Thursday payment requirement, the customer shall make payment in accordance with the immediately prior estimate. At the end of each month the customer shall, as applicable, make an additional payment or receive a credit towards its next payment in order to balance its account to actual prior month's usage.

Separate Service Agreement

The Company reserves the right to have a separate service agreement if, in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

LOAD RETENTION TARIFF PRICING MECHANISM

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

Metering Costs

Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

OUTDOOR RECREATIONAL LIGHTING TARIFF
Rate Code 41

ENERGY CHARGE

15.410 cents per kilowatt hour for all metered kilowatt hours per month.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatthour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

UNMETERED SERVICE RATES

(A) **STREET AND AREA LIGHTING**

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in Cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

RATES

(1) **INCANDESCENT**

Rate Code	**Watts**	**kWh/Mo.**	**$/Mo.**	**Other**
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$21.67	
002	Greater than 300	154	30.43	
b) Operating Only				
003	300 and Less	97	14.70	

UNMETERED SERVICE RATES

(2) **MERCURY VAPOUR**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$14.81	
101	125	52	17.65	
102	175	69	18.50	
103	250	97	23.47	
104	400	154	32.19	
105	700	260	49.44	
106	1000	363	66.09	
107	250	212	38.82	Continuous Operation
b) Operating and Maintenance Only				
201	125	52	$14.66	
202	175	69	15.53	
203	250	97	19.79	
204	400	154	28.43	
205	700	260	44.50	
206	1000	363	60.12	
c) Operating Only				
301	125	52	$7.87	
302	175	69	10.44	
303	250	97	14.70	
304	400	154	23.34	
305	700	260	39.41	
306	1000	363	55.03	

UNMETERED SERVICE RATES

(3) FLUORESCENT

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)					
110	24	2	30	$17.16	
111	48	2	85	25.75	
112	72	2	116	30.92	
113	72	4	222	48.09	
114	96	1	47	20.24	
115	72	1	60	21.85	
116	48	4	166	38.60	
b) Operating and Maintenance Only					
213	72	4	222	$43.81	
214	96	1	47	17.29	
215	72	1	60	19.28	
216	48	4	166	35.36	
217	48	1	49	17.59	
218	48	2	85	23.07	
c) Operating Only					
330	35	4	47	7.11	

(4) FLUORESCENT CROSSWALK

a) Continuous Burning - Operating Only

117	72	4	486	$57.20
118	24	2	66	7.76
119	48	4	364	42.86
120	96	2	254	29.91
150	96	4	613	72.16

UNMETERED SERVICE RATES

(4) **FLUORESCENT CROSSWALK (cont.)**

b) Photocell Operation - Operating Only

310	24	2	30	$4.56
311	48	4	166	25.18
312	72	2	116	17.60
313	72	4	222	33.63
314	96	1	47	7.11
315	72	1	60	9.10
350	96	4	280	42.46

(5) **LOW PRESSURE SODIUM**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	$30.14	
131	180	80	35.76	
132	90	45	27.85	
b) Operating and Maintenance Only				
231	180	80	27.40	
c) Operating Only				
331	180	80	12.13	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

121	250	100	$23.46	
122	400	150	31.15	
123	70	32	12.95	
124	100	45	14.94	
125	150	65	18.16	
126	100	99	24.85	Continuous Operation

UNMETERED SERVICE RATES

(6) **HIGH PRESSURE SODIUM (**cont'd)

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
221	250	100	$20.25	
222	70	32	9.93	
223	100	45	11.90	
224	150	65	14.94	
c) Operating Only				
321	250	100	$15.16	
322	70	32	4.84	
323	100	45	6.81	
324	150	65	9.85	
326	400	150	22.74	
327	500	183	27.75	
328	1000	363	55.04	
329	1500	500	75.80	

(7) **METALLIC ADDITIVE**

a) Operating, Maintenance and Capital (Full Charge)			
140	400	150	$34.68
141	1000	360	72.33
142	250	100	31.11
143	150	67	26.10
144	100	50	23.53
b) Operating Only			
341	1000	360	$54.57
342	400	150	22.74
343	250	100	15.16
344	175	75	11.37
345	150	67	10.15
346	100	50	7.58

UNMETERED SERVICE RATES

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

Rate Code	$/Mo.	Other
530	$0.36	Non – Continuous
531	$0.63	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
532	44	15	$2.27	
533	66	22	3.34	
534	88	29	4.40	
535	92	31	4.70	
536	105	35	5.31	
537	170	57	8.64	
539	110	37	5.61	
540	65	22	3.34	
541	55	18	2.73	
542	83	28	4.24	
543	48	16	2.43	
544	72	24	3.64	

(10) **INTERIM LIGHT EMITTING DIODE (LED) – Operating & Capital Only**[1]

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
615	44	15	$10.57	
616	55	18	11.03	
617	74	25	12.09	
618	87	29	12.70	
619	65	22	11.64	
620	88	29	12.70	
621	110	37	13.91	
622	173	58	17.09	

[1] While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

UNMETERED SERVICE RATES

(B) MISCELLANEOUS LIGHTING

DEMAND CHARGE

$11.753 per month per kilowatt of connected load.

ENERGY CHARGE

13.440 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

8.924 cents per kilowatt hour for all additional kilowatt hours.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $17.49 per month if such unmetered service is billed separately from any metered account.

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

UNMETERED SERVICE RATES

(C) MISCELLANEOUS SMALL LOADS

DEMAND CHARGE

$11.753 per month per kilowatt of connected load.

ENERGY CHARGE

13.440 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

8.924 cents per kilowatt hour for all additional kilowatt hours.

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be $17.49 per month if such unmetered service is billed separately from any metered account.

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

	2013	2014
Rate Case - Above-the-Line General Percentage Increase	6.565%	5.3796%
Overhead Percentages		
Fringe - Union	[redacted]	[redacted]
Administrative Overhead	77.19%	77.19%
Vehicle Overhead	50.67%	50.67%
Labor Rates		
CSFR regular rate	$ 26.97	$ 27.73
PLT Senior	$ 37.11	$ 38.15
PLT Junior	$ 35.34	$ 36.33
Wiring Inspector	$ 36.30	$ 37.32
Meter Data Engineer	[redacted]	[redacted]
Meter Data Technologist	[redacted]	[redacted]
Three Phase Meter Person	$ 36.45	$ 37.47
Labor Costs		
3 Phase - Hours to Perform	16.00	16.00
Single Phase - Hours to Perform	8.00	8.00
Other Costs		
3 Phase Material Costs	$ 3,180.00	$ 3,180.00
Single Phase Materials Costs	$ 1,377.00	$ 1,377.00
AMR Meter Cost - average cost	$ 520.00	$ 520.00
Non AMR Meter - average cost	$ 220.00	$ 220.00
Times and Volumes		
Average Connection Time (hrs)	0.625	0.625
Minimum Call out Time (hrs)	4.000	4.000

Regulation 7.1 Schedule of Charges for 2013

Regulation Section	Description	Current Rate (2012)	Proposed Rate (rounded)	Assumptions Supporting Proposed Rates
7.1 (a)	Connection/reconnection during normal working hours	$ 25.00	$ 27.00	Average connection time (hrs) 0.625 includes activity, travel, training, etc. CSFR regular rate ($/hr) $ 26.97 CSFR = Customer Service Field Rep 2012 rate plus increase by 2.8% Labour cost $ 16.86 Fringe $ 3.03 18.0% Administrative Overhead $ 15.36 77% applied to labour rate including fringe Vehicle overhead $ 10.08 51% applied to labour rate including fringe Recommended charge $ 45.33
7.1 (b&c)	Connection/reconnection after normal working hours	Standard Charge $ 25.00 plus $ 67.00	Standard Charge $ 27.00 plus $ 71.00	Call-out labour cost $ 144.91 PLT labour - Collective agreement dictates minimum 4 hour call-out Proportionate amount (A) $ 36.23 25% of after hours work are call-outs (mgmt estimate) Work continuation labour cost $ 33.72 CSFR labour - Overtime based on double time Proportionate amount (B) $ 25.29 75% of after hours work are work continuation (mgmt estimate) Total Labour cost (A+B) $ 61.52 Fringe $ 11.07 18.0% Administrative Overhead $ 28.02 38.6% O/H rates are reduced by 50% for O/T labour costs Vehicle overhead $ 18.39 25.3% O/H rates are reduced by 50% for O/T labour costs Total cost $ 118.99 less: Standard charge -$ 27.00 Recommended incremental charge $ 91.99
7.1 (d)	Connection/reconnection to any premises serviced by temporary service	$ 25.00 Standard charge p all costs incurred by the Company	$ 27.00 Standard charge plus all costs incurred by the Company	See 7.1 (a)
7.1 (e)	Disconnection-Seasonal Electric Service	$ 26.00	$ 28.00	Proposed rate is based on 2012 rate plus the general rate increase applicable to above the line customers
7.1 (f)	Returned Cheque Charge	$ 21.00	$ 22.00	Proposed rate is based on 2012 rate plus the general rate increase applicable to above the line customers
7.1 (i)	Dispute Test Fee re satisfactory meter	$ 34.00	$ 36.00	Proposed rate is based on 2012 rate plus the general rate increase applicable to above the line customers
7.1 (j)	Standard Contribution for three-phase15 kW and under	$ 1,098.00	$ 1,170.00	The contribution is a charge to a customer for a 3 phase install with a 15 kW or less demand only. If it is a 3 phase & over 15 kW, there is no contribution, as the regular usage charge will offset the initial costs. **Costing methodology:** The contribution charge will be NSPI's cost differential between a 3 phase install and a single phase install. **Cost analysis:** (see below)

Cost analysis (7.1 (j)):

		3 Phase	Single Phase	Incremental Cost
Labour		$ 583	$ 292	$ 292
Fringe	18%	105	52	52
Administrative O/H	77%	531	266	266
Vehicle O/H	51%	349	174	174
Materials		3,180	1377	1,803
Total		$ 4,748	$ 2,161	$ 2,587
			Contribution charge	$ 2,587

Regulation 7.2 Schedule of Wiring Inspection Fees - Proposed Rates for 2013

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.2.7 d)	Plans examination	$ 102.00 0-1000 amps	$ 109.00 0-1000 amps	Based on proposed hourly rate inspections 7.2 (g) - 2 hours = $ 118.00
7.2	Inspection Fee Schedule			

Installed Value of Electrical Installation	Current Rate	Proposed Rate (rounded)	Installed Value of Electrical Installation	Inspection Visits	Time per Inspection*	Labour Cost	Overheads	Proposed Charge
$0,000 to $2,000	$ 61.00	$ 65.00	$0,000 to $2,000	1	0.88	$ 37.79	$ 48.32	$ 86.12
$2,001 to $4,000	$ 123.00	$ 131.00	$2,001 to $4,000	2	0.88	$ 75.59	$ 96.65	$ 172.23
$4,001 to $6,000	$ 207.00	$ 221.00	$4,001 to $6,000	2	1.47	$ 125.98	$ 161.08	$ 287.05
$6,001 to $8,000	$ 252.00	$ 269.00	$6,001 to $8,000	2	1.76	$ 151.17	$ 193.29	$ 344.46
$8,001 to $10,000	$ 294.00	$ 313.00	$8,001 to $10,000	2	2.06	$ 176.37	$ 225.51	$ 401.87
$10,001 to $15,000	$ 411.00	$ 438.00	$10,001 to $15,000	3	2.35	$ 302.35	$ 386.58	$ 688.93
$15,001 to $25,000	$ 522.00	$ 556.00	$15,001 to $25,000	3	3.24	$ 415.73	$ 531.55	$ 947.27
$25,001 to $50,000	$ 755.00	$ 805.00	$25,001 to $50,000	3	4.12	$ 529.11	$ 676.52	$ 1,205.62
$50,001 to $100,000	$ 1,073.00	$ 1,143.00	$50,001 to $100,000	3	5.00	$ 642.49	$ 821.48	$ 1,463.97
$100,001 to $300,000	$ 1,683.00	$ 1,793.00	$100,001 to $300,000	4	5.88	$ 1,007.82	$ 1,288.60	$ 2,296.42
$300,001 to $500,000	$ 2,103.00	$ 2,241.00	$300,001 to $500,000	5	5.88	$ 1,259.78	$ 1,610.75	$ 2,870.53
$500,001 to $750,000	$ 2,524.00	$ 2,690.00	$500,001 to $750,000	6	5.88	$ 1,511.73	$ 1,932.90	$ 3,444.64
$750,001 to $1,000,000	$ 3,365.00	$ 3,586.00	$750,001 to $1,000,000	8	5.88	$ 2,015.64	$ 2,577.20	$ 4,592.85
$1,000,000	$ 4,113.00 plus 0.15% of cost in excess of $1,000,000	$ 4,383.00 plus 0.15% of cost in excess of $1,000,000	$1,000,000	10	5.88	$ 2,519.56	$ 3,221.50	$ 5,741.06

Wiring Inspector Hourly Rate rate including fringe	$ 42.83	
Overhead rates:	Administrative O/H	77%
	Vehicle O/H	51%
	Fringe	18.0%

* includes travel time, training etc.

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.2	New installations: minimum inspection fees			Based on Fee schedule and assumptions noted above
	Residential - all installations	$123.00	$131.00	Based on Fee schedule for installed value of $2,001 - $4,000
	Commercial/Industrial institutional:			
	Up to 100 AMPS	$123.00	$131.00	Based on Fee schedule for installed value of $2,001 - $4,000
	Over 100 to 400 AMPS	$294.00	$313.00	Based on Fee schedule for installed value of $8,001 - $10,000
	Over 400 to 800 AMPS	$411.00	$438.00	Based on Fee schedule for installed value of $10,001 - $15,000
	Over 800 to 1000 AMPS	$522.00	$556.00	Based on Fee schedule for installed value of $15,001 - $25,000
	Over 1000 AMPS	$755.00	$805.00	Based on Fee schedule for installed value of $25,001 - $50,000
7.2 g)	Hourly Rate inspections			Key Assumptions for this section:

Wiring inspector rate plus fringe		$42.83	
Regular Labour A/O		$33.06	77.2%
Overtime A/O			38.6%
Vehicle A/O		$21.70	50.7%
Overtime vehicle A/O			25.3%
Total rate (regular hours) including A/O		$97.60	
Labour Efficiency (travel, training, etc.)		85%	
Effective hourly rate		$114.82	

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
	Normal Working Hours:			**Normal Working Hours**
i)	*For the first hour or fraction thereof*	$ 60.00	$ 64.00	*For the first hour or fraction thereof:*
ii)	*For each additional half-hour or fraction thereof*	$ 25.00	$ 27.00	Hourly rate charge $114.82
				For each additional half-hour or fraction thereof:
				Charge rate (50% of hourly rate above) $57.41
	Outside Normal Working Hours Extension of a regular working day (before or after)			**Outside Normal Working Hours**
i)	*For the first hour or fraction thereof:*	$ 81.00	$ 86.00	Extension of a regular working day (before or after) — Labour efficiency not applied
ii)	*For each additional half-hour or fraction thereof:*	$ 35.00	$ 37.00	*For the first hour or fraction thereof:* — as covered under normal work day

Labour (double time)	$85.66	
A/O	$33.06	38.6%
Vehicle A/O	$21.70	25.3%
Hourly rate charge	$140.43	
For each additional half-hour or fraction thereof:		
Labour (1/2 hour)	$42.83	
Overheads	27.38	
Charge rate	$70.22	

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
	Weekends and Statutory Holidays Scheduled inspections on weekends (Saturday, Sunday and statutory holidays:			Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays: — Labour efficiency not applied as covered under normal work day
i)	*Minimum Fee:*	$ 134.00	$ 143.00	*Minimum Fee:* — Minimum call-out is 4 hours based on provisions of the Collective Agrrement
ii)	*For each additional half-hour above 4 hours*	$ 48.00	$ 51.00	

Labour	$171.33	
A/O	$132.25	77.2%
Vehicle A/O	$86.81	50.7%
Hourly rate charge	$390.39	
For each additional half-hour above 4 hours		
Labour (1/2 hour)	$42.83	
Overheads	27.38	
Charge rate	$70.22	

Regulation 7.3 Schedule of Load Research, Monitoring, Reporting and Analytical Charges - Proposed Rates for 2013

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.3 Section 1.0	Schedule of load research charges One rate for all equipment types Bi-monthly Monthly	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter	Subsection 1.0 **Recovery of Capital Cost of Meter Equipment**
7.3 Section 2.0	Recovery of Installation Charges Single Phase Service, Self-Contained Single Phase Service, Transformer Rated Three Phase Service	 $ 39.00 $ 106.00	 $ 42.00 $ 113.00	Subsection 2.0 **Recovery of Installation charges** **Single Phase-Self Contained** Labour [redacted] CSFR for 0.5 hours Fringe 18.0% Administrative Overhead 77% Vehicle Overhead 51% Sub-total [redacted] Mark up (internal costs) $ 9.07 25% based on 7.3 b) and c) Charge for service [redacted] **Three Phase** installation charge: Labour [redacted] Three phase meter person for 1 hour Fringe 18.0% Administrative Overhead 77% Vehicle Overhead 51% Sub-total [redacted] Mark up [redacted] 25% based on 7.3 b) and c) Charge for service [redacted] Note: Determined no longer necessary to distinguish between single phase self-contained and single phase transformer rated When organized and paid for by NSPI, recovery of telephone line installation charges will be at cost.
3.0	Recovery of Operational Charges Toll Free Phone Line Operation	 $ 186.00	 $ 188.00	Subsection (new) 3.0 **Recovery of Operational Charges** Average Weighted Call Time 2 minutes Long Distance Charges $0.02 per minute Cost of Capital (WACC) 7.76% Call attempts Per Year 365 Long Distance Charges $188.14
4.0	Load Research Setup	$ 42.00	$ 45.00	Subsection 3.0 **Load research set-up** Labour [redacted] Meter Data Technologist (.75 hrs),Meter Engineer (.25 hrs) Fringe 18.0% Non-union Administrative Overhead 77% Sub-total Mark up [redacted] 25% based on 7.3 b) and c) Charge for service
6.0	Specialized Analysis Hourly rate	 $ 73.00	 $ 78.00	Subsection 5.0 **Specialized Analysis** Labour [redacted] Meter Data Technologist (1 hr) - estimated labour rate Fringe 18.0% Non-union Administrative Overhead 77% Sub-total Mark up [redacted] 25% based on 7.3 b) and c) Charge for service per hour

Regulation 7.2 Schedule of Wiring Inspection Fees - Proposed Rates for 2014

Regulation Section	Description	Current Rate (2013)	Proposed Rate (rounded)	Assumptions Supporting Proposed Rates
7.1 (a)	Connection/reconnection during normal working hours	$ 27.00	$ 28.00	Average connection time (hrs) 0.625 includes activity, travel, training, etc. CSFR regular rate ($/hr) $ 27.73 CSFR = Customer Service Field Rep estimated 2013 rate plus increase by 2.8% Labour cost $ 17.33 Fringe $ 3.12 18.0% Administrative Overhead $ 15.78 77% applied to labour rate including fringe Vehicle overhead $ 10.36 51% applied to labour rate including fringe Recommended charge $ 46.59
7.1 (b&c)	Connection/reconnection after normal working hours	Standard Charge $ 27.00 plus $ 71.00	Standard Charge $ 28.00 plus $ 75.00	Call-out labour cost $ 148.96 PLT labour - Collective agreement dictates minimum 4 hour call-out Proportionate amount (A) $ 37.24 25% of after hours work are call-outs (mgmt estimate) Work continuation labour cost $ 34.66 CSFR labour - Overtime based on double time Proportionate amount (B) $ 25.99 75% of after hours work are work continuation (mgmt estimate) Total Labour cost (A+B) $ 63.23 Fringe $ 11.38 18.0% Administrative Overhead $ 28.80 38.6% O/H rates are reduced by 50% for O/T labour costs Vehicle overhead $ 18.90 25.3% O/H rates are reduced by 50% for O/T labour costs Total cost $ 122.31 less: Standard charge -$ 28.00 Recommended incremental charge $ 94.31
7.1 (d)	Connection/reconnection to any premises serviced by temporary service	$ 27.00 Standard charge p all costs incurred by the Company	$ 28.00 Standard charge plus all costs incurred by the Company	See 7.1 (a)
7.1 (e)	Disconnection-Seasonal Electric Service	$ 28.00	$ 30.00	Proposed rate is based on estimated 2013 rate plus the general rate increase applicable to above the line customers
7.1 (f)	Returned Cheque Charge	$ 22.00	$ 23.00	Proposed rate is based on estimated 2013 rate plus the general rate increase applicable to above the line customers
7.1 (i)	Dispute Test Fee re satisfactory meter	$ 36.00	$ 38.00	Proposed rate is based on estimated 2013 rate plus the general rate increase applicable to above the line customers
7.1 (j)	Standard Contribution for three-phase15 kW and under	$ 1,170.00	$ 1,233.00	The contribution is a charge to a customer for a 3 phase install with a 15 kW or less demand only. If it is a 3 phase & over 15 kW, there is no contribution, as the regular usage charge will offset the initial costs. **Costing methodology:** The contribution charge will be NSPI's cost differential between a 3 phase install and a single phase install. **Cost analysis:**

		3 Phase	Single Phase	Incremental Cost
Labour		$ 600	$ 300	$ 300
Fringe	18%	108	54	54
Administrative O/H	77%	546	273	273
Vehicle O/H	51%	358	179	179
Materials		3,180	1377	1,803
Total		$ 4,792	$ 2,183	$ 2,609
			Contribution charge	$ 2,609

Regulation 7.2 Schedule of Wiring Inspection Fees - Proposed Rates for 2014

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.2.7 d)	Plans examination	$ 109.00 0-1000 amps	$ 115.00 0-1000 amps	Based on proposed hourly rate inspections 7.2 (g) - 2 hours = $ 123.00

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Installed Value of Electrical Installation	Inspection Visits	Time per Inspection*	Labour Cost	Overheads	Proposed Charge
7.2	Inspection Fee Schedule								
	Installed Value of Electrical Installation								
	$0,000 to $2,000	$ 65.00	$ 68.00	$0,000 to $2,000	1	0.88	$ 38.85	$ 49.68	$ 88.53
	$2,001 to $4,000	$ 131.00	$ 138.00	$2,001 to $4,000	2	0.88	$ 77.71	$ 99.35	$ 177.06
	$4,001 to $6,000	$ 221.00	$ 233.00	$4,001 to $6,000	2	1.47	$ 129.51	$ 165.59	$ 295.10
	$6,001 to $8,000	$ 269.00	$ 283.00	$6,001 to $8,000	2	1.76	$ 155.41	$ 198.71	$ 354.12
	$8,001 to $10,000	$ 313.00	$ 330.00	$8,001 to $10,000	2	2.06	$ 181.31	$ 231.83	$ 413.14
	$10,001 to $15,000	$ 438.00	$ 462.00	$10,001 to $15,000	3	2.35	$ 310.82	$ 397.42	$ 708.24
	$15,001 to $25,000	$ 556.00	$ 586.00	$15,001 to $25,000	3	3.24	$ 427.38	$ 546.45	$ 973.83
	$25,001 to $50,000	$ 805.00	$ 848.00	$25,001 to $50,000	3	4.12	$ 543.94	$ 695.48	$ 1,239.42
	$50,001 to $100,000	$ 1,143.00	$ 1,204.00	$50,001 to $100,000	3	5.00	$ 660.50	$ 844.52	$ 1,505.02
	$100,001 to $300,000	$ 1,793.00	$ 1,889.00	$100,001 to $300,000	4	5.88	$ 1,036.08	$ 1,324.73	$ 2,360.81
	$300,001 to $500,000	$ 2,241.00	$ 2,362.00	$300,001 to $500,000	5	5.88	$ 1,295.10	$ 1,655.91	$ 2,951.01
	$500,001 to $750,000	$ 2,690.00	$ 2,835.00	$500,001 to $750,000	6	5.88	$ 1,554.12	$ 1,987.10	$ 3,541.21
	$750,001 to $1,000,000	$ 3,586.00	$ 3,779.00	$750,001 to $1,000,000	8	5.88	$ 2,072.16	$ 2,649.46	$ 4,721.62
	$1,000,000	$ 4,383.00 plus 0.15% of cost in excess of $1,000,000	$ 4,619.00 plus 0.15% of cost in excess of $1,000,000	$1,000,000	10	5.88	$ 2,590.20	$ 3,311.83	$ 5,902.02

Wiring Inspector Hourly Rate
rate including fringe $ 44.03

Overhead rates:		
	Administrative O/H	77%
	Vehicle O/H	51%
	Fringe	18.0%

* includes travel time, training etc.

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.2	New installations: minimum inspection fees			Based on Fee schedule and assumptions noted above
	Residential - all installations	$131.00	$138.00	Based on Fee schedule for installed value of $2,001 - $4,000
	Commercial/Industrial institutional:			
	Up to 100 AMPS	$131.00	$138.00	Based on Fee schedule for installed value of $2,001 - $4,000
	Over 100 to 400 AMPS	$313.00	$330.00	Based on Fee schedule for installed value of $8,001 - $10,000
	Over 400 to 800 AMPS	$438.00	$462.00	Based on Fee schedule for installed value of $10,001 - $15,000
	Over 800 to 1000 AMPS	$556.00	$586.00	Based on Fee schedule for installed value of $15,001 - $25,000
	Over 1000 AMPS	$805.00	$848.00	Based on Fee schedule for installed value of $25,001 - $50,000

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates	Amount	
7.2 g)	Hourly Rate inspections			Key Assumptions for this section:		
				Wiring inspector rate plus fringe	$44.03	
				Regular Labour A/O	$33.99	77.2%
				Overtime A/O		38.6%
				Vehicle A/O	$22.31	50.7%
				Overtime vehicle A/O		25.3%
				Total rate (regular hours) including A/O	$100.33	
				Labour Efficiency (travel, training, etc.)	85%	
				Effective hourly rate	$118.04	
	Normal Working Hours:			**Normal Working Hours**		
	i) *For the first hour or fraction thereof*	$ 64.00	$ 67.00	*For the first hour or fraction thereof:*		
	ii) *For each additional half-hour or fraction thereof*	$ 27.00	$ 28.00	Hourly rate charge	$118.04	
				For each additional half-hour or fraction thereof:		
				Charge rate (50% of hourly rate above)	$59.02	
	Outside Normal Working Hours Extension of a regular working day (before or after)			**Outside Normal Working Hours** Extension of a regular working day (before or after)		Labour efficiency not applied
	i) *For the first hour or fraction thereof:*	$ 86.00	$ 91.00			
	ii) *For each additional half-hour or fraction thereof:*	$ 37.00	$ 39.00	*For the first hour or fraction thereof:*		as covered under normal work day
				Labour (double time)	$88.07	
				A/O	$33.99	38.6%
				Vehicle A/O	$22.31	25.3%
				Hourly rate charge	$144.37	
				For each additional half-hour or fraction thereof:		
				Labour (1/2 hour)	$44.03	
				Overheads	28.15	
				Charge rate	$72.18	
	Weekends and Statutory Holidays Scheduled inspections on weekends (Saturday, Sunday and statutory holidays:			Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:		Labour efficiency not applied as covered under normal work day
				Minimum Fee:		Minimum call-out is 4 hours based on provisions of the Collective Agrrement
	i) *Minimum Fee:*	$ 143.00	$ 151.00	Labour	$176.13	
	ii) *For each additional half-hour above 4 hours*	$ 51.00	$ 54.00	A/O	$135.96	77.2%
				Vehicle A/O	$89.25	50.7%
				Hourly rate charge	$401.34	
				For each additional half-hour above 4 hours		
				Labour (1/2 hour)	$44.03	
				Overheads	28.15	
				Charge rate	$72.18	

Regulation 7.3 Schedule of Load Research, Monitoring, Reporting and Analytical Charges - Proposed Rates for 2014

Regulation Section	Description	Current Rate	Proposed Rate (rounded)	Assumptions supporting Proposed Rates
7.3 Section 1.0	Schedule of load research charges One rate for all equipment types Bi-monthly Monthly	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter	Subsection 1.0 **Recovery of Capital Cost of Meter Equipment**
7.3 Section 2.0	Recovery of Installation Charges Single Phase Service, Self-Contained Single Phase Service, Transformer Rated Three Phase Service	 $ 42.00 $ 113.00	 $ 44.00 $ 119.00	Subsection 2.0 **Recovery of Installation charges** **Single Phase-Self Contained** Labour [redacted] CSFR for 0.5 hours Fringe 18.0% Administrative Overhead 77% Vehicle Overhead 51% Sub-total [redacted] Mark up (internal costs) $ 9.32 25% based on 7.3 b) and c) Charge for service [redacted] **Three Phase** installation charge: Labour [redacted] Three phase meter person for 1 hour Fringe 18.0% Administrative Overhead 77% Vehicle Overhead 51% Sub-total [redacted] Mark up [redacted] 25% based on 7.3 b) and c) Charge for service [redacted] Note: Determined no longer necessary to distinguish between single phase self-contained and single phase transformer rated When organized and paid for by NSPI, recovery of telephone line installation charges will be at cost.
3.0	Recovery of Operational Charges Toll Free Phone Line Operation	 $ 188.00	 $ 186.00	Subsection (new) 3.0 **Recovery of Operational Charges** Average Weighted Call Time 2 minutes Long Distance Charges $0.02 per minute Cost of Capital (WACC) 7.83% Call attempts Per Year 365 Long Distance Charges $186.46
4.0	Load Research Setup	$ 45.00	$ 47.00	Subsection 3.0 **Load research set-up** Labour [redacted] Meter Data Technologist (.75 hrs),Meter Engineer (.25 hrs) Fringe 18.0% Non-union Administrative Overhead 77% Sub-total [redacted] Mark up 25% based on 7.3 b) and c) Charge for service
6.0	Specialized Analysis Hourly rate	 $ 78.00	 $ 80.00	Subsection 5.0 **Specialized Analysis** Labour [redacted] Meter Data Technologist (1 hr) - estimated labour rate Fringe 18.0% Non-union Administrative Overhead 77% Sub-total [redacted] Mark up 25% based on 7.3 b) and c) Charge for service per hour

Proposed Regulation

2013 Regulations – Rate Stabilization

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.1 SCHEDULE OF CHARGES

The following charges shall apply:

(a)	Connection or reconnection of electric service, whether metered or unmetered, to any premises during the Company's normal working hours.	$27.00 standard charge
(b)	Connection or reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is not a reconnection for non payment.	$27.00 standard charge plus $71.00 charge for additional costs.
(c)	Reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is a reconnection associated with non payment.	$27.00 standard charge plus $71.00 charge for additional costs.
(d)	Connection or reconnection of electric service to any premises serviced by temporary service in accordance with these Regulations.	$27.00 standard charge plus all other costs incurred by the Company in connecting or reconnecting service
(e)	Disconnection-Seasonal Electric Service	$28.00 standard charge
(f)	Returned Cheque Charge	$22.00
(g)	Interest on Overdue Accounts	1.5% per month or part thereof, or a maximum of 19.56% per annum
(h)	Interest on Deposits	Interest Rate based on Royal Bank prime rate minus 1%; set January 1st of each year

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.1 SCHEDULE OF CHARGES

(i)	Dispute Test Fee re satisfactory meter	$36.00
(j)	Standard Contribution for three-phase service 15 kW and under	$1,170.00
(k)	Charge for installation of Recording Equipment	
	• 240 volt single phase voltage recorder	$25.00
	• all other recording equipment	Actual Costs incurred by the Company
(l)	Service Charge for any miscellaneous requests.	Actual Costs incurred by the Company
(m)	All pole attachments for telecommunication common carriers, or broadcasters, exclusive of those under joint use agreements.	$14.15 per pole per year
(n)	Access to NSPI Mobile Radio Network	Monthly Charge
	- Basic Dispatch Service	$26.00
	- Individual/Group Call Feature	$21.00
	- Networking Features	$11.00
	- Interconnect Facility (PSTN) Access	$41.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.1 Permits and Inspections

Permits and inspections will normally be of three types:
a) Regular Permits and Inspections
b) Annual Permits and Inspections
c) Special Permits and Inspections

a) **Regular Permits and Inspections**

All persons, firms or corporations within Nova Scotia Power's inspection authority who are eligible to install electrical installations for the use of electrical energy shall, before commencing or doing any electrical installation of new equipment, or repairs, or altering or adding to any electrical installation or equipment already installed, submit and obtain approval in a manner prescribed by the inspection authority.

Individual permits shall be required for temporary and individual miscellaneous services and each dwelling unit of a single, duplex or row type housing, etc., whether supplied via an individual or multi-position metering devices.

Apartment type buildings, multi-tenant industrial and commercial installations shall be performed under one permit.

Permits are not transferable.

Permits shall be issued only to the firm or persons performing the work described on the Permit and in compliance with Section 4, "Permit" of the regulations made by the Fire Marshall pursuant to the Electrical Installation and Inspection Act.

Permit holders shall immediately notify the Electrical Inspection Authority upon the completion of an electrical installation requesting a FINAL inspection.

The fee for a Regular Permit and Inspection will be based on the Installed Value, including labour, material and sundries of the electrical installation, alteration, upgrade, repair or extension.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

When a dispute arises regarding the cost of an electrical installation the permit applicant may be required, at the Inspection Authority discretion, to supply a letter from the owner indicating the value of the contract and/or a bill of materials for the project.

The fees for a Regular Permit and Inspection, including the number of Inspection Visits, shall be based on the Installed Value of the installation as shown in the Inspection Fee Schedule.

b) **Annual Permits and Inspections**

An annual maintenance permit shall be issued for an establishment to cover all minor repairs as required under sections 4(a) (B), (2) and (3) of the regulations made by the Fire Marshal pursuant to the Electrical Installation Act.

Such a permit does not entitle the holder to effect major electrical alterations or additions.

The number of inspection visits shall be at the discretion of the Inspection Authority. Notwithstanding the above, at least one inspection visit shall be made in the year for which the permit is issued.

c) **Special Permits and Inspections**

Where the fee for a Regular Permit and Inspection are inappropriate the special permit and inspection fee shall apply. (Ex. carnivals and travelling shows).

7.2.2 **Late Application Fee**

Where an electrical contractor fails to obtain an electrical wiring permit prior to commencing the electrical work, an additional fee shall be payable in the amount of fifty (50) percent of the regular fee, up to a maximum additional fee of $100.00.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.3 **Payment of Fees**

Fees for permits and inspections shall be paid at the time of requesting the permit unless otherwise indicated by the inspection authority. Permits having fees in arrears in excess of 120 days shall be subject to cancellation and at the discretion of the inspection authority, no additional permits shall be issued to the holder of the unpaid permits until such time the outstanding fees have been adequately dealt with.

7.2.4 **Refund of Fees**

The holder of a permit may apply to the inspection authority for a refund less a $10.00 non-refundable portion of the permit fee with respect to a cancelled or unused permit. No refund shall be issued for a permit where an inspection call has been made at the request of the permit holder.

7.2.5 **Expiry of Permits**

A permit for electrical work is valid for 12 months from the date of issue in respect of residential and 24 months in respect of all others unless otherwise noted on the permit. Upon expiry, a renewal fee to a maximum of 50% of the cost of the original permit shall be charged.

7.2.6 **Review of Plans and Specifications**

The Inspection Authority may, prior to issuing a permit, request the submission of plans and specifications for any proposed electrical installation. Plans shall be submitted for all commercial, industrial institutional installations exceeding 250 volts or 250 amperes.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.7 Inspection Fee Schedule

a) **Regular Permits and Inspection**

The fee for a regular permit and the maximum number of inspection visits, with respect to an installation will be calculated, as follows.

b) **Annual Permit and Inspection**

The fee for an annual permit and inspection for any one establishment shall be the appropriate hourly rate.

c) **Special Permit and Inspection**

The fee for a special permit and inspection for any one project shall be the appropriate hourly rate.

d) **Plans Examination**

The fees for the examination of electrical plans and specifications shall be per review:

0 – 1,000 amps	$109.00
Greater than 1,000 amps	$ 109.00

e) **Primary Services**

The fees for the inspection of a primary service (padmount, vault, etc.) shall be per installation.	$124.00

f) **Letter of Acceptance**

The fees for a Letter of Acceptance shall be	$ 32.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

INSPECTION FEE SCHEDULE

INSTALLED VALUE OF ELECTRICAL INSTALLATION	INSPECTION VISITS	PERMIT FEE
$ 0,000 to $ 2,000	1	$ 65.00
$ 2,001 to $ 4,000	2	$ 131.00
$ 4,001 to $ 6,000	2	$ 221.00
$ 6,001 to $ 8,000	2	$ 269.00
$ 8,001 to $ 10,000	2	$ 313.00
$ 10,001 to $ 15,000	3	$ 438.00
$ 15,001 to $ 25,000	3	$ 556.00
$ 25,001 to $ 50,000	3	$ 805.00
$ 50,001 to $ 100,000	3	$1,143.00
$100,001 to $ 300,000	4	$1,793.00
$300,001 to $ 500,000	5	$2,241.00
$500,001 to $750,000	6	$2,690.00
$750,001 to $1,000,000	8	$3,586.00
+ $1,000,000	10	$4,383.00 + 0.15% of cost in excess of $1,000,000

New Installations are subject to the following minimum inspection fees:

RESIDENTIAL-ALL INSTALLATIONS	$131.00
COMMERCIAL/INDUSTRIAL INSTITUTIONAL	
Up to 100 AMPS	$131.00
Over 100 to 400 AMPS	$313.00
Over 400 to 800 AMPS	$438.00
Over 800 to 1000 AMPS	$556.00
Over 1000 AMPS	$805.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

g) **Hourly Rate Inspections**

Note: All fees are per inspection visit.

Normal Working Hours:

i)	For the first hour or fraction thereof	$ 64.00
ii)	For each additional half-hour or fraction thereof..	$ 27.00

Outside Normal Working Hours:

Extension of a regular work day (before or after)

i)	For the first hour or fraction thereof.......	$ 86.00
ii)	For each additional half-hour or fraction thereof..	$ 37.00

Weekends and Statutory Holidays:

Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:

i)	For the first hour or fraction thereof.......	$143.00
ii)	For each additional half-hour or fraction thereof..	$ 51.00

h) **Inspections in Excess of Maximum Number of Visits**

For an inspection visit, in excess of the maximum number of visits permitted under the Regular Permit and Inspection Fee the Special Permit and Inspection Fee shall apply.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORT AND ANALYTICAL CHARGES

The following schedule of charges shall apply to customers requesting Load Research information. **(Note: Customers must provide access to a shared phone line for data collection via automatic meter reading equipment):**

a) **Recovery of the Capital Cost of Installed Equipment** will be the actual costs incurred by the Company.

b) **Setup for Load Research** will be the actual cost incurred by Company plus a 25% markup.

c) **Analysis and Reporting Charges** will be the actual costs incurred by the Company plus at 25% markup.

d) **Specialized Customer Analysis** will be the actual costs incurred by the Company plus at 25% markup.

SCHEDULE OF LOAD RESEARCH CHARGES

		ONE TIME
1.0	**Recovery of Capital Cost of Meter Equipment**	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter.
2.0	**Recovery of Installation Charges**	When organizes and paid by NSPI, recovery of telephone line installation charges will be at cost.

Single Phase Service Self-Contained	$42.00
Single Phase Service, Transformer Rated and Three Phase Service	$113.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORT AND ANALYTICAL CHARGES

3.0	**Recovery of Operational Charges**	$188.00
4.0	**Load Research Setup**	$45.00
5.0	**Analysis and Reporting** **Base Package**	**See Charge per Billing Period**
	Load profile for peak day billing period plus times and magnitude of six highest peaks	33.00
	Options	
	Data File	33.00
	Load profile for each day for each billing period	33.00
	Power factor for plot for peak day (kVA billed cust. only)	33.00
	Power factor plot for each day (kVA billed cust. only)	11.00
	Reports of billing period average load profile for each day of the week	33.00
	Report of billing period average load profile for an specific day of the week	11.00
	Daily summary	11.00
	Monthly summary	11.00
	Weekly or monthly detail	11.00
	Daily comparison: Any two customers specified days	11.00
	Load duration plot	11.00
	Daily consumption plot	11.00
	Complete package (all of the above options)	180.00
6.0	**Specialized Analysis**	
	Hourly Rate	78.00

Proposed Regulation

2014 Regulations – Rate Stabilization

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.1 SCHEDULE OF CHARGES

The following charges shall apply:

(a)	Connection or reconnection of electric service, whether metered or unmetered, to any premises during the Company's normal working hours.	\$28.00 standard charge
(b)	Connection or reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is not a reconnection for non payment.	\$28.00 standard charge plus \$75.00 charge for additional costs.
(c)	Reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is a reconnection associated with non payment.	\$28.00 standard charge plus \$75.00 charge for additional costs.
(d)	Connection or reconnection of electric service to any premises serviced by temporary service in accordance with these Regulations.	\$28.00 standard charge plus all other costs incurred by the Company in connecting or reconnecting service
(e)	Disconnection-Seasonal Electric Service	\$30.00 standard charge
(f)	Returned Cheque Charge	\$23.00
(g)	Interest on Overdue Accounts	1.5% per month or part thereof, or a maximum of 19.56% per annum
(h)	Interest on Deposits	Interest Rate based on Royal Bank prime rate minus 1%; set January 1st of each year

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.1 SCHEDULE OF CHARGES

(i)	Dispute Test Fee re satisfactory meter	$38.00
(j)	Standard Contribution for three-phase service 15 kW and under	$1,233.00
(k)	Charge for installation of Recording Equipment	
	• 240 volt single phase voltage recorder	$25.00
	• all other recording equipment	Actual Costs incurred by the Company
(l)	Service Charge for any miscellaneous requests.	Actual Costs incurred by the Company
(m)	All pole attachments for telecommunication common carriers, or broadcasters, exclusive of those under joint use agreements.	$14.15 per pole per year
(n)	Access to NSPI Mobile Radio Network	Monthly Charge
	- Basic Dispatch Service	$26.00
	- Individual/Group Call Feature	$21.00
	- Networking Features	$11.00
	- Interconnect Facility (PSTN) Access	$41.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.1 Permits and Inspections

Permits and inspections will normally be of three types:

a) Regular Permits and Inspections
b) Annual Permits and Inspections
c) Special Permits and Inspections

a) **Regular Permits and Inspections**

All persons, firms or corporations within Nova Scotia Power's inspection authority who are eligible to install electrical installations for the use of electrical energy shall, before commencing or doing any electrical installation of new equipment, or repairs, or altering or adding to any electrical installation or equipment already installed, submit and obtain approval in a manner prescribed by the inspection authority.

Individual permits shall be required for temporary and individual miscellaneous services and each dwelling unit of a single, duplex or row type housing, etc., whether supplied via an individual or multi-position metering devices.

Apartment type buildings, multi-tenant industrial and commercial installations shall be performed under one permit.

Permits are not transferable.

Permits shall be issued only to the firm or persons performing the work described on the Permit and in compliance with Section 4, "Permit" of the regulations made by the Fire Marshall pursuant to the Electrical Installation and Inspection Act.

Permit holders shall immediately notify the Electrical Inspection Authority upon the completion of an electrical installation requesting a FINAL inspection.

The fee for a Regular Permit and Inspection will be based on the Installed Value, including labour, material and sundries of the electrical installation, alteration, upgrade, repair or extension.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

When a dispute arises regarding the cost of an electrical installation the permit applicant may be required, at the Inspection Authority discretion, to supply a letter from the owner indicating the value of the contract and/or a bill of materials for the project.

The fees for a Regular Permit and Inspection, including the number of Inspection Visits, shall be based on the Installed Value of the installation as shown in the Inspection Fee Schedule.

b) **Annual Permits and Inspections**

An annual maintenance permit shall be issued for an establishment to cover all minor repairs as required under sections 4(a) (B), (2) and (3) of the regulations made by the Fire Marshal pursuant to the Electrical Installation Act.

Such a permit does not entitle the holder to effect major electrical alterations or additions.

The number of inspection visits shall be at the discretion of the Inspection Authority. Notwithstanding the above, at least one inspection visit shall be made in the year for which the permit is issued.

c) **Special Permits and Inspections**

Where the fee for a Regular Permit and Inspection are inappropriate the special permit and inspection fee shall apply. (Ex. carnivals and travelling shows).

7.2.2 **Late Application Fee**

Where an electrical contractor fails to obtain an electrical wiring permit prior to commencing the electrical work, an additional fee shall be payable in the amount of fifty (50) percent of the regular fee, up to a maximum additional fee of $100.00.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.3 Payment of Fees

Fees for permits and inspections shall be paid at the time of requesting the permit unless otherwise indicated by the inspection authority. Permits having fees in arrears in excess of 120 days shall be subject to cancellation and at the discretion of the inspection authority, no additional permits shall be issued to the holder of the unpaid permits until such time the outstanding fees have been adequately dealt with.

7.2.4 Refund of Fees

The holder of a permit may apply to the inspection authority for a refund less a $10.00 non-refundable portion of the permit fee with respect to a cancelled or unused permit. No refund shall be issued for a permit where an inspection call has been made at the request of the permit holder.

7.2.5 Expiry of Permits

A permit for electrical work is valid for 12 months from the date of issue in respect of residential and 24 months in respect of all others unless otherwise noted on the permit. Upon expiry, a renewal fee to a maximum of 50% of the cost of the original permit shall be charged.

7.2.6 Review of Plans and Specifications

The Inspection Authority may, prior to issuing a permit, request the submission of plans and specifications for any proposed electrical installation. Plans shall be submitted for all commercial, industrial institutional installations exceeding 250 volts or 250 amperes.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.7 Inspection Fee Schedule

a) **Regular Permits and Inspection**

The fee for a regular permit and the maximum number of inspection visits, with respect to an installation will be calculated, as follows.

b) **Annual Permit and Inspection**

The fee for an annual permit and inspection for any one establishment shall be the appropriate hourly rate.

c) **Special Permit and Inspection**

The fee for a special permit and inspection for any one project shall be the appropriate hourly rate.

d) **Plans Examination**

The fees for the examination of electrical plans and specifications shall be per review:

0 – 1,000 amps	$ 115.00
Greater than 1,000 amps	$ 115.00

e) **Primary Services**

The fees for the inspection of a primary service (padmount, vault, etc.) shall be per installation. $124.00

f) **Letter of Acceptance**

The fees for a Letter of Acceptance shall be .... $ 32.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

INSPECTION FEE SCHEDULE

INSTALLED VALUE OF ELECTRICAL INSTALLATION	INSPECTION VISITS	PERMIT FEE
$ 0,000 to $ 2,000	1	$ 68.00
$ 2,001 to $ 4,000	2	$ 138.00
$ 4,001 to $ 6,000	2	$ 233.00
$ 6,001 to $ 8,000	2	$ 283.00
$ 8,001 to $ 10,000	2	$ 330.00
$ 10,001 to $ 15,000	3	$ 462.00
$ 15,001 to $ 25,000	3	$ 586.00
$ 25,001 to $ 50,000	3	$ 848.00
$ 50,001 to $ 100,000	3	$1,204.00
$100,001 to $ 300,000	4	$1,889.00
$300,001 to $ 500,000	5	$2,362.00
$500,001 to $750,000	6	$2,835.00
$750,001 to $1,000,000	8	$3,779.00
+ $1,000,000	10	$4,619.00
		+ 0.15% of cost in excess of $1,000,000

<u>New Installations</u> are subject to the following <u>minimum</u> inspection fees:

RESIDENTIAL-ALL INSTALLATIONS	$138.00
COMMERCIAL/INDUSTRIAL INSTITUTIONAL	
Up to 100 AMPS	$138.00
Over 100 to 400 AMPS	$330.00
Over 400 to 800 AMPS	$462.00
Over 800 to 1000 AMPS	$586.00
Over 1000 AMPS	$848.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

g) **Hourly Rate Inspections**

Note: All fees are per inspection visit.

Normal Working Hours:

i)	For the first hour or fraction thereof	$ 67.00
ii)	For each additional half-hour or fraction thereof...	$ 28.00

Outside Normal Working Hours:
Extension of a regular work day (before or after)

i)	For the first hour or fraction thereof.......	$ 91.00
ii)	For each additional half-hour or fraction thereof...	$ 39.00

Weekends and Statutory Holidays:
Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:

i)	For the first hour or fraction thereof.......	$151.00
ii)	For each additional half-hour or fraction thereof...	$ 54.00

h) **Inspections in Excess of Maximum Number of Visits**

For an inspection visit, in excess of the maximum number of visits permitted under the Regular Permit and Inspection Fee the Special Permit and Inspection Fee shall apply.

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORT AND ANALYTICAL CHARGES

The following schedule of charges shall apply to customers requesting Load Research information. **(Note: Customers must provide access to a shared phone line for data collection via automatic meter reading equipment):**

a) **Recovery of the Capital Cost of Installed Equipment** will be the actual costs incurred by the Company.

b) **Setup for Load Research** will be the actual cost incurred by Company plus a 25% markup.

c) **Analysis and Reporting Charges** will be the actual costs incurred by the Company plus at 25% markup.

d) **Specialized Customer Analysis** will be the actual costs incurred by the Company plus at 25% markup.

SCHEDULE OF LOAD RESEARCH CHARGES

		ONE TIME
1.0	**Recovery of Capital Cost of Meter Equipment**	The capital costs of metering equipment to be recovered will be the incremental cost of the AMR meter installed compared to an equivalent non-AMR meter.
2.0	**Recovery of Installation Charges**	When organizes and paid by NSPI, recovery of telephone line installation charges will be at cost.
	Single Phase Service Self-Contained	$44.00
	Single Phase Service, Transformer Rated and Three Phase Service	$119.00

NOVA SCOTIA POWER INCORPORATED

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORT AND ANALYTICAL CHARGES

3.0	**Recovery of Operational Charges**	$186.00
4.0	**Load Research Setup**	$47.00
5.0	**Analysis and Reporting**	**See Charge per Billing Period**
	Base Package	
	Load profile for peak day billing period plus times and magnitude of six highest peaks	33.00
	Options	
	Data File	33.00
	Load profile for each day for each billing period	33.00
	Power factor for plot for peak day (kVA billed cust. only)	33.00
	Power factor plot for each day (kVA billed cust. only)	11.00
	Reports of billing period average load profile for each day of the week	33.00
	Report of billing period average load profile for an specific day of the week	11.00
	Daily summary	11.00
	Monthly summary	11.00
	Weekly or monthly detail	11.00
	Daily comparison: Any two customers specified days	11.00
	Load duration plot	11.00
	Daily consumption plot	11.00
	Complete package (all of the above options)	180.00
5.0	**Specialized Analysis**	
	Hourly Rate	80.00

CHANGE TO ACCOUNTING POLICY 5900

The Board's March 20, 2012 letter declines NS Power's request to revise Accounting Policy 5900. On April 5, 2012, NS Power requested the Board to reconsider its original decision in light of further information provided. On May 4, 2012, the Board approved a suspension of the regulatory recovery applicable to the deferral of fixed costs for 2012 and indicated, "The continuation of the suspension for this (if needed), or any other regulatory deferral, should be an issue canvassed at a future proceeding. This approval of the suspension does not include the proposed wording of the amendment to accounting policy 5900."[1]

NS Power now seeks a permanent change to Accounting Policy 5900 to apply to the fixed cost deferral sought in this Application.

The requested change to the accounting policy will help to prevent the need to seek future additional recovery from NS Power's customers. Without the requested change, NS Power will need to seek higher rates in the future in order to fully recover both the deferral and the tax implications of that recovery. Under the existing accounting policy, prior to the Board's approval of the suspension of the regulatory recovery applicable to the deferral of fixed costs in 2012, the tax treatment of the deferral would have required NS Power to record increased earnings in 2012, and drive the need for higher rates in future due to higher income tax expense when the deferral is being recovered.

The following tables will help to illustrate how the change in accounting policy affects customers.

[1] NSPI Request for Reconsideration of Decision Dated March 20, 2012 Regarding Amendments to Accounting Policy 5900 – Income Taxes (Formerly Matter No. M04760) (P-111.6/Matter No. M04895), UARB Correspondence, May 4, 2012.

<u>No change to Accounting Policy</u>

The income statement impact if the Board had not suspended the provisions of the Accounting Policy for the 2012 FCR is shown in the table below. For illustration purposes, this assumes the deferral in 2012 equates to $30 million and the deferral is fully recovered in 2013. We expect the deferral to be higher than $30 million. The 2013 revenue requirement amounts are not tax-effected in this illustration, which exacerbates the situation.

(Millions of Dollars)	2012	Comment	2013	Comment
Revenue	(30)	Revenue not collected in 2012 but deferred	30	Deferred revenue collected in 2013
Fixed Cost adjustment	30		(30)	
Income tax expense (recovery)	(9.3)	Tax deduction available $30M * 31%	9.3	
Earnings	9.3	Additional earnings not presently incorporated in 2012 forecast	(9.3)	Additional expense that will need to be recovered as a 2013 cost of service

With 2012 rates already set, NS Power would have recorded an additional $9.3 million in earnings (more when the deferral is higher than $30 million). In the 2013 test year, NS Power would experience an additional $9.3 million income tax expense which will increase the requested revenue requirement in 2013 by $13.5 million (more when the deferral amount is higher than the $30 million used for illustrative purposes).

<u>Approval of NS Power Application</u>

The suspension of the accounting policy provisions for the 2012 Fixed Cost Recovery have allowed the recording of deferred taxes then the earnings volatility is removed and customers are fairly treated with no impact to rates in either year. The impact would be as follows:

(Millions of Dollars)	2012	Comment	2013	Comment
Revenue	(30)	Revenue not collected in 2012 but deferred	30	Deferred revenue collected in 2013
Fixed Cost adjustment	30		(30)	
Income tax expense (recovery)	(9.3)	Tax deduction available $30M * 31%	9.3	
Deferred income tax expense	9.3	Deferred income tax calculation of $30M * 31%	(9.3)	Deferred income tax calculation $30M * 31%
Earnings	NIL	No change to earnings	NIL	No change to earnings

With a permanent change to Accounting Policy 5900, this same treatment will be used for the proposed continuation of the Fixed Cost Deferral for 2013 and 2014.

The proposed accounting policy change has no bearing on how the deferral works, the amount of the deferral, or any matter relating to the deferral other than ensuring that the tax effect will match the accounting for the deferral (whatever amount it ends up to be and whatever the time period for recovery may be). Our proposal is an effort to help customers and remove any complication that may arise in the treatment of this regulatory accounting item. And it is exactly the accounting approach the Board has previously approved for the FAM.

Below is a tracked change version as well as a clean version of Accounting Policy 5900 – Income taxes.

Nova Scotia POWER
An Emera Company

COST OF OPERATIONS

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM and the deferral of any unrecovered contributions to fixed costs as approved by the Nova Scotia Utility and Review Board ("the deferral"). Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM and the deferral will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM and the deferral regulatory asset (liability) ~~is~~ are expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

COST OF OPERATIONS

INCOME TAXES - 5900

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes, including net Part VI.1 tax, are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067. ~~The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.~~

COST OF OPERATIONS

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM and the deferral of any unrecovered contributions to fixed costs as detailed in the 2012 General Rate Application Settlement Agreement as approved by the Nova Scotia Utility and Review Board on the 29th November 2011 ("the deferral"). Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM and the deferral will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM and the deferral regulatory asset (liability) are expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes, including net Part VI.1 tax, are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067.