



**Buying Group**

# **Electricity Procurement Strategy**

## **Executive Summary**

**for**

## **The Town of Ingersoll**

**June 14, 2010**

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## Summary of 2009 Results

The financial world has gone through significant changes over the past year and the Ontario electricity market has not been immune. Electricity spot market prices (nominal prices) are at an all time low and yet the prices consumers are charged (effective prices) for electricity is at an all-time high. In absolute dollar terms the Town's cost of electricity in 2009 was slightly more than its cost in 2008 (\$6,000 increase), however, this does not speak to the effectiveness of WattsWorth's strategy. In 2008 the Town was in the government sponsored electricity procurement program called the Regulated Price Protection (RPP) Plan for most of the year. The RPP rate in 2008 was set well below the cost of electricity in order to return to rate payers the excess funds that the program had been collecting as compared to the actual cost of electricity. Of these excess funds, the Town paid a greater proportion than it received back. WattsWorth's recommendation to the Town in late 2008 was in anticipation of a sharp increase in the RPP rates once the surplus had been fully expended. As expected the RPP rose by 15% from the then 5.8¢ per kWh in 2008 to the now 6.7¢ per kWh. By utilizing WattsWorth's procurement strategy the Town's effective 2009 cost of electricity was 5.87¢ per kWh. Thus, although the Town's cost of electricity commodity (electricity cost plus Provincial Benefit charge) rose slightly from 2008 to 2009, WattsWorth's strategy managed to avoid an additional cost to the Town of \$23,000 that it would have had to pay had it remained in the RPP and absorbed the 15% increase in electricity rates.

On May 1, 2010 the RPP rates rose by 12% from 6.7¢ per kWh to 7.5¢ per kWh to reflect the impact of the Provincial Benefit cost. Because the Town of Ingersoll is no longer part of this program WattsWorth's strategy will successfully avoid this increase which amounts to an avoided cost of \$52,000.

In early 2009 it was very difficult to anticipate the net impact that the global financial crisis would have on the electricity market. At that time WattsWorth expected the depressed electricity demand would result in very low electricity spot market prices but increased volatility. The strategy that was proposed expected to return a unit cost of about 5.8¢ per kWh, which was effectively holding the Town's electricity cost near the 2008 levels. The resulting 5.87¢ per kWh actual unit cost was achieved in spite of the direct result of a 454% increase in the Provincial Benefit Charge (2008 average \$5.31/MWh vs. 2009 average \$29.31/MWh). The Provincial Benefit impacts all electricity procurement programs equally and is expected to drive up the RPP cost of electricity even higher than those experienced today. With hindsight, WattsWorth can see that the drastic increase in the Provincial Benefit cost is the greatest risk to electricity consumers in Ontario when the spot market price of electricity falls. This impact has become part of WattsWorth's strategy recommendations going forward.

Town of Ingersoll financial summary for 2009:

Date	kWh	Strategy Cost	RPP Base Cost	Difference	
				\$	%
Jan-09	451,790	\$ 29,013	\$ 29,260	\$ (247)	-0.8%
Feb-09	392,819	\$ 20,284	\$ 25,421	\$ (5,137)	-20.2%
Mar-09	391,482	\$ 14,884	\$ 25,328	\$ (10,444)	-41.2%
Apr-09	309,118	\$ 14,295	\$ 19,985	\$ (5,689)	-28.5%
May-09	276,410	\$ 18,404	\$ 18,132	\$ 272	1.5%
Jun-09	286,557	\$ 14,583	\$ 18,803	\$ (4,220)	-22.4%
Jul-09	278,888	\$ 15,378	\$ 18,305	\$ (2,927)	-16.0%
Aug-09	296,231	\$ 20,583	\$ 19,435	\$ 1,148	5.9%
Sep-09	349,155	\$ 19,086	\$ 22,936	\$ (3,850)	-16.8%
Oct-09	371,309	\$ 26,272	\$ 24,394	\$ 1,878	7.7%
Nov-09	380,266	\$ 22,949	\$ 25,362	\$ (2,413)	-9.5%
Dec-09	418,496	\$ 31,131	\$ 27,918	\$ 3,213	11.5%
<b>Total 2009</b>	<b>4,202,521</b>	<b>246,862</b>	<b>275,279</b>	<b>(28,417)</b>	<b>-10.3%</b>

Of the procurement options available to it in 2009, WattsWorth's strategy for the Town has proven to be most optimal for balancing risk and cost.

### Strategy Proposal – May 2010 to April 2011

Ontario's electricity market has not much changed since the strategy developed for the Town in 2009. It is for this reason that WattsWorth's recommends the Town utilize the current contract that was purchased in 2009 for 2010-11 and not purchase any additional contract volume.

Economic analysis indicates that the current market conditions will remain through to the middle of 2011 making the current strategy optimal for the Town. If conditions change for the Town, WattsWorth will contact you and propose alternatives if required.

### 2010 Electricity Summary

Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Hedge "A"										
Hedge "B"	\$ 50.82	\$ 55.38	\$ 62.89	\$ 66.24	\$ 67.92	\$ 195,079	\$ 221,701	\$ 270,801	\$ 314,081	\$ 327,911
Hedge "C"	\$ 49.56	\$ 54.44	\$ 62.73	\$ 66.58	\$ 68.25	\$ 185,944	\$ 212,435	\$ 270,108	\$ 318,517	\$ 332,425
Hedge "D"	\$ 49.03	\$ 53.53	\$ 62.66	\$ 66.71	\$ 68.39	\$ 179,152	\$ 204,432	\$ 269,811	\$ 321,915	\$ 335,892
Base	\$ 48.90	\$ 53.30	\$ 62.57	\$ 66.62	\$ 68.30	\$ 176,876	\$ 201,942	\$ 269,416	\$ 322,147	\$ 336,121
RPP 2010	\$ 74.60	\$ 74.64	\$ 74.67	\$ 74.68	\$ 74.69	\$ 285,879	\$ 298,859	\$ 321,483	\$ 350,464	\$ 356,951
Actual 2009			\$ 58.74					\$ 246,862		

Utilizing WattsWorth's 2010-11 strategy the Town's unit cost of electricity is expected to be \$62.57 per MWh (6.26¢ per kWh). This represents an increase of 6.5 % over the Town's 2009 cost of electricity. This increase in electricity cost to the Town is the direct result of the Provincial Benefit. WattsWorth's strategy for the Town will avoid a \$52,000 increase in its cost had it remained in the RPP. Because the Provincial Benefit cannot be managed it cannot be avoided using alternative procurement options. Until the economy returns to "normal" the Provincial Benefit will represent the largest cost of electricity consumers in Ontario.

**Next Steps:**

1. WattsWorth will be moving your electricity accounts from Shell Energy Trading to Direct Energy in mid-April. If the process is accomplished seamlessly then there will be no impact on the Town.
2. WattsWorth will continue to monitor the electricity market to ensure the current strategy is the optimal one and propose changes where required.



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# **Electricity Market Outlook**

**for**

**The Town of Ingersoll**

**June 14, 2010**

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## **Electricity Market Outlook - November 2009 to April 2011**

Since market opening in 2002, the nominal hourly spot market price has been determined by the balance between electricity supply and demand and the input fuel cost for generation. It was hoped at that time that the “invisible hand” of the market would provide incentives for the building of generation as well as conservation and demand management. These market incentives were intended to be the spot market price for electricity that generators competed to provide. Unfortunately, the market prices that resulted were too high which proved to be politically untenable. In response, the Provincial government devised a number of programs to “manage” the cost of electricity and established a host of agencies to fill the roles vacated by the market. Both the agencies and the programs are explained below as both have a significant impact on the cost of electricity and risk to Ontario consumers.

### **Ontario Electricity Market Agencies**

#### **The Ministry of Energy (MOE)**

The Ministry of Energy is a government body that sets the future course for Ontario’s energy markets by defining legislation and market rules that apply to all entities in the market. The MOE is headed by politicians that are elected every three to four years. The MOE’s policies emulate the prevailing political party in power at the time.

#### **The Ontario Energy Board (OEB)**

The OEB oversees all aspects of the electricity market and ensures that the rules defined by the MOE are enforced. Although the OEB is arms-length from the MOE, its chair is appointed by the political party that is in power. One of the OEB’s primary responsibilities is to approve rate increases that local utilities apply for each year.

#### **The Ontario Power Authority (OPA)**

The OPA is a relatively new agency that was designed by the MOE to ensure that Ontario’s long-term electricity needs are going to be met with new generation, transmission, and conservation. The OPA’s most familiar programs include Demand Response and Feed-In-Tariffs for wind and solar generation. A lesser known role for the OPA is to guarantee revenues for large natural gas generators such as Portlands, Goreway, Sythe-Global, and the Greater Toronto Airport Authority (GTAA). The structure and reporting of the OPA is very similar to the OEB. Although the OPA is arms-length from the MOE, its chair is appointed by the prevailing political party and its direction comes from the MOE. The OPA does not report to the OEB.

#### **The Independent Electricity Systems Operator (IESO)**

The IESO is the agency that ensures that actual market demand is met by available supply. The IESO will dispatch generators across the Province to ensure that the lights do not go out. In addition to balancing supply

and demand, the IESO invoices large electricity consumers for the electricity consumed and remits funds to each entitled party. The IESO is completely separate from the MOE.

### Local Distribution Companies (LDC)

The LDC is the organization in your community that provides each metered customer with electricity. LDC's maintain the electrical distribution service and invoice monthly for electricity. Rates for the LDC are set by the OEB each year.

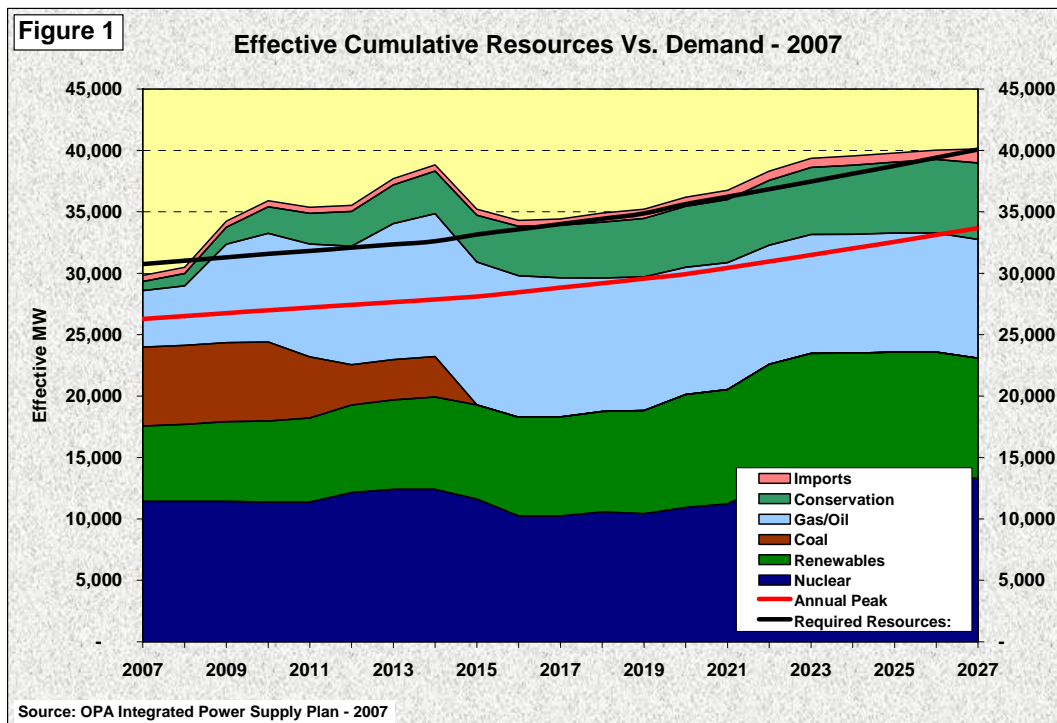
### Nominal Versus Effective Electricity Prices

The nominal hourly spot market cost of electricity represents what generators are actually paid to generate electricity. The effective electricity rate that consumers in Ontario actually pay is the nominal rate adjusted by government programs that reduce market volatility and fund conservation and renewable electricity generation. The following WattsWorth analysis will provide insight into both the nominal and effective electricity market so as to better highlight your risk and help choose your strategy for electricity procurement.

### The Nominal Electricity Price

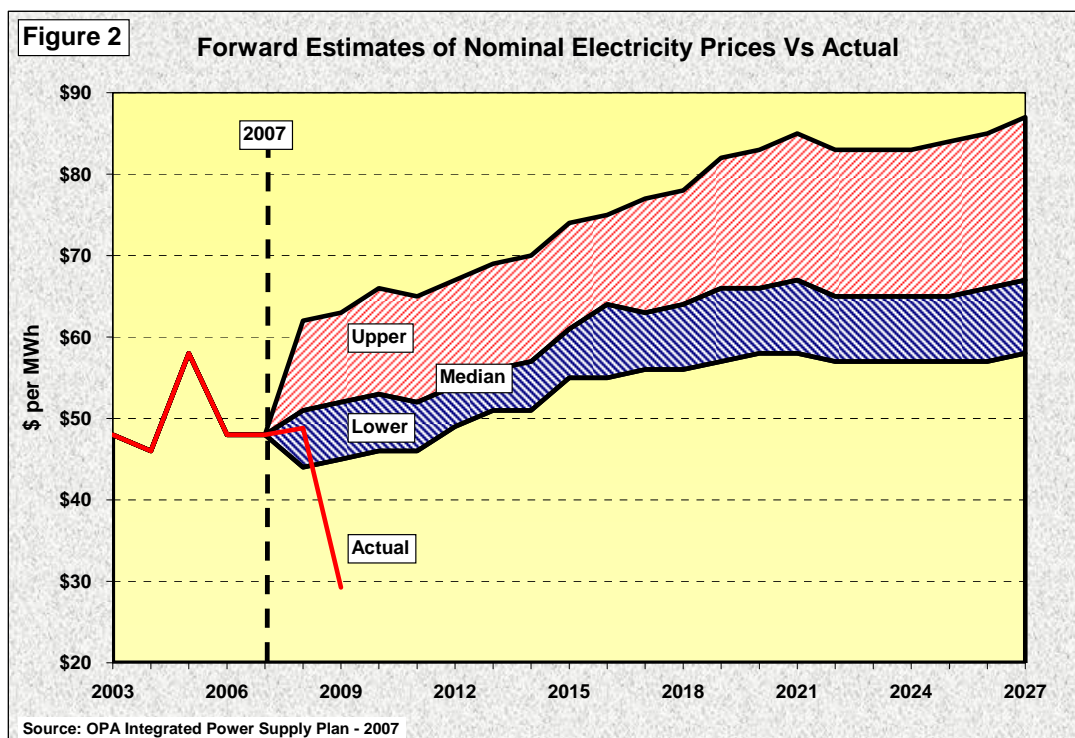
#### Supply and Demand

Ontario's generation fuel mix is much diversified and includes hydraulic, nuclear, coal, natural gas, oil, and renewable energy (wind, biomass). One of the prime responsibilities of the Ontario Power Authority (OPA) is to chart a future course for Ontario to ensure that future electricity supply will meet demand. In September 2007, the Ontario Power Authority (OPA) published the Integrated Power Supply Plan (IPSP) which highlights the then expected supply and demand balance for the next 15 years (**Figure 1** below):



At the time that this report was produced the economy was red-hot and growing at 3% annually. Demand for all input fuels was very high. So too was the demand for electricity to fuel Ontario's economic engine. The IPSP confirms that even when the system is stressed by demand it is still capable of meeting Ontario's needs well into the future. But based on the principles of supply and demand, Ontario's nominal electricity price would rise at a similar pace as more expensive forms of generation (natural gas, wind, solar) were employed to meet demand.

The current market situation is far from that which was expected. The demand destruction that was caused by manufacturers scaling back production or shuttering completely has driven down demand and left the Province awash in cheap electricity. The principles of supply and demand have resulted in very low nominal electricity prices (red line in **Figure 2**). The chart in **Figure 2** below compares the expected IPSP price of electricity based on the assumptions at the time of its production (2007) and the actual nominal price of electricity that has resulted from the economic crisis.



The above chart reflects what generators in Ontario are paid for electricity. This however does not reflect what Ontario electricity consumers' actual pay for electricity. The effective cost of electricity to Ontario consumers is described below.

**The Effective Electricity Price**

In addition to ensuring that supply meets demand the OPA is also responsible to transform Ontario into a “green” (low-carbon emitting) electricity generating Province. As is evident from the graph in **Figure 1** above, the OPA expects to:

- i. Eliminate coal generation by 2014 and replace it with renewable generation like wind, biomass, and solar;
- ii. Provide incentives to reduce demand by 5,000 MW before the coal plants are shuttered;
- iii. Contract with enough natural gas generating companies to fulfill any shortfalls created by the loss of coal generation and/or the shortfall in conservation.

The OPA moved forward with these initiatives utilizing the same assumptions of high demand and economic growth that underlie the IPSP and the resulting average nominal spot market price of \$60 to \$70 per MWh as highlighted in **Figure 2**. The reality of the global financial crisis has reduced demand for all commodities including electricity. The OPA's contracts and incentives that were once "in-the-money" are now well "out-of-the-money". The consequence for Ontario's electricity consumers is that:

- i. Ontario can confidently close its coal plants well in advance of 2014;
- ii. Incentives for demand reduction and conservation are being paid to participants even though the Province is flush with generation;
- iii. The OPA has signed revenue guarantees with natural gas and renewable generators that pay high prices for electricity that isn't even generated.

Ontario is experiencing the lowest nominal electricity prices in its history but some of the highest effective costs on their invoices due to items i and ii above. These costs are reported on each Ontario consumers' electricity invoice as a line item called the Provincial Benefit.

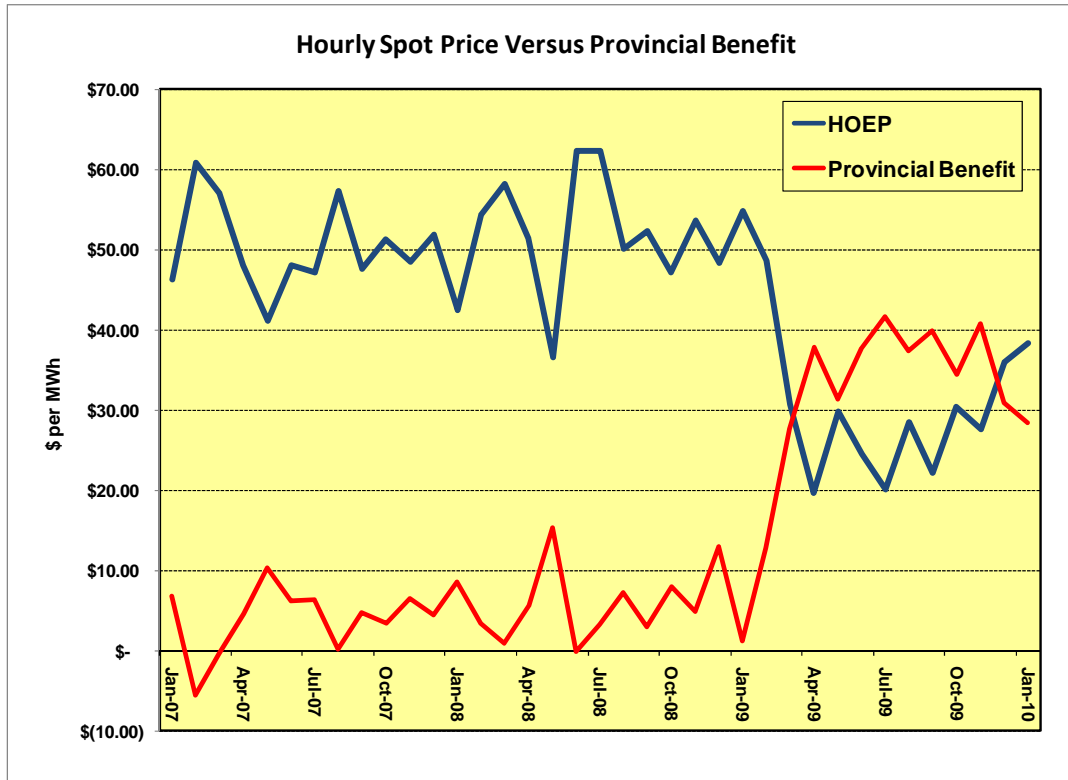
### **The Provincial Benefit**

Unlike most commodity markets, the Provincial government controls up to 70% of the electricity that is produced through its ownership of Ontario's largest generation company, Ontario Power Generation (OPG). The Provincial government has mandated that OPG must charge a fixed rate of \$52.15 per MWh (5.22¢/kWh) for electricity produced by OPG's largest generating facilities. Combined, these facilities produce almost 45% of the electricity consumed in the Province.

Of the remaining 50% of the electricity consumed in the Province, 25% has been secured by the OPA through a series of contracts that guarantee revenues to independent generators and participants in conservation programs. These contracts and programs are very lucrative and pay a per MWh price for electricity that is well above the nominal cost of electricity.

The capped-rate on OPG's largest generators and the cost of the OPA's contracts and programs above the nominal spot market cost of electricity are charged through to electricity consumers as a line item on their electricity invoices which is called the Provincial Benefit. It is imperative for Ontario electricity customers to

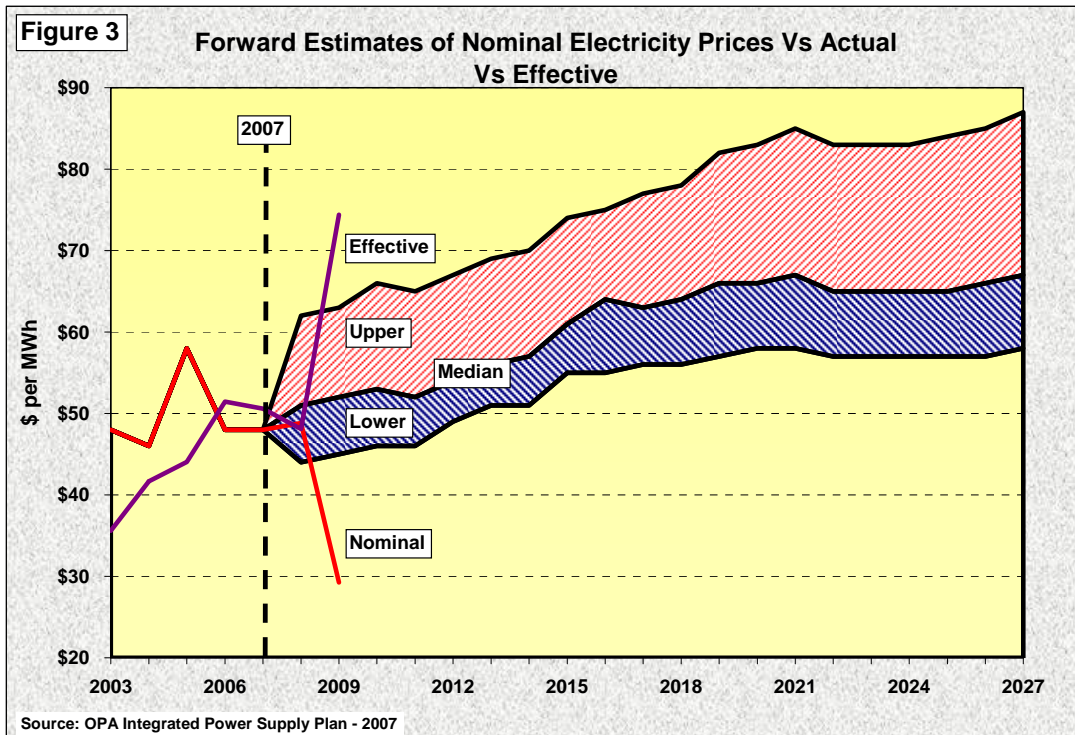
understand that the Provincial Benefit is a built in hedge because it is a derivative of the spot market price for electricity. This has two implications for electricity consumers. The first is that when the spot market price of electricity goes down, the Provincial Benefit goes up and vice-versa. This effect can be seen in the Graph below:



Adding to the impact that the Provincial Benefit has on current electricity consumers is the fact that the total funds collected remains constant because these are largely to pay for the fixed revenue contracts to merchant generators, however, the number of kWh consumed by the market can fluctuate greatly. In the current economy, a significant amount of demand has been destroyed by shuttered manufacturing. The remaining electricity consumers must pay a greater proportion of the Provincial Benefit to ensure the government can meet its contractual obligations. The second implication is that the Provincial Benefit is part of your spot market cost for electricity and not a separate line item on your invoice like fixed charges are. To calculate the effective cost of electricity use the following equation:

$$\text{Real Cost of Electricity} = \text{Spot Market Cost} + \text{Provincial Benefit}$$

**Figure 3** compares the IPSP price expectations with the nominal electricity price as well as the effective electricity price after the Provincial Benefit has been included:



It is common to ignore the Provincial Benefit when calculating your electricity commodity cost but it should be evident from the chart in **Figure 3** that doing so will paint a rosier financial picture than is actually the case and may lead you to make less than optimal decisions such as purchasing too much electricity as part of a forward hedge.

For the purposes of electricity procurement, the proportion (~50%) of electricity that is fixed and represented by the Provincial Benefit represents a government sponsored hedge on the spot market price of electricity. Under no circumstance does WattsWorth recommend that a municipal customer hedge more than 50% of its electricity consumption.

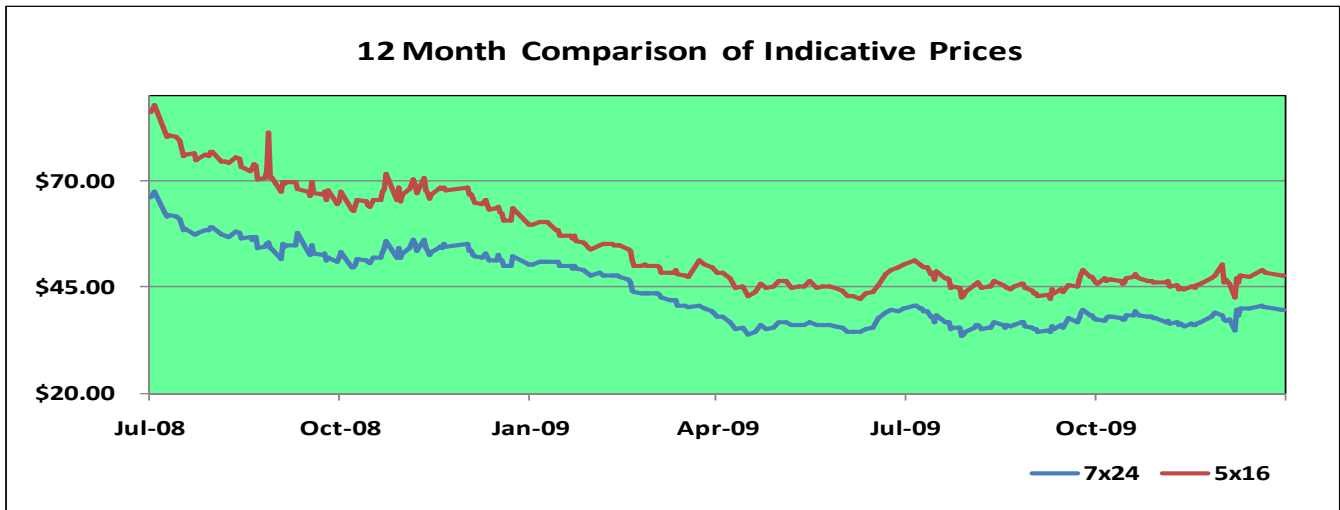
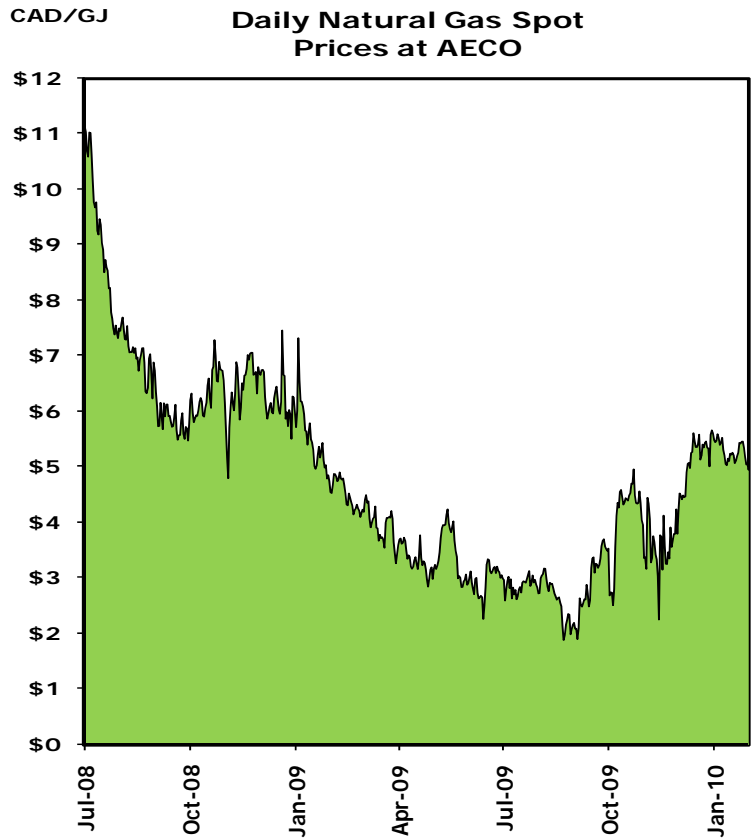
### Natural Gas and the Electricity Market

The price of natural gas plays a significant role in charting the cost of electricity in Ontario. The cost of natural gas impacts both the immediate spot market price for electricity as well as the price of future electricity contracts.

The horizon for using natural gas as a predictor of the future electricity spot market cost is only short-term. The decision to remain on the spot market because the electricity price is low will be an effective strategy only until either the price of natural gas or the demand for electricity increases. There will be little or no warning before the price of electricity increases and when the opportunity is gone, it's gone.

Comparatively, the value of future electricity contracts will remain for the term of the agreement. Forward electricity contracts are specifically determined by the underlying cost of natural gas at the time of the

contract. The current market price for natural gas has created a significant opportunity to extend this opportunity well into the future and beyond the short-term impact that natural gas prices are having on the spot market cost of electricity. The graph on the right shows the current trend in natural gas prices from July 2008 to January 2010. The corresponding impact on forward electricity contracts and its opportunity is evidenced in the forward electricity contract price chart below:



For the first time in the history of the electricity market the forward electricity contract price has a shallower slope than the forward curve of the electricity spot market. At the first hint of demand this situation will return to its normal state where forward contracts are at a premium to the spot market. Items that represent a constant danger to Ontario electricity consumers are the threat that:

- i. Nuclear reactors may fail unexpectedly and cannot be brought back on-line in the short-term;
- ii. Prolonged periods of hot weather in the summer months or cold in the winter months;
- iii. Events that impact the price of natural gas:
  - a. hurricane activity in the Gulf of Mexico
  - b. instability in the Middle East

These events will drive up the price of electricity and sustain them until the situation is resolved. Some items are very short-term in nature whereas others are longer. Municipalities that choose to utilize the spot market without a protective hedge must temper their market price expectations with the probability of those events occurring at any time during the year.

### **Market Summary**

As demand falls, the number of hours that cheaper forms of electricity generation (i.e. nuclear and hydro) can meet demand is increasing. Ontario's nominal cost of electricity is at a historical low but its effective cost is at an all time high because electricity consumers are charged the Provincial Benefit. Hedging is predominantly employed to mitigate risk but the current market risk for Ontario electricity consumers is the Provincial Benefit which cannot be hedged.

Until Ontario's demand increases sufficiently with the economy and without coal generation to incrementally step the price from nuclear and hydraulic to natural gas, the spot market cost is expected oscillate between high and low prices as needs change from hour-to-hour and natural gas generators are turned on and off. This increased volatility does not produce much price risk for spot market customers because the duration of the high prices is relatively low. As noted, electricity consumers can hedge the nominal cost of electricity but they cannot hedge the Provincial Benefit. For the foreseeable future Ontario faces greater downside risk than upside risk (locking into a contract that is well out of the money versus the risk that the spot market price will suddenly increase) Thus, hedging in the short-term which is defined by the period until such time as demand starts to strengthen is expected to be at a premium to the spot market cost of electricity but will provide little risk management benefits.

## Electricity Procurement Options - May 2010 to April 2011

### Option 1: Regulated Price Protection (RPP) Plan

The RPP is the government rate plan that municipal, residential, and small commercial accounts default into if an alternative procurement plan is not chosen. The intention of this plan is to have two tiers of electricity rates; one that is below the cost of electricity which recognizes that electricity is an essential service, and a second one set above the cost of electricity to provide incentive for consumers to conserve electricity. The threshold between the first and second-tier rates is 750 kWh, the amount that an average residential home uses. The detriment for municipal customers is that a large number of their electricity accounts exceed the threshold of 750 kWh very early in the month. Thus, the effective cost of electricity is always higher than the spot market cost for electricity.

Rates for the RPP are primarily based on the expected future cost of electricity. As required, the rates are adjusted to ensure a balance between the proceeds from electricity consumers and the actual cost of electricity.

A summary of the RPP rates are as follows:

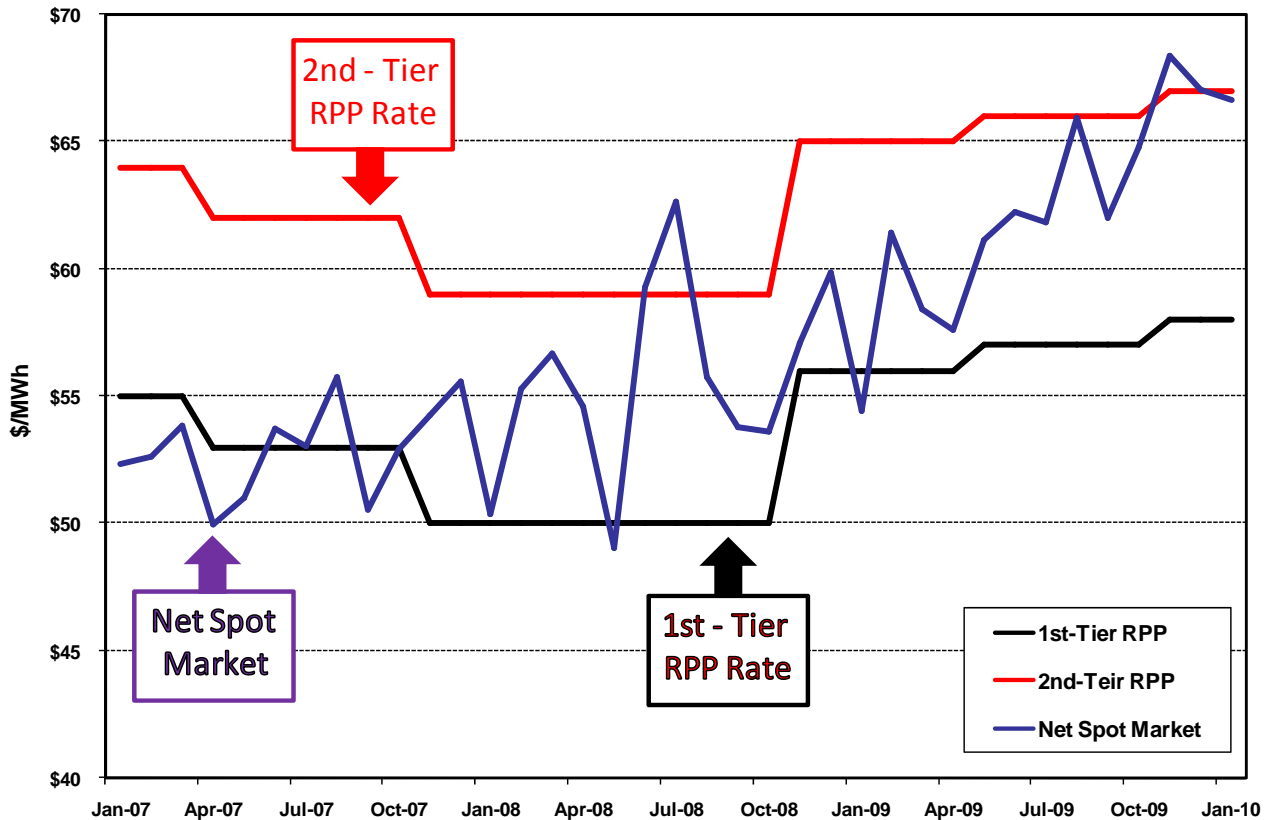
<b>Term</b>	<b>Rate</b> ( < 750 kWh, >750 kWh)	<b>% Change</b>
<b>Jan 1, 04 to Apr 30, 06</b>	<b>5.0¢ / 5.8¢</b>	
<b>May 1, 06 to Oct 31, 06</b>	<b>5.8¢ / 6.7¢</b>	<b>+ 15.5%</b>
<b>Nov 1, 06 to Mar 31, 07</b>	<b>5.5¢ / 6.4¢</b>	<b>- 4.5%</b>
<b>Apr 1, 07 to Oct 31, 07</b>	<b>5.3¢ / 6.2¢</b>	<b>- 3.1%</b>
<b>Nov 1, 07 to Oct 31, 08</b>	<b>5.0¢ / 5.9¢</b>	<b>- 4.8%</b>
<b>Nov 1, 08 to Apr 30, 09</b>	<b>5.6¢ / 6.5¢</b>	<b>+ 10.2%</b>
<b>May 1, 09 to Oct 31, 09</b>	<b>5.7¢ / 6.6¢</b>	<b>+ 1.5%</b>
<b>Nov 1, 09 to Present</b>	<b>5.8¢ / 6.7¢</b>	<b>+ 1.5%</b>

The graph below charts the month over month cost of electricity utilizing the first and second-tier RPP rate as well as the effective cost of electricity. As is evident, the first-tier rate is the most attractive procurement option. Electricity customers that consume more than the 750 kWh thresholds each month are better off utilizing the spot market as the conservation incentives that are built into the second-tier RPP rates are cost prohibitive<sup>1</sup>.

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<sup>1</sup> Most electricity accounts require a hedge in order to mitigate the volatility of the spot market while still returning savings over the RPP rate. The cost of billing to facilitate the move out of the RPP is not factored into the Net Spot Market cost of electricity

Comparison RPP Tiered Rates to Net Spot Market



**The RPP After October 31, 2009**

As of November 1, 2009, Municipal electricity customers will no longer default into the RPP as their means of electricity procurement. Only Municipal electricity accounts that fall within the Designated Customer Class (< 250,000 kWh per year or < 50 kW in demand) will still qualify for the RPP.

**Option 2: Spot Market Without Hedging**

The rate paid for electricity is determined by the hourly spot market cost of electricity (commonly known as HOEP or Hourly Ontario Electricity Price) and each hour’s corresponding consumption. With the risk management provided by government programs, the spot market has proven to be the cheapest procurement option over the long-term (5 years or more). Within any individual year the spot market can be a more expensive option than the RPP as we have seen in 2005. With the changes in the electricity market that occurred on May 1, 2009 (end of OPG Rebate), the greater market exposure to the full volatility of the spot market price will mean greater risk.

**Option 3: Spot Market With a Hedge**

An electricity hedge is a financial contract between a customer and a supplier that effectively exchanges the customer’s volatile spot market cost of electricity with the supplier’s fixed cost of electricity for a defined volume or “block” of electricity. If designed and executed properly (net of the Provincial Benefit proportion) a financial

contract acts like an insurance policy that guarantees cost and offsets risk. Like an insurance policy there is a premium to be paid to offset this risk. The premium charged in the current forward contract market is very low which represents real value to budget and cost conscious managers.

### **Hedge Options (7x24 contract Vs 5x16 contract)**

Forward contracts are available in many different forms each with their own benefits. The two options available to municipalities are the 7x24 forward contracts and/or the 5x16 forward contracts. A 7x24 contract is designed to manage risk 7 days a week and 24 hours a day. A 5x16 contract is designed to manage risk 5 days a week (Monday to Friday excluding holidays) and 16 hours per day (8 a.m. to 11 p.m.). The benefit of a 7x24 contract is the maximal coverage that it offers and its overall lower price (see Indicative Forward Contract Chart above). The benefit of a 5x16 contract is that it specifically applies risk management to the period of the day where the customer is actually at risk.

- (1) Based on WattsWorth's analysis, Municipal electricity consumption peaks when the spot market price is its most volatile (7a.m. to 11 p.m., Monday to Friday). It is also apparent from the consumption profile that the Municipality's consumption falls on weekends and holidays. A 7x24 contract will result in an obligation to purchase electricity that the Municipality is not consuming. A 5x16 contract would better your Municipality's pattern of consumption.
- (2) Although the contract price of a 7x24 is lower than that of a 5x16, its value is determined by the underlying spot market price for electricity. A 5x16 contract is swapped against the most volatile and expensive period of day whereas a 7x24 contract is swapped against all hours of the day, including those that are low risk and low price which account for 50% of all hours in the year. During the on-peak, market prices in Ontario are 7.8 times more volatile than the off-peak market. The result is that the underlying market price that gives the 5x16 contract its value will more than compensate for the premium paid for this contract as compared to the 7x24 contract. A good analogy would be to compare the price of lead to that of gold. Gold will cost more than lead but because of the market value of gold, it is worth more. WattsWorth's analysis of past and future markets indicates that a premium of \$21 per MW per hour for a 5x16 contract over the 7x24 contract is the point at which both contract types have equal value. At present the price differential between a 7x24 and 5x16 contracts is only \$13 per MW per hour, making the 5x16 contract more valuable.

### **Option 4: Retail Supply Contract**

Much the same as the RPP program, municipalities can enter a fixed rate contract with a retailer that covers all of their consumption with a single price. The term (usually 5 years) and the price are both set at the beginning of the contract. Most retail contracts allow for the customer to retain the rebates which, in some ways, offsets the premium that these contracts charge. Current retail contracts require a five year commitment and offer a fixed

price of 8.99¢ per kWh, well above the cost of the RPP. Given the size and sophistication of municipal customers, a retail contract would not provide any benefits over the RPP.

### **Option 5: Time-of-Use Rates**

The Time of Use (TOU) program is a government back rate mechanism that sets different rates for electricity purchased at different time of the day. Current TOU rates recognize three distinct time zones, Off-Peak, Mid-Peak, and On-Peak. Prices range from 4.4¢ per kWh for the Off-Peak, 7.9¢ per kWh for the Mid-Peak, and 9.9¢ per kWh for the On-Peak. The program is designed to provide incentives for program users to move their consumption of electricity from the On-Peak to the Mid or Off-Peak in order to save money.

WattsWorth cautions its customers that TOU rates may actually cost them more than the current RPP programs because the highest rate takes effect when municipalities generally consume the majority of their electricity; during the on-peak.



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and Options Summary**

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## WattsWorth Electricity Procurement Strategy

The Town of Ingersoll (Ingersoll) manages 56 electricity accounts which fall into one of the following electricity account types based on how they are metered: NSLS (non-interval), interval, and street lights. From this list, WattsWorth has created five pools of accounts: small NSLS (non-interval), large NSLS (non-interval), interval peaking, interval non-peaking, and street lights. Combined, these accounts consume almost 5-million kWh annually. Procurement options for these various account pools are as follows:

- Option 1: The Regulated Price Protection (RPP) Plan – **(small NSLS only)**
- Option 2: The Spot Market without Hedging
- Option 3: The Spot Market with Hedging
- Option 4: Retail Contracting
- Option 5: Time-of-Use (TOU) – **(not currently available from your local utilities)**

Because the consumption pattern and needs of each account differ significantly, WattsWorth’s overall strategy is in fact a suite of different strategies that best meets the needs of each individual account. WattsWorth’s analysis of procurement options for the Large NSLS, Interval Peaking, Interval Non-Peaking, and Street Light accounts will not include the RPP, Retail Contracting, or Time-Of-Use options since the municipality is either ineligible or the program is outright too expensive. The decision for the Town is then whether or not to hedge and if to hedge, then what form and proportion should the hedge take. Four options proven to be optimal for municipal customers are available for hedging and are categorized as the following:

Description	7x24 Proportion	5x16 Proportion	Proportion of On-Peak Coverage	Comment
Hedge “A”	10% to 20%	20% to 30%	85%	Majority of all electricity consumed is fixed with a hedge or Capped Rate Mechanism
Hedge “B”	0%	35%	85%	Take advantage of low Off-Peak prices but hedge majority of On-Peak consumption
Hedge “C”	0%	25%	75%	Take advantage of low Off-Peak prices but hedge some of the On-Peak consumption
Hedge “D”	0%	15%	65%	Take advantage of low Off-Peak prices but hedge the minimum of the On-Peak consumption

As part of the 2009 strategy, WattsWorth recommended that your municipality purchase a proportion of your 2010 electricity needs (May 2010 to April 2011) at the same time as your 2009 purchase. This contract is represented in the strategy as the "Base" option. For each account pool, WattsWorth has provided an analysis of the most likely financial results utilizing the spot market as well as each of the potential hedges above. The Town will need to review each carefully and choose the one that best meets its need to balance savings and risk management.

## Strategy Analysis

### Small Net System Load Shape Accounts

These accounts still qualify for the RPP due to their small demand (<50 kW) and low annual consumption (<250,000 kWh). WattsWorth has chosen this option for the smallest accounts because the majority of their electricity is charged at the first-tier RPP rate. History has shown that the first-tier RPP rates are generally at or below the spot market rates and very stable. First-tier rates are traditionally very attractive because they are geared toward residential customers; more specifically, voters. These low rates are generally at the expense of larger RPP accounts. The threshold between small and large NSLS pool designation for the purpose of this strategy is consumption of approximately 16,000 kWh annually. Below this consumption the account should remain in the RPP; above it, the account should be moved out of the RPP. The lists of accounts in each pool are provided in Appendix D.

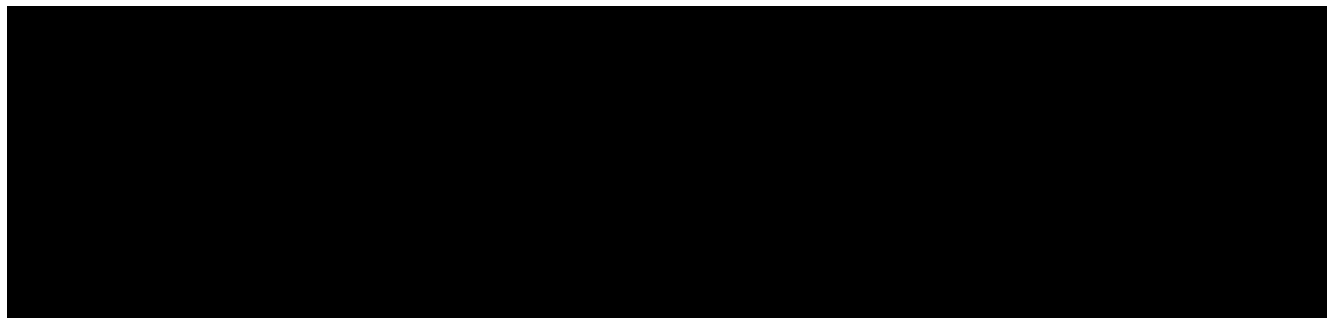
### Large Net System Load Shape

The Town's Large Net System Load Shape (NSLS or non-interval) accounts consume almost 800,000 kWh annually. After November 1, 2009 the default procurement option for accounts that consume more than 250,000 kWh annually has become the spot market. The summary and comparison of financial outcomes under each procurement option is as follows:

**Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:**

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Hedge "A"										
Hedge "B"	\$ 55.41	\$ 60.30	\$ 67.59	\$ 70.92	\$ 72.64	\$ 39,662	\$ 45,050	\$ 52,876	\$ 60,474	\$ 63,081
Hedge "C"										
Hedge "D"										
Base	\$ 52.15	\$ 57.04	\$ 67.21	\$ 71.83	\$ 73.54	\$ 34,272	\$ 39,269	\$ 52,579	\$ 63,102	\$ 65,759
RPP 2010	\$ 73.56	\$ 73.59	\$ 73.62	\$ 73.63	\$ 73.64	\$ 51,213	\$ 53,539	\$ 57,592	\$ 62,784	\$ 63,946
Actual 2009			\$ 61.93					\$ 47,340		

## Hedges:

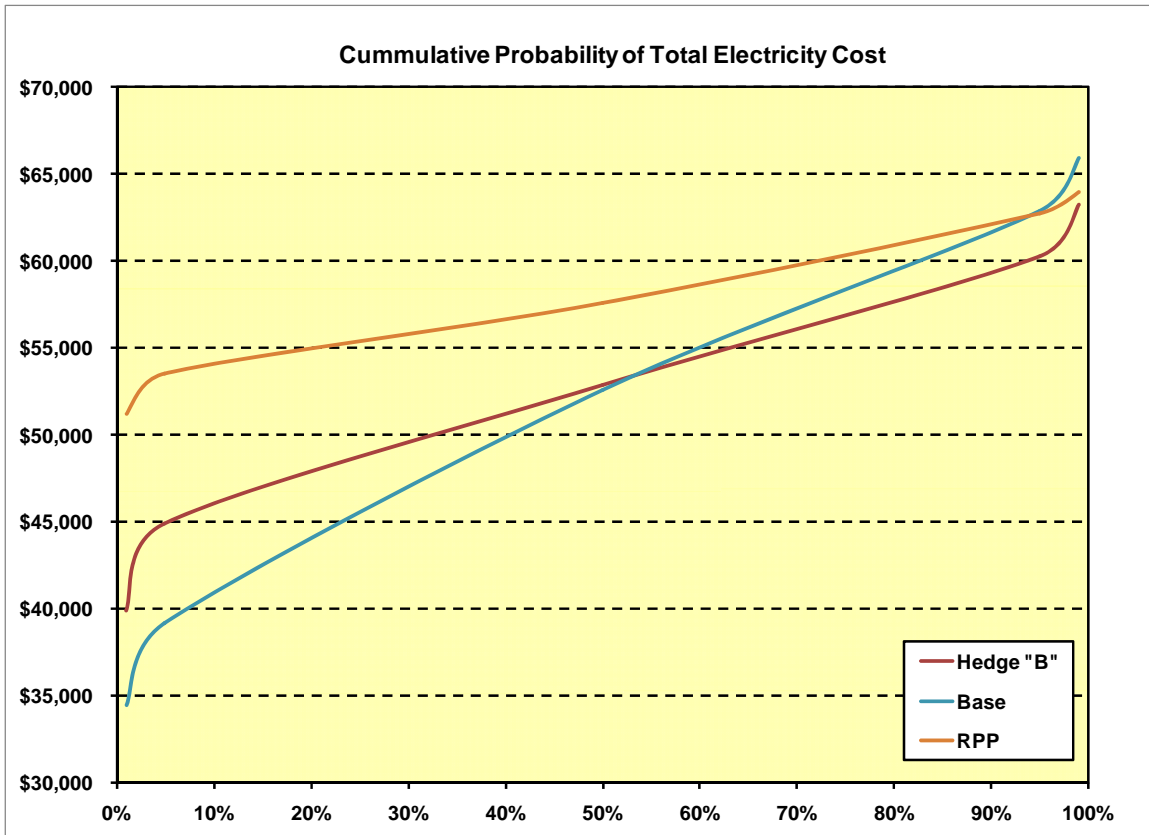


Because the Town purchased the volume for Hedge C as part of its 2009 strategy, incremental volumes of C and D are not required to achieve the proportion of contracted consumption. Because Hedge A requires a smaller proportion of the block actually purchased in the off-peak, the Town is precluded from utilizing Hedge A because it would then be speculating. In the current market Hedge A would be the least optimal option and would not be recommended by WattsWorth as a strategy the Town should consider to meet its needs in 2010-11.

The graph below compares the net commodity cost<sup>1</sup> of each of the above hedges and the spot market under various market conditions. For comparison purposes the cost of electricity using the effective RPP rates in 2010 (5.8/6.7¢ /kWh) as well as the actual strategy cost of electricity in previous years have also been included. Using the cumulative probability detailed on the X-axis, you can determine the probability of paying more or less using the various strategy options. The spot market provides the greatest opportunity for savings when the market price is low but has the greatest risk when the market price is high. Regardless of the procurement option, the Region has a 95% chance of breaking even with its cost of electricity using the RPP. This is evidenced by the intersection of the strategies with the RPP cost line which is just above the 95%-ile.

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<sup>1</sup> The Commodity Cost for electricity customers is the cost of electricity from the spot market and the Provincial Benefit true-up mechanism. This does not include fixed costs for Transmission, Distribution and Delivery. Allowances must be made for these for the purposes of budgeting total electricity costs.



**Recommendation:**

The resultant analysis provides a strong incentive for the Town to utilize the Base option for its electricity procurement until such time as the economy begins to show strength, electricity demand returns, and with it, risk. There are enough price management tools built into the spot market price of electricity and the existing 2010 contract purchased as part of the 2009 strategy that the Town faces little risk at the present time.

**Interval Accounts**

The Town's Interval accounts consume almost 2-million kWh annually. The effective spot market charge for interval accounts is based specifically on the usage profile of the account. In order to apply the proper strategy for each account, it is important to examine the proportion of the consumption that is fully exposed to spot market volatility. The resulting output is as follows:

**Ratio of On-Peak Consumption to Off-Peak**

Account #	Description	Off Peak	On Peak					Account Pool
			Winter	Spring	Summer	Fall	Annual	
00100549-00	Library	1:	1.710	1.967	2.133	1.795	1.922	Peaking
00161052-00	Youth Centre	1:	1.783	1.768	2.038	1.954	1.871	Peaking
00100499-04	Pool	1:	1.499	1.536	1.662	1.502	1.547	Peaking
00100580-03	Arena	1:	1.430	1.471	1.512	1.401	1.437	LSC
00100606-01	Public Works	1:	1.520	1.474	1.437	1.504	1.484	Non-Peaking

Each interval account has been classified into one of three categories based on its On-Peak ratio and consumption behaviour. The three categories are Peaking, Non-Peaking, and Low-Summer Consumption (LSC). Non-Peaking and LSC accounts consume electricity in such a manner that their market risk is very low. If the price of electricity trends upward, it will likely do so when the account is not using a lot of electricity and thus its overall cost of electricity will remain low. For these accounts a hedge will provide little risk mitigation and thus little value for the cost premium the Town would pay. Peaking accounts tend to consume the majority of their electricity when the spot market price is most likely to rise due to underlying market impacts. When it does the increase in electricity price is directly felt on the invoice. These accounts benefit from a properly designed hedge to balance risk with savings. The point at which an account is classified as Peaking or Non-Peaking is 1:1.5. At 1:1.5, approximately 25% of a market price shock will end up on your electricity invoice. Greater ratios result in a greater proportion of the market risk translating into invoice cost.

### Interval – Peaking Accounts:

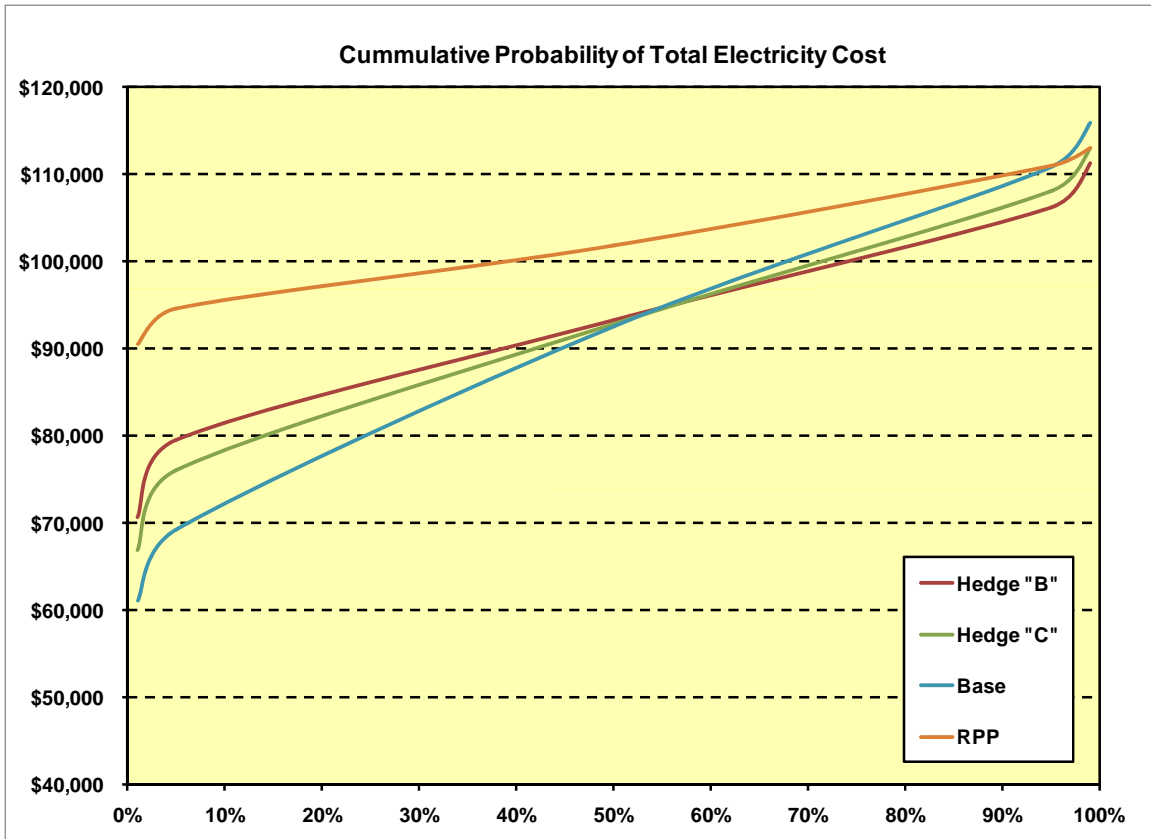
Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Hedge "A"										
Hedge "B"	\$ 56.70	\$ 61.35	\$ 68.51	\$ 71.54	\$ 73.37	\$ 70,618	\$ 79,747	\$ 93,251	\$ 106,149	\$ 110,860
Hedge "C"	\$ 54.59	\$ 60.24	\$ 68.22	\$ 72.10	\$ 73.92	\$ 66,873	\$ 76,263	\$ 92,855	\$ 107,958	\$ 112,696
Hedge "D"										
Base	\$ 53.36	\$ 58.00	\$ 68.07	\$ 72.41	\$ 74.23	\$ 61,008	\$ 69,474	\$ 92,657	\$ 110,688	\$ 115,486
RPP 2010	\$ 74.74	\$ 74.77	\$ 74.80	\$ 74.81	\$ 74.82	\$ 90,542	\$ 94,654	\$ 101,819	\$ 110,997	\$ 113,052
Actual 2009			\$ 61.70					\$ 81,881		

### Hedges:

Details		7x24		5x16		Term	Proportion of Consumption	
		Size	Rate	Size	Rate		Total	On-Peak
2009 Strategy:	Year 1:	--	--	0.045 MW	\$52.50 /MW	May 2009 to April 2010	0%	0%
	Year 2:	--	--	0.045 MW	\$63.73 /MW	May 2010 to April 2011	54%	71%
2010 Strategy (incremental to 2009 strategy contract for 2010)	Hedge A:							
	Hedge B:	--	--	0.03 MW	\$55.00 /MW	May 2010 to April 2011	54%	85%
	Hedge C:	--	--	0.01 MW	\$55.00 /MW	May 2010 to April 2011	54%	75%
	Hedge D:							

The graphed comparisons of net commodity costs using each scenario are provided below.



**Recommendation:**

The above graph highlights the risk for the peaking interval accounts under each procurement strategy. As is evident the current market conditions combined with the existing contract for 2010 do not present the Town with a significant amount of risk that would warrant an additional contract purchase. WattsWorth recommends the Town stay with the Base option.

**Interval – Non-Peaking and Low Summer Consumption (LSC) Accounts:**

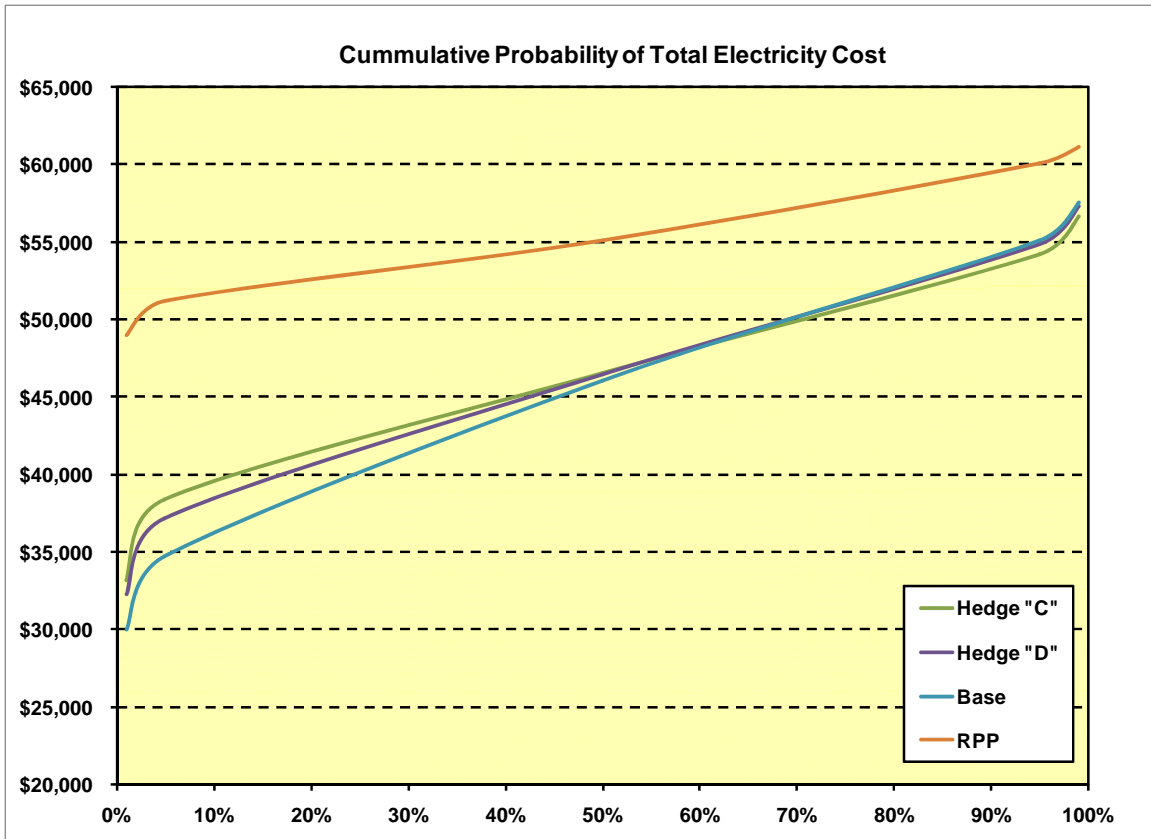
**Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:**

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Hedge "A"										
Hedge "B"										
Hedge "C"	\$ 50.70	\$ 56.04	\$ 63.38	\$ 67.35	\$ 68.66	\$ 33,534	\$ 38,306	\$ 46,584	\$ 54,447	\$ 56,517
Hedge "D"	\$ 49.85	\$ 54.85	\$ 63.25	\$ 67.56	\$ 68.87	\$ 32,608	\$ 37,091	\$ 46,485	\$ 55,114	\$ 57,194
Base	\$ 49.13	\$ 53.50	\$ 62.71	\$ 67.06	\$ 68.35	\$ 30,332	\$ 34,601	\$ 46,089	\$ 55,347	\$ 57,423
RPP 2010	\$ 74.94	\$ 74.97	\$ 75.00	\$ 75.01	\$ 75.02	\$ 49,018	\$ 51,244	\$ 55,123	\$ 60,092	\$ 61,204
Actual 2009			\$ 58.89					\$ 42,299		

**Hedges**

Details		7x24		5x16		Term	Proportion of Consumption	
		Size	Rate	Size	Rate		Total	On-Peak
2009 Strategy:	Year 1:	--	--	0 MW	\$52.50 /MW	May 2009 to April 2010	53%	51%
	Year 2:	--	--	0 MW	\$63.73 /MW	May 2010 to April 2011	53%	51%
2010 Strategy	Hedge A:							
	Hedge B:							
(incremental to 2009 strategy contract for 2010)	Hedge C:	--	--	0.025 MW	\$55.00 /MW	May 2010 to April 2011	53%	75%
	Hedge D:	--	--	0.02 MW	\$55.00 /MW	May 2010 to April 2011	53%	65%

The graphed comparisons of net commodity costs using each scenario are provided below.



**Recommendation:**

Even at extreme market results the hedge’s results are not much better than the pure spot market. At the same time, the premium paid for the hedge requires the Town to forego some of its benefit when the market price is low. It is WattsWorth’s recommendation that these accounts remain on the spot market and utilize their “built in” hedge to manage their risk.

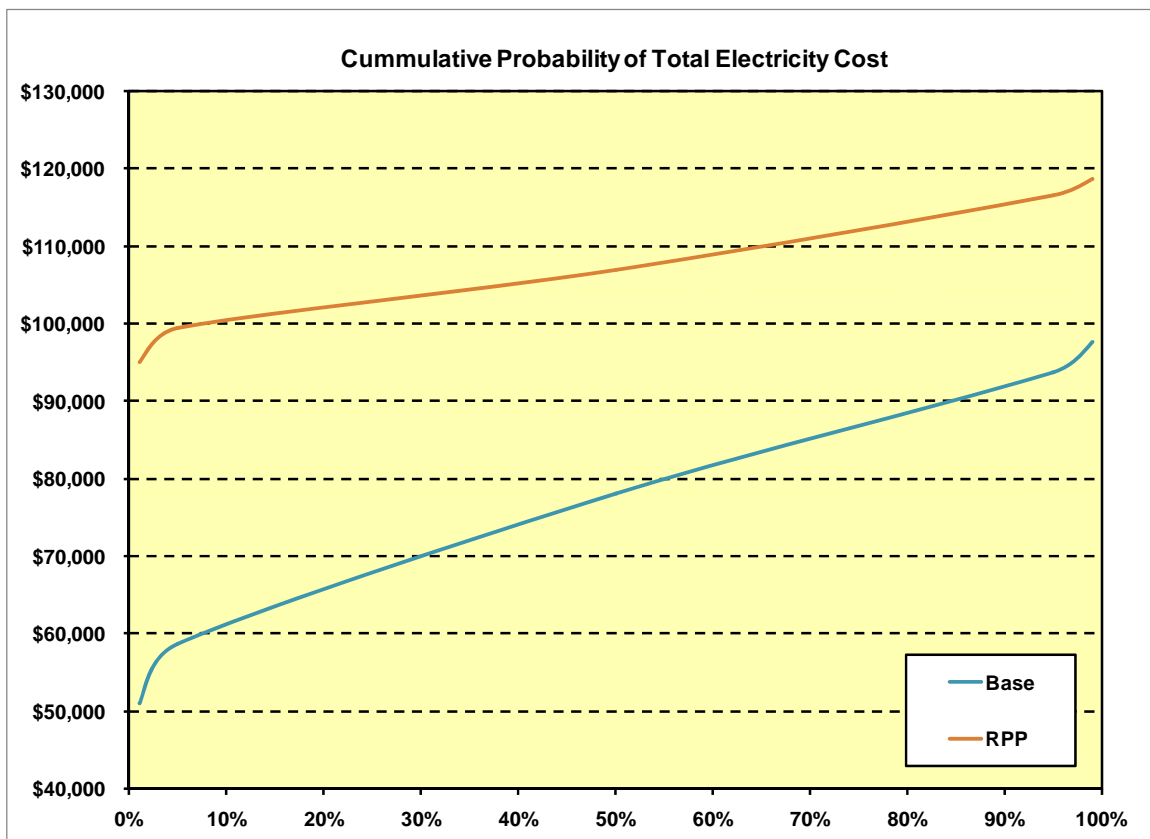
**Street Light Account**

The Town’s street light account consumes approximately 1.5-million kWh annually. Street lights are self-hedging because they operate almost exclusively at a time when the spot market prices are at their minimums. Adverse prices that may occur are generally short in duration and are more than offset by the longer-term low prices. A comparison of the financial outcome under each procurement option is as follows:

**Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:**

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Base	\$ 42.76	\$ 46.66	\$ 54.72	\$ 58.03	\$ 59.74	\$ 51,265	\$ 58,598	\$ 78,090	\$ 93,011	\$ 97,453
RPP 2010	\$ 74.87	\$ 74.91	\$ 74.94	\$ 74.95	\$ 74.96	\$ 95,105	\$ 99,423	\$ 106,949	\$ 116,590	\$ 118,748
Actual 2009			\$ 54.09					\$ 75,342		

As is evident from the analysis, the cumulative probability of saving over the RPP is 95%. For this reason, a hedge is not recommended as it will provide the Town with no risk management benefits.



## Strategy Recommendation

Following WattsWorth's recommendation, the Town of Ingersoll purchased a contract for May 1, 2010 to April 30, 2011 as part of its 2009 contract requirements. Given the unprecedented nature of the global economy and its impact on the Ontario electricity market, the contract quantity purchased in 2009 for the coming strategy term will be sufficient to manage the Town's electricity procurement requirements until the next strategy term.

WattsWorth's focus will be to ensure that the Town's electricity accounts are seamlessly transitioned from Shell Trading (current supplier) to Direct Energy (winner of second term award).

### Summary

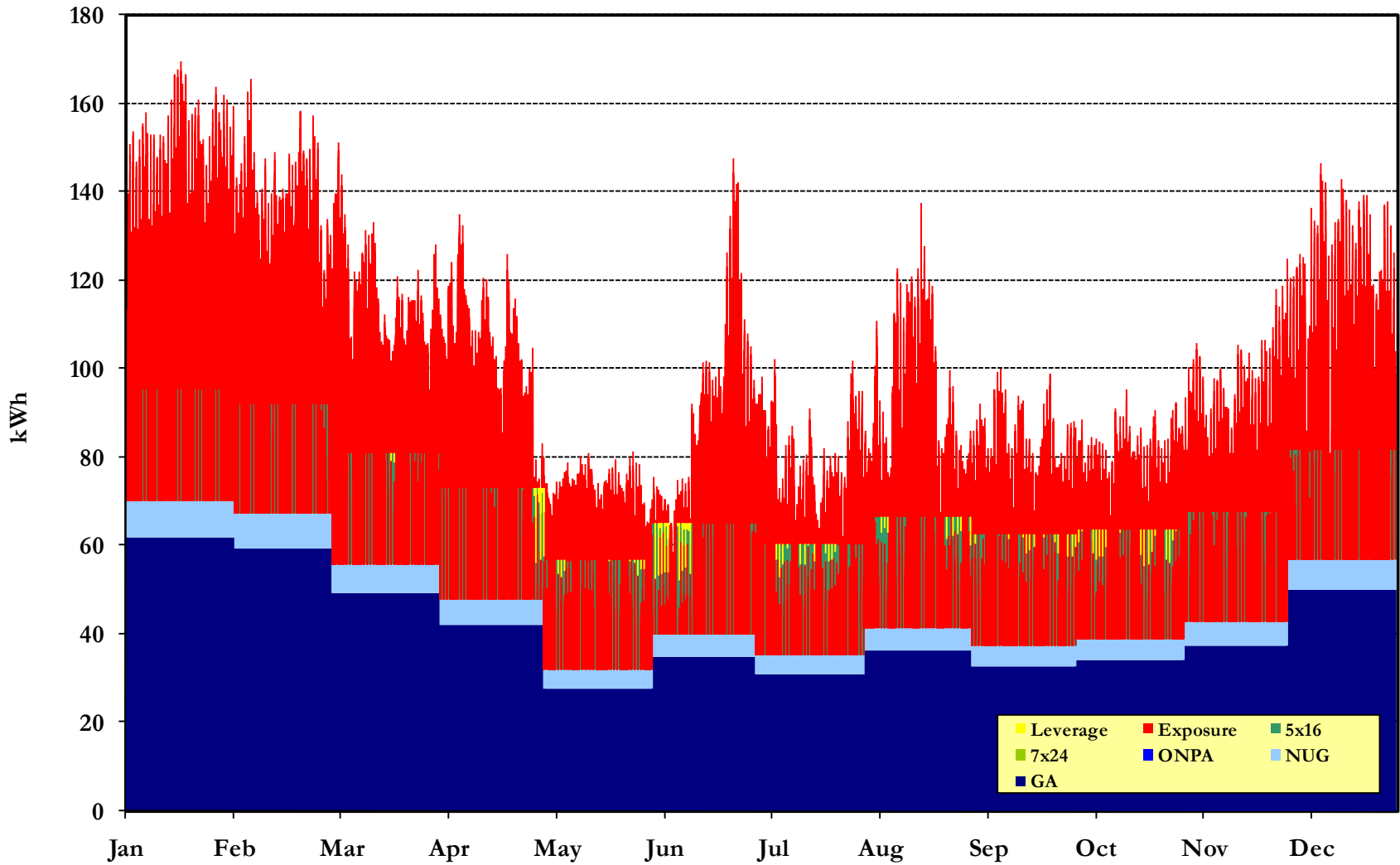
**Table of Expected Financial Outcomes and their Cumulative Probability of Occurrence:**

Procurement Option	Per kWh Unit Cost					Per kWh Unit Cost				
	Min	5%	Avg	95%	Max	Min	5%	Avg	95%	Max
	(\$/MWh)					Total Commodity \$				
Hedge "A"										
Hedge "B"	\$ 50.82	\$ 55.38	\$ 62.89	\$ 66.24	\$ 67.92	\$ 195,079	\$ 221,701	\$ 270,801	\$ 314,081	\$ 327,911
Hedge "C"	\$ 49.56	\$ 54.44	\$ 62.73	\$ 66.58	\$ 68.25	\$ 185,944	\$ 212,435	\$ 270,108	\$ 318,517	\$ 332,425
Hedge "D"	\$ 49.03	\$ 53.53	\$ 62.66	\$ 66.71	\$ 68.39	\$ 179,152	\$ 204,432	\$ 269,811	\$ 321,915	\$ 335,892
Base	\$ 48.90	\$ 53.30	\$ 62.57	\$ 66.62	\$ 68.30	\$ 176,876	\$ 201,942	\$ 269,416	\$ 322,147	\$ 336,121
RPP 2010	\$ 74.60	\$ 74.64	\$ 74.67	\$ 74.68	\$ 74.69	\$ 285,879	\$ 298,859	\$ 321,483	\$ 350,464	\$ 356,951
Actual 2009			\$ 58.74					\$ 246,862		

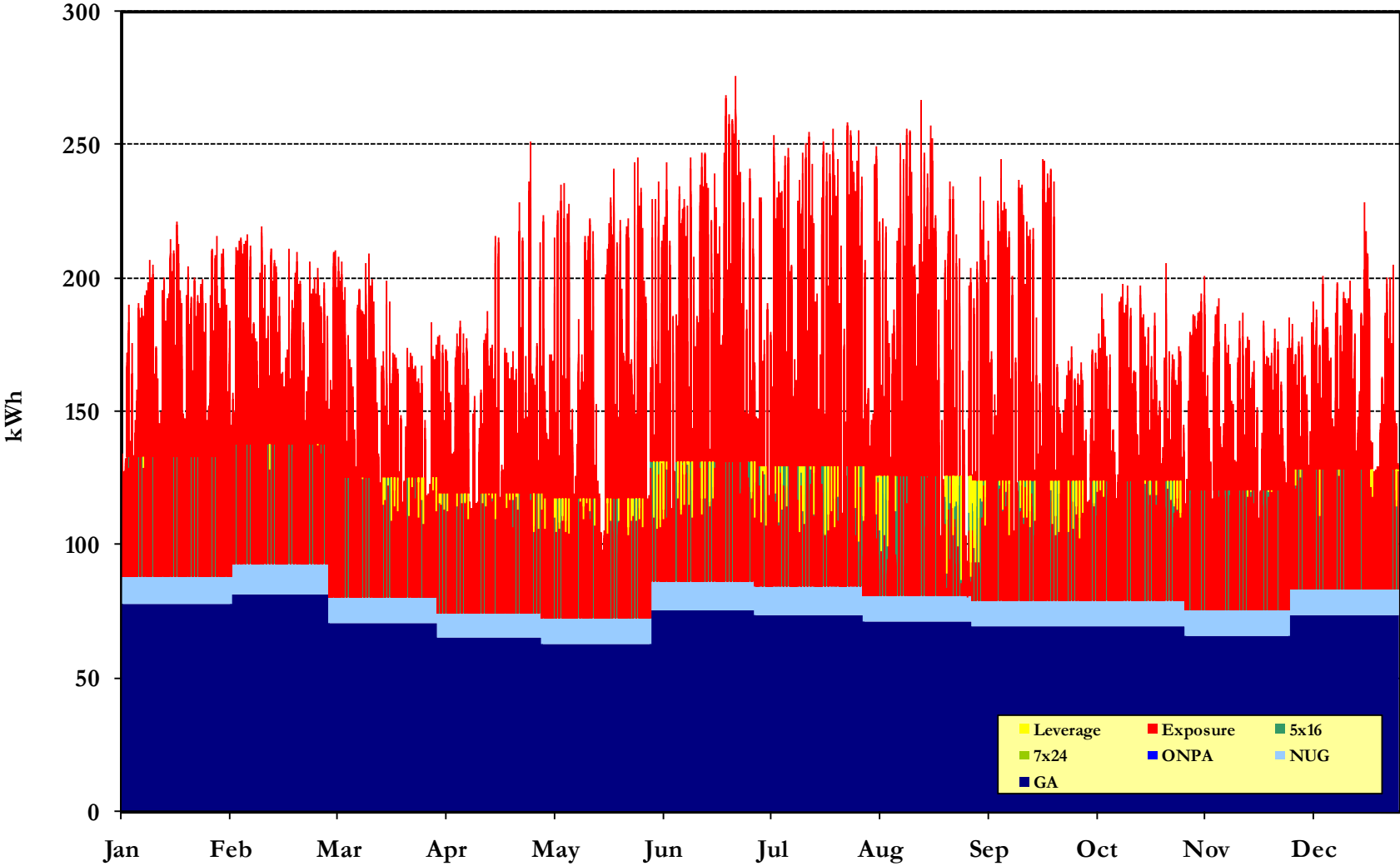
Utilizing WattsWorth's recommendation for all accounts that consume more than 16,000 kWh per year the Town's unit cost of electricity is expected to be \$62.57 per MWh for electricity consumed in 2010-11. The total commodity cost for this strategy is expected to be approximately \$270,000. As explained in the Market Outlook report, the market risk for Ontario electricity consumers over the next 18-months is very low and will remain so until the manufacturing economy rebounds. Combined with the Town's current contract for 2010-2011, the need for an additional contract purchase is non-existent. Throughout the year WattsWorth will be monitoring the market conditions and, if need be, we will propose changes to meet your changed needs.

# Appendix A: Overlay of Hedge D Strategy with Consumption

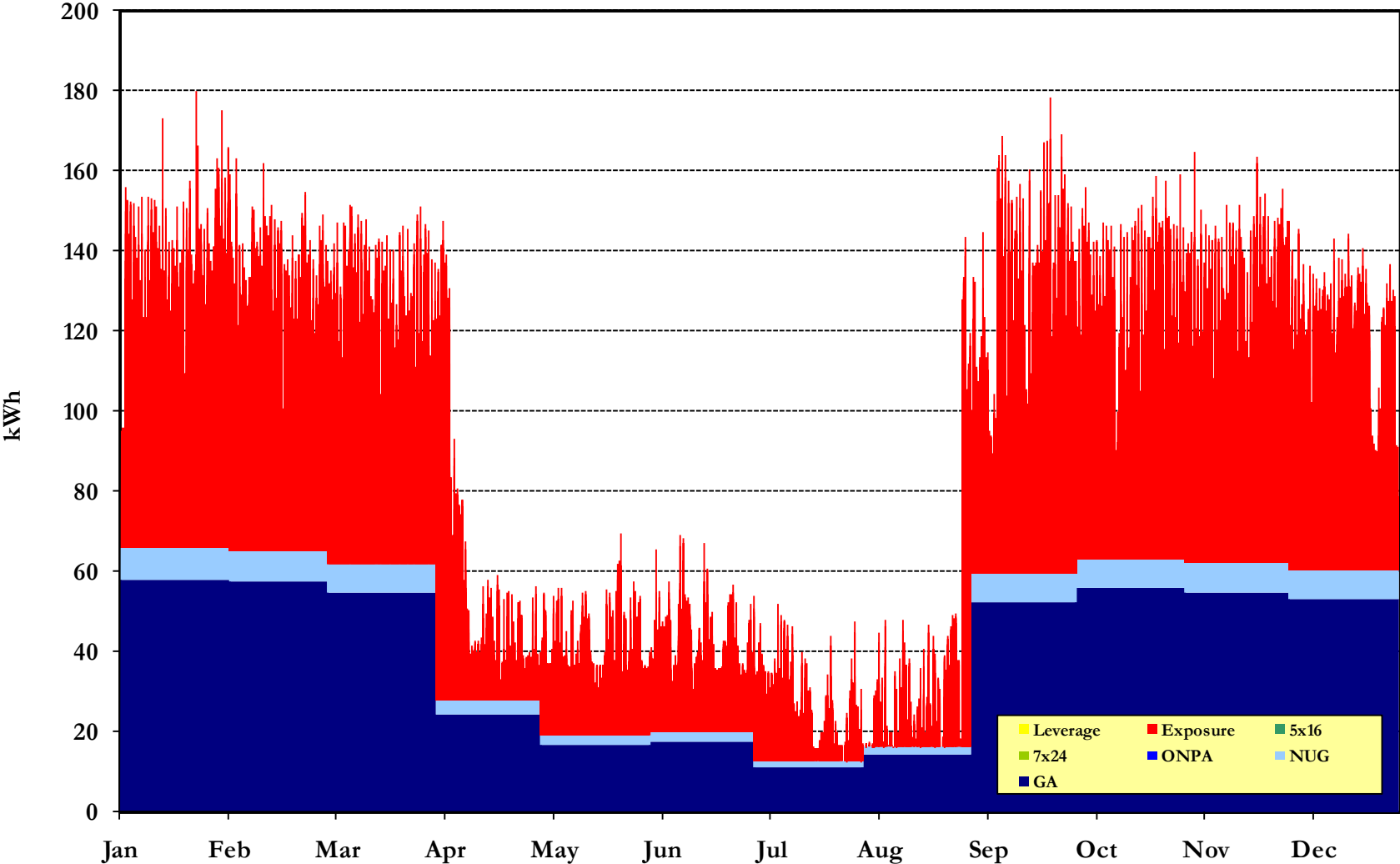
## Ingersoll - Large Non-Interval Accounts Strategy Profile - Annual



Ingersoll - Peaking Interval Accounts  
Strategy Profile - Annual



Ingersoll - Non-Peaking Interval Accounts  
Strategy Profile - Annual



## Appendix B: Commodity Results Budget by Strategy

### Town of Ingersoll Proposed Annual Commodity Budget by Option

Mean Model Results	Balance of 2009 Strategy				2010 Strategy								2010 Annual Budget
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	
kWh	456,308	396,747	395,397	312,209	279,174	289,423	284,466	325,854	380,579	378,736	384,068	422,681	4,305,641
Cost at Spot:	\$ 17,134	\$ 14,047	\$ 13,242	\$ 7,178	\$ 7,525	\$ 10,317	\$ 13,582	\$ 16,141	\$ 17,598	\$ 15,679	\$ 15,250	\$ 19,140	\$ 166,833
Prov. Benefit:	\$ 12,320	\$ 12,025	\$ 12,423	\$ 10,297	\$ 9,939	\$ 7,878	\$ 6,938	\$ 4,180	\$ 5,303	\$ 5,316	\$ 8,981	\$ 12,455	\$ 108,056
2009 Strategy:	\$ 209	\$ 180	\$ 232	\$ 273	\$ 595	\$ 322	\$ 157	\$ 39	\$ 138	\$ 309	\$ 329	\$ 319	\$ 3,102
Base Market Cost:	\$ 29,663	\$ 26,252	\$ 25,898	\$ 17,748	\$ 18,058	\$ 18,516	\$ 20,677	\$ 20,360	\$ 23,039	\$ 21,305	\$ 24,560	\$ 31,915	\$ 277,990
per Unit Cost:	\$ 65.01	\$ 66.17	\$ 65.50	\$ 56.85	\$ 64.68	\$ 63.98	\$ 72.69	\$ 62.48	\$ 60.54	\$ 56.25	\$ 63.95	\$ 75.51	\$ 64.56
<b>Hedge "A" Result</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Cost Net of Hedge:	\$ 29,663	\$ 26,252	\$ 25,898	\$ 17,748	\$ 18,058	\$ 18,516	\$ 20,677	\$ 20,360	\$ 23,039	\$ 21,305	\$ 24,560	\$ 31,915	\$ 277,990
per Unit Cost:	\$ 65.01	\$ 66.17	\$ 65.50	\$ 56.85	\$ 64.68	\$ 63.98	\$ 72.69	\$ 62.48	\$ 60.54	\$ 56.25	\$ 63.95	\$ 75.51	\$ 64.56
<b>Hedge "B" Result</b>	\$ -	\$ -	\$ -	\$ -	\$ 257	\$ 68	\$ (37)	\$ (100)	\$ (43)	\$ 67	\$ 86	\$ 73	\$ 370
Cost Net of Hedge:	\$ 29,663	\$ 26,252	\$ 25,898	\$ 17,748	\$ 18,315	\$ 18,585	\$ 20,640	\$ 20,260	\$ 22,996	\$ 21,372	\$ 24,645	\$ 31,988	\$ 278,360
per Unit Cost:	\$ 65.01	\$ 66.17	\$ 65.50	\$ 56.85	\$ 65.60	\$ 64.21	\$ 72.56	\$ 62.17	\$ 60.42	\$ 56.43	\$ 64.17	\$ 75.68	\$ 64.65
<b>Hedge "C" Result</b>	\$ -	\$ -	\$ -	\$ -	\$ 200	\$ 53	\$ (29)	\$ (78)	\$ (33)	\$ 52	\$ 67	\$ 57	\$ 288
Cost Net of Hedge:	\$ 29,663	\$ 26,252	\$ 25,898	\$ 17,748	\$ 18,258	\$ 18,569	\$ 20,648	\$ 20,282	\$ 23,006	\$ 21,357	\$ 24,626	\$ 31,972	\$ 278,278
per Unit Cost:	\$ 65.01	\$ 66.17	\$ 65.50	\$ 56.85	\$ 65.40	\$ 64.16	\$ 72.58	\$ 62.24	\$ 60.45	\$ 56.39	\$ 64.12	\$ 75.64	\$ 64.63
<b>Hedge "D" Result</b>	\$ -	\$ -	\$ -	\$ -	\$ 114	\$ 30	\$ (17)	\$ (45)	\$ (19)	\$ 30	\$ 38	\$ 33	\$ 164
Cost Net of Hedge:	\$ 29,663	\$ 26,252	\$ 25,898	\$ 17,748	\$ 18,172	\$ 18,547	\$ 20,660	\$ 20,315	\$ 23,020	\$ 21,334	\$ 24,598	\$ 31,947	\$ 278,155
per Unit Cost:	\$ 65.01	\$ 66.17	\$ 65.50	\$ 56.85	\$ 65.09	\$ 64.08	\$ 72.63	\$ 62.34	\$ 60.49	\$ 56.33	\$ 64.04	\$ 75.58	\$ 64.60

## Appendix C – 2009 Financial Summary

### Town of Ingersoll - 2009 Commodity Summary

Date	kWh	Spot Cost	Prov. Benefit	OPG Rebate	Swap Value	WattsWorth Strategy				RPP Base Cost	Difference	
						Settlement	WW	RPP	Net		\$	%
Jan-09	451,790	\$ 24,178	\$ 5,451	\$ (698)	\$ -	\$ -	\$ 28,931	\$ 82	\$ 29,013	\$ 29,260	\$ (247)	-1%
Feb-09	392,819	\$ 18,205	\$ 2,039	\$ -	\$ -	\$ -	\$ 20,244	\$ 39	\$ 20,284	\$ 25,421	\$ (5,137)	-20%
Mar-09	391,482	\$ 11,140	\$ 3,714	\$ -	\$ -	\$ -	\$ 14,854	\$ 30	\$ 14,884	\$ 25,328	\$ (10,444)	-41%
Apr-09	309,118	\$ 4,960	\$ 9,335	\$ -	\$ -	\$ -	\$ 14,295	\$ -	\$ 14,295	\$ 19,985	\$ (5,689)	-28%
May-09	276,410	\$ 7,082	\$ 11,001	\$ -	\$ 320	\$ -	\$ 18,404	\$ -	\$ 18,404	\$ 18,132	\$ 272	2%
Jun-09	286,557	\$ 6,163	\$ 7,995	\$ -	\$ 424	\$ -	\$ 14,583	\$ -	\$ 14,583	\$ 18,803	\$ (4,220)	-22%
Jul-09	278,888	\$ 5,069	\$ 9,761	\$ -	\$ 548	\$ -	\$ 15,378	\$ -	\$ 15,378	\$ 18,305	\$ (2,927)	-16%
Aug-09	296,231	\$ 7,408	\$ 12,827	\$ -	\$ 348	\$ -	\$ 20,583	\$ -	\$ 20,583	\$ 19,435	\$ 1,148	6%
Sep-09	349,155	\$ 6,894	\$ 11,732	\$ -	\$ 460	\$ -	\$ 19,086	\$ -	\$ 19,086	\$ 22,936	\$ (3,850)	-17%
Oct-09	371,309	\$ 10,612	\$ 15,335	\$ -	\$ 325	\$ -	\$ 26,272	\$ -	\$ 26,272	\$ 24,394	\$ 1,878	8%
Nov-09	380,266	\$ 10,053	\$ 12,549	\$ -	\$ 348	\$ -	\$ 22,949	\$ -	\$ 22,949	\$ 25,362	\$ (2,413)	-10%
Dec-09	418,496	\$ 14,969	\$ 15,903	\$ -	\$ 260	\$ -	\$ 31,131	\$ -	\$ 31,131	\$ 27,918	\$ 3,213	12%
<b>Total 2009</b>	<b>4,202,521</b>	<b>\$ 126,735</b>	<b>\$ 117,641</b>	<b>\$ (698)</b>	<b>\$ 3,033</b>	<b>\$ -</b>	<b>\$ 246,711</b>	<b>\$ 150</b>	<b>\$ 246,862</b>	<b>\$ 275,279</b>	<b>\$ (28,417)</b>	<b>-10.3%</b>

## Appendix D - Schedule of Account Pools

Street Lights	
Acct #	Description
00159813-00	STREETLIGHTS
00161165-00	STREETLIGHTS
00161159-00	STREETLIGHTS
00161457-00	STREETLIGHTS
00161458-00	STREETLIGHTS
00161459-00	STREETLIGHTS

Large NSLS	
Acct #	Description
00007501-00	50 WILSON ST
00007502-00	50 WILSON ST
00016215-01	INGERSOLL ST
00016350-04	269 INGERSOLL ST
00092260-00	CHEESE MUSEUM
00100350-03	132 THAMES ST S UPPER
00100351-00	132 THAMES ST S LOWER
00100520-01	121 THAMES ST N

Peaking Interval	
Acct #	Description
00100549-00	130 OXFORD ST
00161052-00	121 THAMES ST N
00100499-04	355 WELLINGTON ST

LSC and Non-Peaking Interval	
Acct #	Description
00100580-03	97 MUTUAL ST
00100606-01	80 PEMBERTON ROAD

Small NSLS	
Acct #	Description
00016495-00	THOMPSON DRAIN
00090060-02	1 CHARLES ST W
00090200-10	INNES ST
00090210-10	INNES ST
00090821-00	OXFORD ST
00091570-00	160 THAMES ST S
00092250-05	CENTENNIAL PARK
00092251-03	CENT PARK S/LIG
00092265-00	190 CANTERBURY ST
00092660-04	WELLINGTON ST
00092661-03	CEN PARK CAM
00092662-03	WELLINGTON ST
00092665-03	WELLINGTON ST
00092750-10	CANTERBURY ST
00092751-03	CANTERBURY ST
00092800-02	LIONS CLUB PARK
00092802-03	WELLINGTON ST
00092810-03	VICTORIA PARK
00092820-03	VICTORIA PARK
00092850-11	CHISOLM DR
00092900-10	CHISOLM DR
00093801-00	CHARLES ST E
00094960-04	38 THAMES ST S
00099887-01	INNES ST
00100553-00	TRAFFIC LIGHTS
00100581-03	97 MUTUAL ST
00101127-00	80 PEMBERTON ROAD
00101129-00	97 MUTUAL ST
00101130-00	355 WELLINGTON ST
00101140-00	130 OXFORD ST
00159711-00	CANTERBURY ST
00160487-00	133 THAMES ST S
00160499-00	CANTERBURY ST
00161166-00	TRAFFIC LIGHTS
00161240-00	WELLINGTON ST
00161456-00	TRAFFIC LIGHTS
00161464-00	TRAFFIC LIGHT