Table of Contents
for NS Power Direct Evidence and Testimony of Experts

Appendices

Appendix A – NS Power RES Compliance Plan
Appendix B – Utility Performance Benchmarking Analysis
Appendix C – OM&G Detailed Variance Analysis
Appendix D – CEA 2009 Generation Equipment Status Report
Appendix E – OM&G Five Year Forecast Summary
Appendix F – Expert Testimony – K. McShane
Appendix G – Unmetered Class Cost of Service and Pricing Study Review
Appendix H – ELI 2P-RTP – Change of Billing Provisions
Appendix I – Combined Revenue Effect of All Rate Changes in 2012
Appendix J – Proposed Changes to Regulations

Acronym List

Acronym	Definition
2009C	2009 Compliance
2009C restated	2009 Compliance restated
2011F	2011 Forecast
2012F	2012 Forecast
AA	Actual Adjustment
ACE	Annual Capital Expenditure
AO	Administrative Overhead
ARO	Asset Retirement Obligation
ATL	Above-the-Line
BA	Balance Adjustment
BCF	Base Cost of Fuel
Bcf	Billion cubic feet
BTL	Below-the-Line
Btu	British Thermal Unit
CAD	Canadian Dollar
CBL	Customer Baseline Load
CEA	Canadian Electricity Association
CO_2	Carbon dioxide
COSS	Cost of Service Study
CP	Commercial Paper
CPI	Consumer Price Index
CWC	Cash Working Capital
DBRS	Dominion Board Rating Service

Acronym	Definition
DCRR	Demand Side Management Cost Recovery Rider
DSM	Demand Side Management
ELI 2P-RTP	Extra Large Industrial Two-Part Real Time Pricing
EMO	Emergency Management Office
ENSC	Efficiency Nova Scotia Corporation
EOC	Emergency Operations Centre
ESRP	Emergency Services Restoration Plan
FAM	Fuel Adjustment Mechanism
FFO	Funds from Operations
FOB	Free-on-Board
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GR	Generation Replacement
GRA	General Rate Application
GRLF	Generation Replacement and Load Following
GW	Gigawatt
GWh	Gigawatt hour
HFO	Heavy Fuel Oil
Hg	Mercury
HPS	High Pressure Sodium
IBEW	International Brotherhood of Electrical Workers
IPP	Independent Power Producer

Acronym	Definition
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light Emitting Diode
LF	Load Following
LFO	Light Fuel Oil
LIIR	Large Industrial Interruptible Rider
LIR	Large Industrial Rate
LNG	Liquefied Natural Gas
LPS	Low Pressure Sodium
LWS	Lower Water Street
M&NP	Maritimes & Northeast Pipeline
M&NP-US	Maritimes & Northeast Pipeline – U.S.
MAE	Mersey Additional Energy
MMBtu	Millions of British Thermal Units
MT	Metric ton
MTN	Medium Term Notes
MV	Mercury Vapour
MW	Megawatt
MWh	Megawatt hour
NOx	Nitrous oxide
NSR	Net System Requirement
NYH	New York Harbour
OM&G	Operating, Maintenance & General
petcoke	Petroleum coke

Acronym	Definition
POA	Plan of Administration
PPA	Power Purchase Agreement
PTMT	Point Tupper Marine Terminal
R/C	Revenue-to-Cost
RES	Renewable Energy Standard
ROE	Return on Equity
S&P	Standard & Poor’s
Sears	Sears, Roebuck and Company
SO_2	Sulphur dioxide
SOEP	Sable Offshore Energy Project
UARB	Nova Scotia Utility and Review Board
USD	United States Dollar

1.0 INTRODUCTION

The costs involved in making electricity have increased since general rates were last adjusted on January 1, 2009. Nova Scotia Power has been able to avoid filing a General Rate Application for three years, thanks to prudent management of expenses, accelerated tax deductions from renewable energy projects, and the ability of the Utility and Review Board to adjust fuel expense recovery through the Fuel Adjustment Mechanism (FAM). This has been to the benefit of our customers.

Our forecast of costs for 2012 necessitates our first General Rate Application in three years. Using current rates, 2012 revenues would be $94.4 million less than forecasted requirements of $1.339 billion. Therefore, this Application requests an average revenue increase of 7.3 percent effective January 1, 2012. For the average residential customer, this would increase the price of electricity by roughly $8 per month. We also foresee the need for smaller increases in 2013 to 2015.

We know rate increases create challenges for our customers. They can add to the cost of running households and businesses. Nova Scotia Power strives to ensure that electricity prices are as low as possible for our customers, and that any price changes are as manageable as possible.

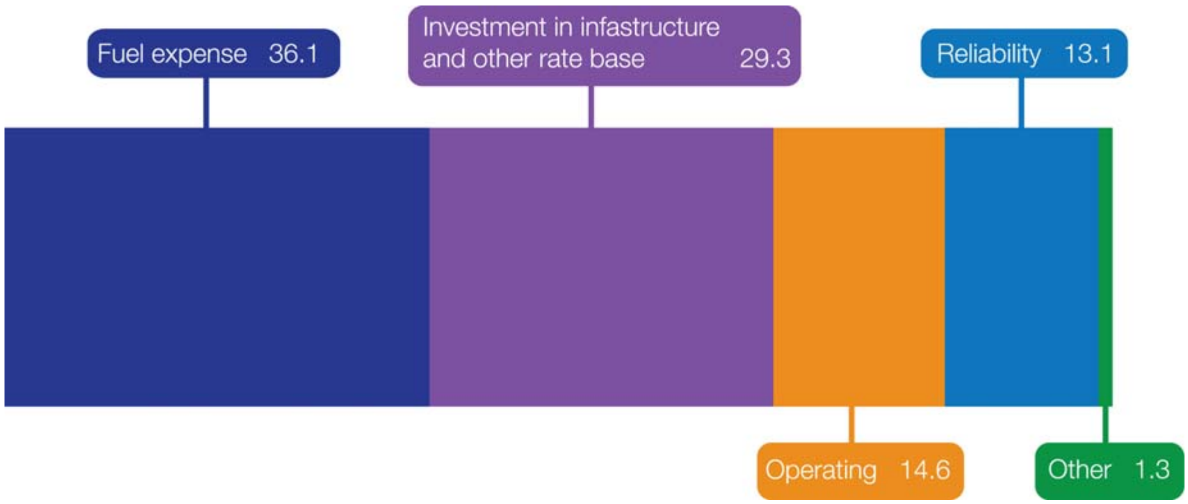
Later this year, the UARB will set the charges for fuel costs already incurred in 2010, as well as for the programs provided by Efficiency Nova Scotia. With these amounts added, we estimate a total impact of 9.2 percent, averaged across all customer classes. Actual fuel costs during 2011 will also be reviewed later this year although it is too early to estimate the outcome at this time.

Last month, NS Power initiated a public discussion with customer representatives aimed at developing a multi-year approach to smooth increases in electricity rates through 2014. Those discussions are ongoing, and reflect NS Power's preferred alternative path forward as a way to help customers during this period of transformation. We will keep the Board apprised of progress on these discussions, even as the traditional rate setting process is followed.

The specifics of the $94.4 million in cost pressures are detailed in this Application. Most of the costs can be attributed to four drivers:

- **Higher fuel costs ($36.1 million) –** driven by volatile foreign coal;
- **Increased investment ($29.3 million)–** Investments in infrastructure and increased working capital requirements since general rates were last set, are partially but not fully offset by tax savings;
- **Operating and sustaining our workforce ($14.6 million) –** Wage increases since January 1, 2009, pension, succession planning, and new positions;
- **Focus on reliability ($13.1 million) –** storm hardening our transmission and distribution systems, trimming back or removing trees that could come in contact with lines, and storm recovery.

Figure 1.1



Note: Numbers elsewhere in the filing may differ slightly due to rounding.

1.1 Fuel

World prices for coal and petcoke keep rising – 30 percent in the last six months alone. Producing more of Nova Scotia's electricity from renewable sources is displacing some of this imported "solid fuel" and helps protect customers from future price volatility. That strategy is in place and producing results. For the moment, however, two-thirds of the electricity Nova Scotians use is made by burning coal and petcoke.

The tightening of provincial emissions caps since 2009 has increased our reliance on low-sulphur coal. Premium fuels help us comply with new public policy requirements for emissions, but costs for these fuels are increasing.

Section 2 of this Application includes a detailed description of the increased fuel costs. The base cost of fuels in 2011 was $537.8 million. The fuel cost forecast for 2012 is $573.9 million, an increase of $36.1 million.

1.2 Infrastructure Investment

In the period from the last time general electricity rates were adjusted in 2009, to the end of 2012, NS Power will have invested more than $900 million in capital projects. We are investing in Nova Scotia to expand the use of renewable energy, reduce air emissions, and maintain and improve plant efficiency. These investments are creating jobs and providing lasting value for customers. Renewable investments are also bringing tax reductions that are largely offsetting the costs of new renewable projects in the early years. In 2012, NS Power is forecasting a decrease in taxes of $72 million.

Last October, NS Power filed a depreciation study with the Board, and this winter, the company and its major customer representatives, including the Consumer Advocate, came to an agreement to stabilize depreciation rates. This Application proposes depreciation rates set forth in that agreement. The investments in infrastructure made since the last General Rate Application in 2009, using the new rates, will cause our depreciation expense to grow by $33.0 million in 2012 (revenue requirement after tax effect will be $47.8 million). In the absence of the depreciation settlement agreement, 2012 depreciation costs could have been much higher. This is an example of how working together to achieve a common goal can serve the needs of our customers and the utility.

Financial analysts who follow the utility industry view timely recovery of capital investments as a key indicator of a utility’s financial health. Timely recovery of these costs will encourage rating agencies to maintain their positive view of Nova Scotia Power’s credit rating. This will help keep the costs of the debt needed to invest in further improvements – costs that ultimately affect customer rates – as low as possible.

Overall, investment in infrastructure and other rate base items, less tax benefits, accounts for $29.3 million of 2012 incremental revenue requirement.

1.3 Operating and Workforce

We run an efficient, cost-effective business in large part because we have excellent employees who are focused on keeping costs as low as possible for our customers. And we do it well. An independent consultant engaged by the Board in 2008 to review NS Power’s operating, maintenance, and general (OM&G) expenses concluded that NS Power appears to be well run by management. That continues to be the case. We have updated this previous benchmarking work to demonstrate to our customers that NS Power's operating expenses compare favourably to other Canadian utilities.

That said, Nova Scotia Power’s OM&G expenses are increasing. Our investment in new infrastructure requires us to attract, develop, and retain skilled employees, particularly in engineering, project management, cost control, and support functions. NS Power has a multi-year collective agreement that includes wage increases through to 2012 for unionized workers such as power line technicians, meter readers, and power plant and hydro employees. Effective management of the collective agreement and continued good relations with the International Brotherhood of Electrical Workers are important elements in delivering improved reliability. Many of our workers have skills that are in high demand in the booming resource sector across Canada, and we need to retain them. Non-union employees, including engineers, technologists, project managers, accountants and customer care representatives, have received industry standard wage increases since the last time electricity rates were set. Pension costs have increased as a result of actuarial assumptions and market performance.

Overall, workforce related expenses account for $14.6 million of the 2012 cost increases.

1.4 Reliability

The increased frequency of severe weather over the past decade has added to the workload of our transmission, distribution, and customer service departments. Nova Scotians have told us they want more reliable service and better customer communications. In response, we have invested in programs that help reduce outages caused by trees interfering with power lines. We have developed and are implementing a five-year capital program to improve system reliability. We have also overhauled our storm communications systems. In this Application, we propose additional investment in these areas that are key to improving customer experience.

Overall, reliability investments account for $13.1 million of our 2012 cost pressures.

1.5 Changing Our Business

This Application comes at a time of great change for NS Power and the province of Nova Scotia. We are changing the way we produce and consume energy. We're cutting our use of high-carbon coal and petcoke, and vastly increasing our use of renewable wind and biomass.

Our move to renewables accounts for a relatively small part of the cost pressures necessitating this application. As mentioned earlier, the tax benefits of investment in renewable projects have helped us avoid a General Rate Application in recent years. They're helping customers in 2012, as well. We forecast our tax expenses will be $72 million lower in 2012 than the last time rates were set (2009 Compliance Filing), in part due to renewable energy tax deductions.

Wind farms and other renewable investments are benefitting customers today, and will for generations to come. They are protecting and improving our environment. They are reducing our exposure to volatile world fuel prices. They are allowing us to spend money in Nova Scotia's economy instead of on foreign coal.

This change is the result of government policy reflecting the will of Nova Scotians. And it has made our small province a leader in the global effort to control climate change. Nova Scotia is the only jurisdiction in North America to impose a hard cap and reduction on greenhouse gas emissions in the electricity sector. We are pioneering the development of in-stream tidal energy with the goal of harnessing the phenomenal power of the Bay of Fundy tides.

NS Power has installed new burners that reduce the production of nitrogen oxide at our Lingan, Trenton, and Point Tupper generating stations. We have installed mercury capture systems. On our own, and working with independent producers, we have brought 119 wind turbines on line since 2009. One day last month, 20 percent of Nova Scotia's electricity was coming from wind farms – that would not have been possible just a few years ago.

By 2020, 40 percent of our electricity will come from renewables. Our dependence on coal will continue to reduce in the coming years. However, even at reduced usage, our coal plants continue to have economic value for customers.

1.6 Conclusion

Section 3 of the Standardized Filing in this Application sets forth a detailed financial outlook for the 2012 test year, based on forecasts of revenue, fuel costs, depreciation, and other items affecting our operations.

In this Application, NS Power also requests an adjustment to the allowed rate of return. NS Power must compete for debt and equity with other utilities with a similar risk profile. A competitive rate of return is especially important during this period of historic capital investment. It helps us get the right mix of equity and debt to build and maintain the assets we need – ultimately keeping costs lower for customers than might otherwise result.

With this Application, Nova Scotia Power seeks an order, effective January 1, 2012, approving:

a) The 2012 revenue requirement set out in this Application to enable Nova Scotia Power to recover the reasonable costs of providing service to customers and to meet its financial obligations, including provision for a just and reasonable return; and, as a consequence, the rates, charges and regulations requested in this Application.

b) A change in the Extra-Large Industrial Two-Part Real-Time Pricing tariff described in this Application.

c) Adjustments to the rates, charges, or regulations as needed to reflect decisions and directives in Nova Scotia Power-related proceedings, or as the UARB may determine in response to this Application.

d) An increase on the return on common equity from the current 9.35 percent to 9.6 percent, with a corresponding adjustment to the range of return.

e) NS Power's portion of the Point Tupper Wind Farm OM&G, financing, and depreciation costs, currently recovered through the Fuel Adjustment

Mechanism, be recovered through the fixed rate component NS Power's rates, in the traditional manner.

In this Application, we have provided information to the Utility and Review Board and stakeholders that identifies and explains key issues. NS Power looks forward to an application process that is efficient, collaborative, and well-managed. We welcome opportunities to work with the Board and stakeholders to improve the pre-hearing and hearing processes and to resolve matters in a constructive and collaborative manner, as we have done successfully in several recent proceedings. In particular, we will continue to work with our customers and their representatives to try to find a multi-year approach that will provide more stable electricity prices in the short term, and lower than might result from the traditional rate-making process.

2.0 FUEL AND PURCHASED POWER

Fuel costs are rising. Nova Scotians see this when they buy gas for the family car, propane for the barbeque, and fuel oil for the furnace. Nova Scotia Power sees it when we buy coal and petroleum coke for the Lingan, Trenton, Point Aconi and Point Tupper power generating stations.

Fuel prices have swung dramatically over the last decade — but always around a relentlessly rising trendline.

Fuel constitutes the largest single cost of operating Nova Scotia's electric utility, and when any utility's largest single cost input moves continually higher, it is bound to affect rates.

Throughout this Application, we have stressed the big changes taking place in the way Nova Scotia Power generates electricity. An important goal of this dramatic change is to reduce the dominant role of solid fuel in our cost structure. We are reducing the proportion of electricity produced from imported coal and petcoke, and increasing the amount from local, renewable sources like wind and biomass. By lessening our reliance on fuel, we will gradually achieve more stable electricity prices for our customers. In the interim, much of our power will continue to come from coal, petcoke, and natural gas.

In 2009, the UARB recognized the impact of volatile fuel prices by approving a Fuel Adjustment Mechanism. The FAM adjusts the price of electricity at the start of each year to reflect changes in fuel costs and fuel cost recovery. The FAM Plan of Administration (POA) prescribes the method for calculating the fuel costs on which rates are based. It establishes a Base Cost of Fuel (BCF), which is a projection of fuel costs expected in the test year, 2012. It also prescribes a set of adjustments once actual fuel costs are known.

The FAM includes an incentive component to give Nova Scotia Power a direct financial interest in managing fuel costs effectively. The FAM resets the Base Cost of Fuel every two years, and during a General Rate Application (GRA) such as this one.

The UARB last approved a reset of the BCF in November 2010, based on projected fuel costs for 2011. Since then, fuel costs have remained volatile, and costs for coal and petcoke have continued to rise.

This section deals with the reset of the BCF required as part of this GRA. It provides projected fuel costs for the 2012 test year, including the projected cost of power purchased from other producers. It includes information about our fuel procurement strategy, our fuel portfolio, and our 2012 fuel forecast.

2.1 Overview

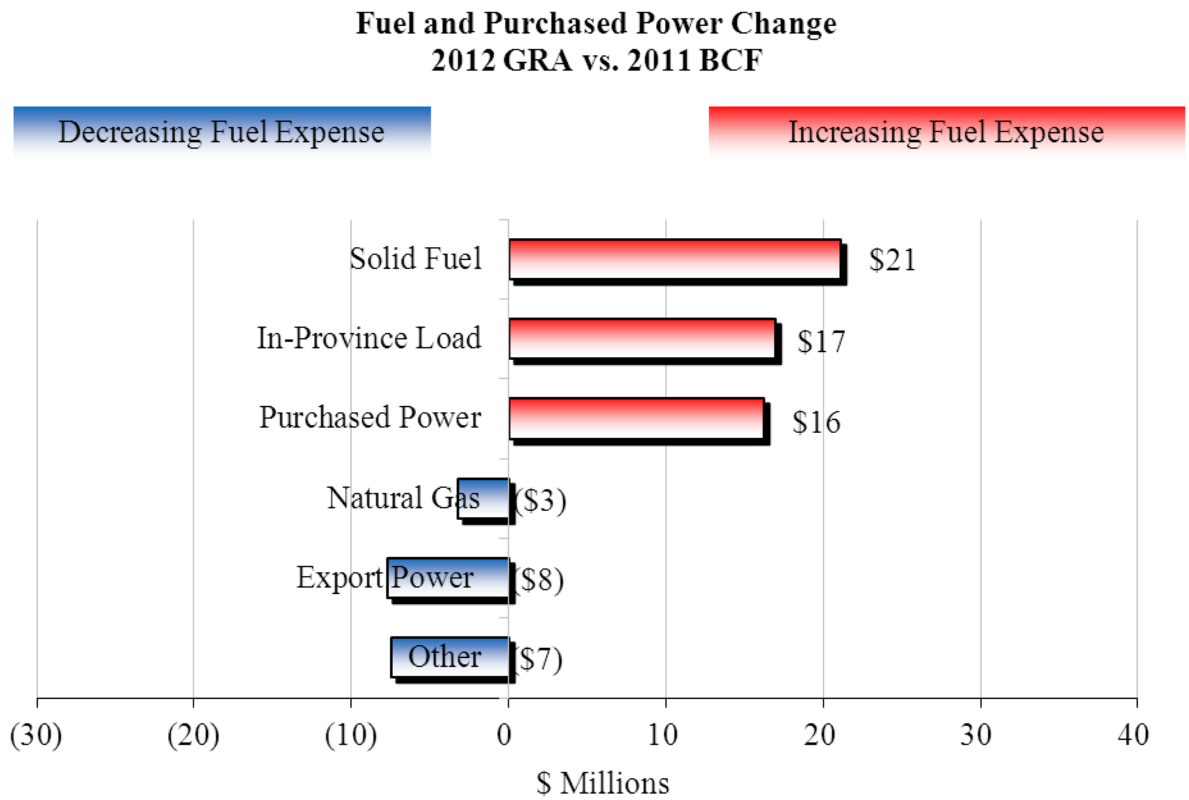
Current rates include fuel and purchased power expenses of $537.8 million, which is the 2011 BCF approved by the UARB. For the 2012 test year we project a fuel cost of $573.9 million, or $36.1 million higher than the amount included in the 2011 Base Cost of Fuel. The major components of this cost increase are shown in Figure 2.1 and Figure 2.2. The sections below describe each component in more detail.

One component of fuel cost increase is the need to seek out low sulphur and low mercury coal to help meet tighter emission restrictions. On July 22, 2010, the Nova Scotia government announced it would change mercury regulations under the Provincial Air Quality Regulations, to better align them with provincial standards for nitrogen oxides (NOx), sulphur dioxide (SO_2), and carbon dioxide (CO_2), and compliance with Provincial renewable electricity regulations. The changes were reflected in an Order-in-Council amending the Province's air quality regulations which was issued December 7, 2010.

This change enables Nova Scotia Power to partially offset fuel cost increases by using lower cost coals and reducing additives.

Nova Scotia Power has also been able to increase its use of the one fuel whose cost has not increased significantly in recent years: that being natural gas.

Figure 2.1



Solid Fuel

Solid fuel prices, volume, and adjustments contribute $21.1 million to the total 2012 fuel cost increase. This is primarily due to the global escalation in solid fuel prices. This increase in pricing is offset by a forecasted decrease in the volume of coal required as we expect gas to be a more economical fuel choice in much of 2012.

In-Province Load

As discussed in Section 8, we expect the 2012 in-province load to be higher than the forecast for the 2011 BCF. This is projected to add $16.9 million to fuel costs.

Purchased Power Price

This item is changing primarily because the price NS Power will pay to purchase power has risen since the 2011 Base Cost of Fuel reset. Secondarily, we also forecast to buy 111 GWh more energy than we forecast in the 2011 BCF. The additional energy is from Independent Power Producers (IPPs) to enable us to meet Provincial renewable electricity regulations.

Natural Gas

Nova Scotia Power’s forecasted price for natural gas has decreased in 2012, compared to the 2011 BCF. Because the price of gas is increasingly attractive, gas volumes have increased since 2011.

Export Power

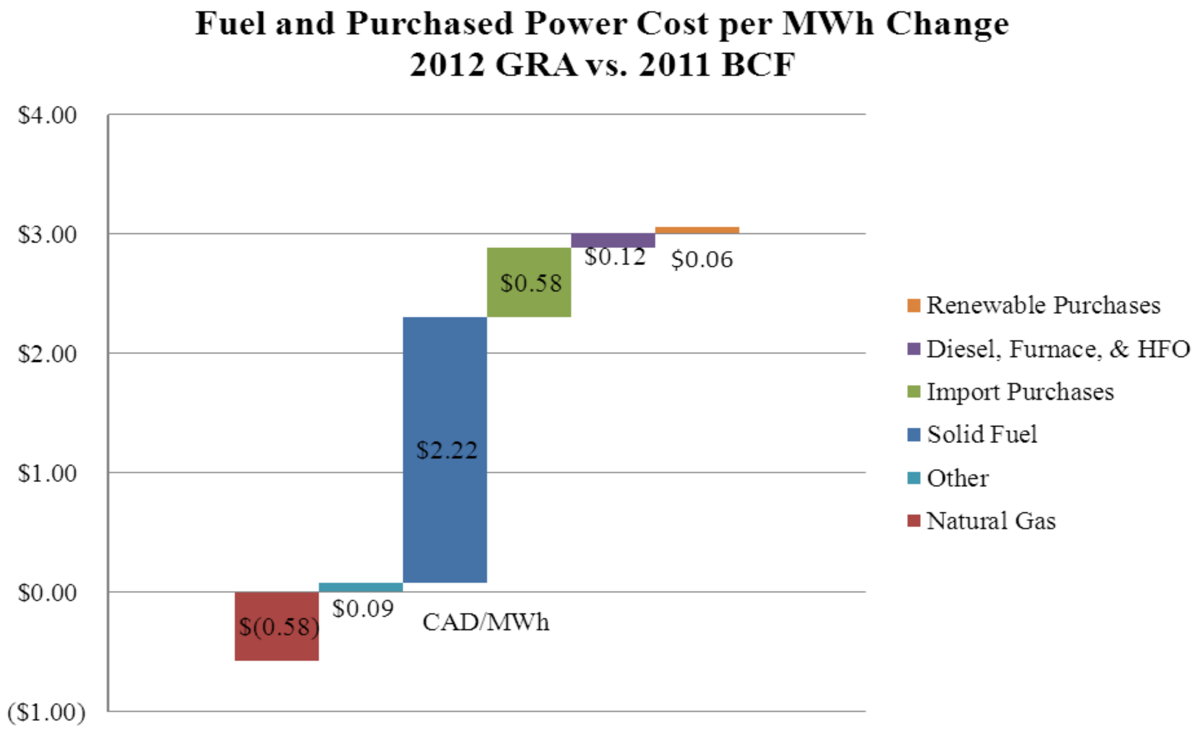
The prescribed FAM forecasting method assumes we will use 50 percent of available capacity at Tufts Cove Units 2 and 3 for export. The forecast price for gas in the test year makes it an attractive alternative to solid fuels, so we now expect to burn more gas at Tufts Cove in 2012 than we predicted in the 2011 BCF. This increase in generation at Tufts Cove for use within Nova Scotia means a reduction in available capacity for export at Units 2 and 3. This results in a forecast reduction in export generation of 128 GWh, an offsetting increase in export prices which reduces associated fuel costs by $8.0 million.

Other

This category includes a decrease in forecast mercury capture additives of $9.7 million from the 2011 BCF, partially offset by increases in heavy fuel oil (HFO), diesel, and furnace oil prices.

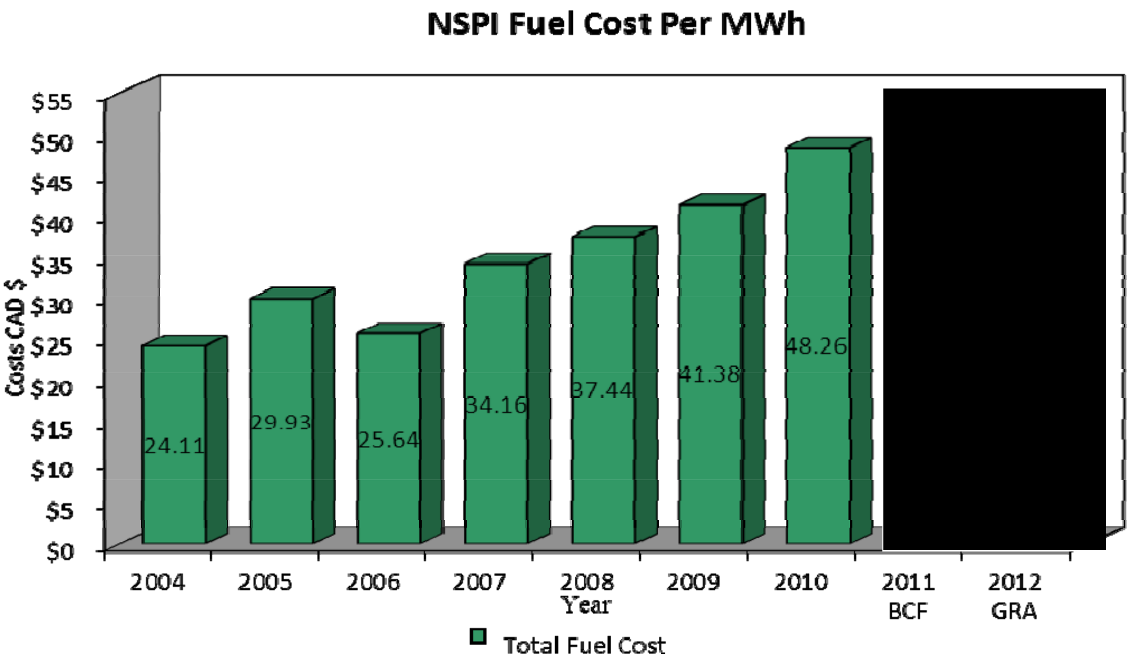
As Figure 2.2 shows, various changes in 2012 fuel costs over 2011 BCF result in an increase in the fuel cost per megawatt hour of electricity produced. We forecast an increase from $42.77/MWh in the 2011 BCF to $45.25/MWh in the 2012 GRA. This represents a 5.8 percent increase, and it is consistent with the trend in rising fuel prices as shown in Figure 2.3.

1 **Figure 2.2**



2
3

Figure 2.3
REDACTED



Note: 2011 and 2012 columns in this figure are confidential.

2.2 Fuel Testimony

Nova Scotia Power continues to experience the effects of world market forces on its fuel costs. In 2012, we project an increase in fuel and purchased power costs of $36.1 million, compared to the 2011 BCF.

This section outlines NS Power's mix of generating capacity and comments on market. NS Power's Fuel Procurement Strategy and the fuel portfolio are discussed in detail. The fuel forecast methodology and the details of the 2012 forecast are described, highlighting the following topics:

- Natural Gas and Heavy Fuel Oil

- Solid Fuel
- Renewable Energy
- Foreign Exchange
- Effect of Load on the Cost of Generation

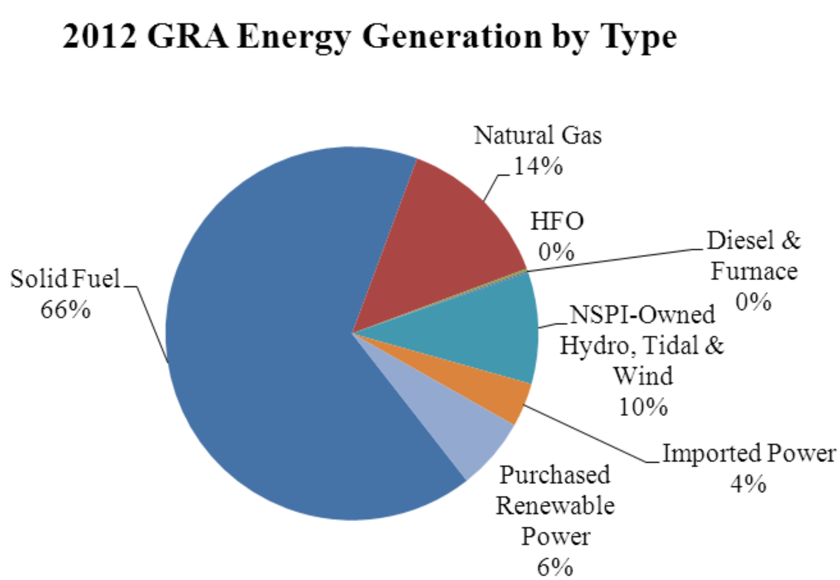
2.2.1 Nova Scotia Power's Generation by Fuel Type

Nova Scotia Power has 2,381 MW of generating capacity. Solid fuel fired capacity makes up 52 percent, natural gas and oil fired facilities comprise 29 percent, with hydro, tidal and wind providing the remaining 19 percent of NS Power's total generating capacity.

The generation fleet is economically dispatched based on each plant's operating costs and is subject to environmental and reliability constraints. As a result, 80 percent of NS Power's energy is forecast to be produced from fossil fuel-burning plants, with 66 percent forecast from solid fuel and 14 percent forecast from natural gas, heavy fuel oil, and light fuel oil (LFO). The remaining 20 percent of NS Power's energy requirement is forecast to be provided from a combination of NS Power-owned hydro, wind generation, and purchased power.

Figure 2.4 provides a breakdown of the 2012 Energy Generation by type.

Figure 2.4



2.2.2 Fuel Portfolio

Nova Scotia Power procures and manages a reliable fuel supply with a diversified portfolio of fuel types, suppliers, contract terms, and pricing structures seeking to produce energy cost stability for customers. NS Power tests new fuels to increase fuel supply competition and diversity of supply. Financial derivatives and fixed price contracts are employed to reduce the impact of fuel price volatility on customers. NS Power's objective is to dispatch and consume fuel to yield the lowest cost while complying with all applicable policies, procedures, and meeting reliability, safety and environmental requirements.

The following sections describe NS Power's portfolio development by fuel type.

Impact of Relative Changes in Fuel Pricing

NS Power burns natural gas and/or HFO at Tufts Cove. Tufts Cove Units 1, 2 and 3 are capable of using either fuel while Units 4 and 5[1] and 6 burn only natural gas. In Tufts Cove Units 1, 2 and 3, the commodity with the most economic market price is consumed in order to provide the best value for customers. With the increase in HFO prices in recent years, natural gas has become the more economic choice, increasing the gas burned in these units and reducing the quantities of HFO required. Tufts Cove units were historically on the margin, which means they were usually the last units dispatched to meet system load requirements.

Global coal and petcoke prices have been volatile over the last three years. After reaching record highs in July 2008, coal prices had plummeted by early 2009 due to the global financial crisis. Since mid-2009, global coal prices have risen but have not returned to the levels reached in mid-2008. The global coal market is being driven by strong demand for metallurgical coals, primarily from Asia. The price recovery of petroleum coke since 2008 has been much stronger than the price recovery of coal.

The last few years have seen natural gas and coal units compete on economics. As a result, natural gas consumption, as a percent of fuel generation, has increased from 8 percent in 2007 to 20 percent in 2010. NS Power continuously monitors the relative costs of its fuel sources in order to create an economic dispatch order that minimizes the overall cost of generation, with the benefits provided to customers through the FAM.

[1] Tufts Cove Units 4 and 5 are GE LM6000 combustion turbine, together with Tufts Cove Unit 6, will comprise NS Power's new combined cycle facility.

Natural Gas

NS Power applies four general principles when considering natural gas supply planning and acquisition. The first is that we optimize gas supply around system needs. This involves understanding the drivers of system gas requirements and evaluating all gas and power assets and operational tradeoffs. The second principle is to have planning reflect an understanding of market dynamics and their effects on gas supply options and pricing. This is particularly true of the new gas supply developments in Nova Scotia/New Brunswick, the Maritimes & Northeast Pipeline (M&NP) capacity situation and gas and oil price volatility. The third principle is that NS Power should develop a supply portfolio approach [redacted]. The fourth principle is to maintain flexibility in order to realize value as opportunities arise.

Gas market structure and developments are a dominant factor in NS Power's assessment of its gas supply options. Natural gas markets remain volatile and prices can move dramatically, often in unpredictable ways. NS Power buys and sells gas indexed to specific market hubs in the northeastern United States – currently [redacted].[2] Prices at these hubs respond to local market conditions, as well as broader market developments. During the summer of 2008, when oil prices reached over $140 per barrel, natural gas also peaked at near $15 per MMBtu. Since then, both oil and natural gas prices have fallen, with natural gas falling farther relative to oil reflecting large increases in North American supply. As a result, not only have gas prices been favourable to HFO, they have also been favourable to coal prices during some periods in 2009 and 2010, leading to a greater gas burn at Tufts Cove than historically has been the case.

[2] [redacted]

Major developments in the Maritimes also affect how we purchase natural gas. Production from the Sable Offshore Energy Project (SOEP) continues to decline. In July 2009, Maritimes & Northeast Pipeline – U.S. (M&NP-US) sought and received an amended Presidential Permit to allow it to export natural gas to Canada from the United States, in part to ensure supply access when SOEP is not operating. EnCana's planned new production from Deep Panuke is currently scheduled to begin in November 2011.

The other major development in the Maritimes gas market is the emergence of Repsol as a major supplier in the region. In the fall of 2009, a new supply source, the Canaport LNG facility at Saint John, New Brunswick began commercial operations. The facility has a one billion cubic feet (Bcf) per day output capacity. Repsol had previously secured most of the M&NP-US capacity from Baileyville, Maine to Dracut, Massachusetts, approximately 730,000 MMBtu per day, in order to be able to supply regasified liquefied natural gas (LNG) from Canaport to U.S. markets. In 2009, Repsol announced that it had secured all of the future production from Deep Panuke, all of the on-shore production from Corridor Resources, and all of the uncommitted ExxonMobil SOEP production.

NS Power is well positioned with adequate gas supplies to meet customer requirements while maintaining flexibility to respond to market developments. The prices at which we expect to purchase supply, as reflected in this rate filing, is tied to market indices and based on market conditions. Our approach to securing gas supply is based on the principles for supply acquisition – understanding requirements, taking into account market dynamics that affect our options, employing a portfolio approach, and maintaining the flexibility to respond to developments.

Oil

Our HFO strategy consists of two parts, physical purchases and financial hedging. We buy HFO under a [redacted] with pricing tied to a New York Harbour (NYH) market index. [redacted].

HFO and natural gas are both priced against market indices. NS Power's Fuel Manual outlines the hedging program for these fuels for the purpose of reducing volatility. [redacted].

Solid Fuel

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.

Figure 2.5 describes the portfolio position from 2011 to 2015 as well as the mix and length of contracts.

Figure 2.5

NS Power Solid Fuel Portfolio Table
(in thousands of metric tonnes)
As at December 31, 2010

YEAR	2011 BCF	2012	2013	2014	2015
Contracted Open Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted percentage Open percentage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Open	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

We review our commitments on an on-going basis, monitoring our requirements and changes in market conditions to ensure the portfolio to be optimized. Our fuel contracts are summarized in Figure 2.6 and outlined in the following sections.

Figure 2.6

Summary of Portfolio Status
(in thousands of metric tonnes)
As at December 31, 2010

Supplier	Mine Source	Country	2011 BCF	2012	2013	2014	2015
Low Sulphur Positions Required			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Open			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid & High Sulphur Positions Required			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Open			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Domestic Positions Required			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Open			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Petroleum Coke Positions Required			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Open***			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Mid-sulphur medium-term agreement [redacted] following the 2011 BCF for [redacted] in 2011, and mid-sulphur short-term agreement [redacted] in 2011.

**3 year Domestic contract signed [redacted]

***Petroleum coke short-term agreement [redacted] following the 2011 BCF, for [redacted] in 2011.

Long-Term Contracts

NS Power engages in long-term commitments for solid fuel that will be consumed for [redacted].

NS Power [redacted] long-term commitments for solid fuel as follows:

Figure 2.7

[redacted]

Medium-Term Contracts

NS Power engages in medium-term commitments for solid fuel that will be consumed for [redacted].

NS Power [redacted] medium-term contracts as follows:

Figure 2.8

[redacted]

**3-year Domestic contract signed [redacted]

Short-Term Contracts

Up to [redacted] of our solid fuel requirements may be purchased on a short-term basis. These purchase decisions depend on factors such as changes in fuel requirements, prevailing market conditions and volume optionality on long and medium-term agreements. The short-term commitments also include coal purchases for test burns and for emissions management.

Transportation

We receive 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 [redacted]. These agreements provide for [redacted] of the freight requirements in 2012. Some of our fuel suppliers also provided freight for their products. [redacted].

2.2.3 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.

The forecast is derived from industry-standard generation models that dispatch our generating capacity to meet projected load requirements in a least-cost manner, subject to the 2012 emission caps of 72,500 tonnes of sulphur dioxide, 9,340,000 tonnes of carbon dioxide, 21,365 kilograms of nitrogen oxides, and 100 kilograms of mercury (Hg).

This forecast has been prepared in compliance with the methodology in Appendix B of the FAM Plan of Administration.

The following sections provide details on our 2012 fuel requirements, compared to 2011 BCF. All commodity prices which are purchased on a United States Dollar (USD) basis have been converted to Canadian Dollars (CAD) at an average exchange rate of $1.0089 CAD for each USD. The derivation of this exchange rate is described later in this section of the Application.

Solid Fuels Forecast Methodology

In developing the solid fuel budget for this Application, we followed the forecasting methodology outlined in the FAM POA. The pricing of uncommitted volumes is reflected in Figure 2.9.

Figure 2.9

Uncommitted Volumes				
Commodity	**Volume (MT)**	**Sulphur Content (Wt. %)**	**Heat Content (Btu/lbs)**	**Commodity (CAD $/MT FOB)**
Imports				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
*FOB Load Port				

The majority of our generation comes from four generating stations[3] fired by either coal or a blend of coal and petroleum coke. Coal may come from both domestic and imported sources, while petroleum coke is imported. The relationships of various fuel prices, in conjunction with their emissions and combustion characteristics, determine the mix of fuels. Figure 2.10 outlines the forecast mix of solid fuel blends for the 2011 BCF and 2012 GRA.

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

Figure 2.10

Mix of Solid Fuel Blends for Generation		
	2011 BCF	**2012 GRA**
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]

In 2012, import coal and petcoke account for 81 percent of NS Power's solid fuel requirements.

The quality of solid fuel available to us as a result of emissions restrictions also affects the price of fuel in our portfolio. Due to the change in mercury regulations announced in the latter half of 2010, we have introduced quantities of less expensive fuel sources in the blends at the generating stations.

Petroleum coke accounts for [redacted] of the 2012 solid fuel mix. The price of uncommitted volumes in 2012 is 28 percent higher than the combined contracted and uncommitted volumes in the 2011 BCF. Market escalation, as well as the expiry of a lower-priced contract at the end of 2011 is contributing to this difference. NS Power is taking steps to test alternate fuels for Point Aconi, to be ready for potential fuel switching away from petcoke.

As shown in Figure 2.11, the average cost of solid fuel is [redacted] per metric tonne in the 2012 GRA, [redacted] higher than the solid fuel cost in 2011 BCF.

Figure 2.11
REDACTED

[redacted]

<u>Natural Gas & Oil Methodology</u>

Natural Gas Forecast

With the market price of HFO forecast to be higher than that of natural gas in all months, we expect it to be economic to burn natural gas throughout 2012 in Units 1, 2 and 3 at Tufts Cove. We also anticipate natural gas to be economically dispatched in the General Electric LM6000 combustion turbines (Tufts Cove Units 4 and 5) as well as the new waste heat recovery unit (Tufts Cove Unit 6).

Figure 2.12 shows the cost of natural gas in the 2011 BCF versus the 2012 GRA. We forecast the average cost of natural gas consumed, including transportation charges to Tufts Cove, to be [redacted] delivered in 2012. This is [redacted] lower than the 2011 BCF.

Figure 2.12
REDACTED

[redacted]

Figure 2.13 shows the 2012 forward price curves for oil and for natural gas adjusted for delivery to Tufts Cove. As the graph indicates, natural gas prices are expected to remain below HFO prices throughout 2012.

Figure 2.13
REDACTED

[redacted]

We manage financial exposure to changes in the market price of HFO and natural gas through the use of swap and option contracts.[4]

The HFO and natural gas prices in this Application are produced using forward price curves and in-place hedges.[5] When reselling natural gas, the portion of market-price indexed (floating price) gas volumes available under the existing gas contract are sold at matching or similar indices for no material cost or benefit to us and our customers.

Oil Forecast

Heavy Fuel Oil

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 46 thousand barrels of HFO in 2012 as support fuel at our coal fired plants, compared to 44 thousand barrels in 2011 BCF.

[4] Swap and option contracts are financial instruments used to lower volatility in pricing terms for a supply contract.
[5] The term "forward price curve" refers to a graph of future prices decided upon by both buyer and seller for any given commodity.

Figure 2.14 shows HFO costs for the 2011 BCF versus the 2012 GRA. The forecast price is [redacted] or approximately [redacted] delivered. This is an increase of [redacted] in the unit price of HFO.

Figure 2.14

REDACTED

[redacted]

Light Fuel Oil

We expect to consume 2 million gallons of LFO in 2012 as start-up fuel in our thermal units and for operation of the oil-fired combustion turbines. The quantity of LFO forecast is slightly higher than the 2011 BCF consumption of 1.9 million gallons, reflecting projected higher peak demand requirements. Figure 2.15 shows LFO price for the 2011 BCF versus the 2012 GRA. The forecast price for LFO in 2012 is [redacted]. This is a [redacted] increase per MMBtu.

Figure 2.15
REDACTED

[redacted]

Renewable Energy

NS Power-Owned

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

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".[6] The use of this average, results in a 2012 production forecast of 975 GWh, which includes tidal energy at 27.4 GWh from the Annapolis Tidal Generating Station.

The Nuttby Mountain Wind Farm is forecast to produce 140 GWh, the Digby Wind Farm is forecast to produce 107 GWh and wind turbines located at Grand Étang and Little Brook are forecast to produce a total of 3.3 GWh in 2012. We also have a 49 percent stake in the Point Tupper Wind Farm, forecast to produce 58 GWh in 2012.

Independent Power Producer Contracts

Pre-2001

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 about 24 MW and provides approximately 170 GWh annually.[7]

Post-2001

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 85 GWh annually.

[6] NSPI 2002 Rate Case, UARB Decision, NSUARB – NSPI – P – 875, October 23, 2002, paragraph 91.
[7] A waste-burning generation contract ended with the closure of the [redacted] in 2005.

During the period from 2002 to 2008, NS Power executed PPAs with five wind developers, one biomass developer and one biogas developer.[8] Total generation from these post-2001 contracts is approximately 160 GWh annually.

Post-2008

Since 2008, we have entered into PPAs for an additional 218 MW of renewable energy sourced from wind. Of the 218 MW, 193 MW will come from five transmission connected projects. The remaining 25 MW will come from smaller distribution connected projects. By the end of 2009, the 51 MW facility at Dalhousie Mountain was operational. By the end of 2010, the 50 MW facility at Nuttby Mountain and the 30 MW facility at Digby Neck, both acquired by NS Power, and a 6 MW facility at Maryvale, and a 22 MW facility at Point Tupper all became operational. NS Power expects the 62 MW facility at Glen Dhu will be fully operational by the end of June 2011, with the smaller projects coming online by mid-2012. Total generation from these post-2008 contracts totals approximately 470 GWh annually.

Renewable Electricity

The additional procurement of 218 MW since 2008 was largely driven by the Provincial renewable energy requirements. In 2004, the Nova Scotia Government passed new legislation outlining renewable energy requirements going forward.[9] The Renewable Electricity Regulations create a Renewable Energy Standard (RES) which requires, by 2011, that NS Power produce five percent of its energy from renewable resources constructed after 2001. NS Power forecasts this to be approximately 600 GWh in 2011. By 2013, this target is increased to 10 percent or approximately 1,200 GWh annually.

[8] 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.
[9] The Renewable Electricity Regulations, made under Section 5 of the *Electricity Act*, S.N.S. 2004, c.25.

The post-2008 PPAs, combined with the existing post-2001 renewable resources from IPPs, and the flexibility to address shortfalls provided in the revised RES regulations will allow compliance with the 2011 RES requirement. Please refer to Appendix A for NS Power's RES compliance plan.

Tidal Energy

NS Power has partnered with OpenHydro to explore a new source of tidal energy for Nova Scotia and, as part of a test, deployed an in-stream tidal turbine in the Bay of Fundy in 2009. Following the discovery that tidal turbine blades were missing, our turbine was successfully recovered in December, 2010. Data analysis and physical investigative work will inform redesign and future deployment plans.

Load Forecast

As described in previous sections, the increase in fuel expenses for 2012 is partially a function of changes in commodity prices and purchased power. Changes in load are also projected to increase fuel expense in 2012.

The 2012 total load is forecast to be 12,682 GWh, including exports versus 12,574 GWh in the 2011 BCF. As noted in the load forecast section of this Application, in-province load is higher than forecast for the 2011 BCF, but exports are lower.

The 2012 fuel cost increase due to higher in-province energy consumption is also influenced by an increase in the peak demand requirement. In general, as the demand increases, higher cost fuels are called on to serve the highest demand, or "marginal"[10] load.

We expect to export a small amount of energy in 2012. These 2012 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 8.

US Dollar Requirements and Foreign Exchange Rates

Most of our fuel requirement is purchased in United States Dollars. The imported coal, petroleum coke, heavy fuel oil, natural gas and ocean freight 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.

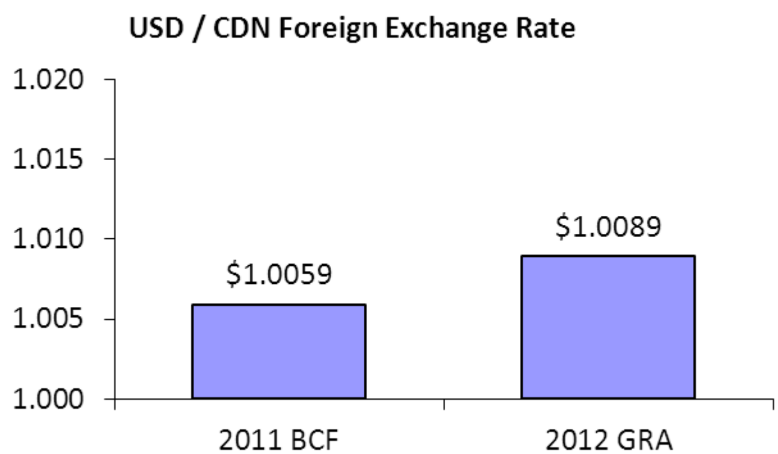
We hedge our USD requirements based on known and forecast requirements. Our guidelines are to hedge 30 – 50 percent of the three forward years. For the current 12-month period, a maximum of 30 percent of the forecast USD requirement would remain open to allow for changes in the cash flow timing and volume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

[10] Marginal refers to the next MWh that would need to be produced. The marginal cost is the cost that would be incurred to produce that next MWh.

Through our purchase of forward foreign exchange contracts, we have 47 percent of our 2012 USD requirement at an average rate of 0.9960 and have forecast a blended rate of 1.0089 on all fuel costs in this Application.

Figure 2.16



2.2.4 Summary

The 2011 BCF included provisions for fuel and purchased power expenses of $537.8 million. Our net fuel costs for 2012 are forecasted to be $573.9 million, $36.1 million higher than the 2011 BCF.

The components of the changes in 2012 fuel costs over the 2011 BCF are:

- an increase in the commodity and transportation cost of solid fuel; partially offset by savings associated with natural gas, equating to $18 million
- higher total load resulting in net increases to fuel expense of $17 million

- higher prices and quantities of purchased power resulting in an increase of $16 million
- lower export generation resulting in a decrease of $8 million
- other items including changes in mercury capture additives, LFO and HFO resulting in decreased fuel costs of $7 million

On July 22, 2010, the Nova Scotia government announced that it would change its mercury regulations to better align with provincially regulated reductions for nitrogen oxides, sulphur dioxide, and carbon dioxide and compliance with Provincial renewable electricity regulations. Since the introduction of this change, NS Power has been able to partly offset increased solid fuel costs through the use of lower cost coals. Nova Scotia Power has also been positioned to take advantage of changing market conditions – specifically reductions in natural gas prices.

Our Fuel and Risk Management group considers the advice of industry experts to support procurement strategy and execution.

Emily Medine of Energy Ventures Analysis provides expert solid fuel procurement advice to NS Power. We also retain the expertise of Leonard Crook of ICF International for advice on natural gas procurement. At this time, we are not presenting evidence from these experts since the BCF reset is prescribed by the FAM POA. However, each of these experts is available to assist the Board in its deliberations, including by filing expert evidence, in reply to matters that may be in issue at the time of the Hearing.

3.0 FUEL ADJUSTMENT MECHANISM

3.1 Overview

In 2009, the UARB recognized the impact of volatile fuel prices by approving a Fuel Adjustment Mechanism. The FAM adjusts the price of electricity at the start of each year to reflect changes in fuel costs and fuel cost recovery. The FAM Plan of Administration prescribes the method for calculating the fuel costs on which rates are based. It establishes a Base Cost of Fuel, which is a projection of fuel costs expected in the 2012 test year. It also prescribes a set of adjustments once actual fuel costs are known.

The FAM resets the Base Cost of Fuel every two years, and during a General Rate Application such as this one. The UARB last approved a reset of the BCF in November 2010, based on projected fuel costs for 2011. Since then, fuel costs have remained volatile, and solid fuel costs have continued to rise.

Section 2 of this Application sets forth our proposals for resetting the 2012 Base Cost of Fuel. This section deals with the mechanics of resetting the BCF while simultaneously considering a GRA.

The FAM includes an incentive component to give Nova Scotia Power a direct financial interest in managing fuel costs effectively. Under this provision, Nova Scotia Power retains or absorbs 10 percent of any over- or under-recovered amount, less the difference between the incentive threshold and the base fuel cost, to a maximum of $5 million. Nova Scotia Power has incurred a future income tax expense related to the fuel adjustment, based on our applicable statutory income tax rate. In accordance with approved accounting policies, Nova Scotia Power treats the FAM balance as a regulatory asset or liability, as future rates will be adjusted to provide recovery from (or a refund to) customers in the following year.

3.2 Relationship between the FAM and this General Rate Application

We have filed this Application for a general rate increase to recover the increased costs of service for the test year beginning January 1, 2012.

Under the FAM framework, base fuel costs are reset every two years and as part of a GRA. Overall fuel costs have continued to rise since the 2011 base fuel cost reset. Accordingly, we have included forecast increases in fuel costs for 2012 as part of this Application for 2012 rates.

This approach enables the Board to consider all evidence relevant to both the BCF and the 2012 revenue requirement. The Board can establish the Base Cost of Fuel amount for the FAM for 2012, using the fuel forecast information evidence in this Proceeding. The amount to be included in rates for fuel and purchased power expense can be incorporated into new rates effective January 1, 2012 to ensure recovery of the test year revenue requirement.

The FAM requires Nova Scotia Power to prepare a fuel forecast each year over the summer, and to file it no later than August 31. NS Power will file an updated fuel Standardized Filing for this GRA Application no later than August 31. This will also satisfy the update requirements for FAM process.

Preparation and implementation of the FAM, which includes a regular cycle of detailed reporting, will continue in parallel with this proceeding. The next subsequent adjustment to the Base Cost for Fuel would occur either as part of a future GRA, or on the two-year cycle set forth in the FAM base fuel adjustment mechanism, whichever comes first. The FAM process includes an annual actual adjustment (AA) and a balance adjustment (BA), both of which will be set on the usual FAM schedule in November of this year, to be effective on January 1, 2012. Therefore, this Application does not include the AA and BA calculations.

NS Power's portion of the Point Tupper Wind Farm operating costs are currently recovered through the FAM, per the Board's letter of December 21, 2010.[11] NS Power is requesting that its portion of the Point Tupper Wind Farm's OM&G, financing and depreciation costs, now recovered through the FAM, be recovered through our non-fuel rate components effective for the 2012 test year. This would be consistent with how we recover the operating costs of other NS Power owned wind projects. This Application reflects this new treatment.

[11] NSUARB Letter to NSPI – Point Tupper Wind Project – Request Approval of Accounting Methodology through Fuel Adjustment Mechanism, NSUARB-NSPI-P128.10, December 21, 2010.

4.0 DEPRECIATION AND REGULATORY AMORTIZATION

4.1 Overview

This section outlines depreciation and regulatory amortization expenses NS Power seeks to recover through 2012 customer rates.

- We have based the depreciation expense on depreciation rates established through the recent settlement agreement signed by stakeholders and presented to the UARB for approval in April 2011,[12] and on net additions to property, plant, and equipment since rates were last set in 2009.

- The UARB has previously approved the regulatory amortization expense we seek to include in the 2012 revenue requirement with the exception of vegetation management. These expenses are properly recovered in customer rates. We ask that recovery of these previously deferred expenses continue in 2012. This section covers the following:
    - Tax regulatory amortization
    - Demand Side Management (DSM) regulatory amortization
    - Vegetation management amortization

At the time of preparing this Application, the Board was considering the depreciation settlement agreement, which has the agreement and support of all customer classes. Nova Scotia Power has based its test year assumptions on the settlement agreement as the most reasonable information available.

[12] NSPI Letter to NSUARB – Approval of Depreciation Rates, Minutes of Settlement, NSUARB-NSPI-P-891, April 18, 2011.

From 2009 Compliance to 2012, depreciation expenses will increase by $33.0 million to $178.0 million. To calculate this expense, we used the depreciation rates in the 2011 Depreciation Study Settlement Agreement. The total increase reflects net additions to property, plant, and equipment since electricity rates were last set.

For the 2012 test year, regulatory amortization expense will increase by $3.3 million to $21.6 million over 2009 Compliance. This reflects a levelized revenue requirement approach for taxes, and a straight line approach for Demand Side Management and vegetation management.

4.2 2010 Depreciation Study

NS Power is required to review and update its depreciation rates on a regular basis. Early in 2010, NS Power engaged Gannett Fleming to conduct a depreciation study based on 2009 year-end balances. We filed this study with the Board in October 2010. In April, we reached a settlement agreement with stakeholders that has been filed with the UARB, for approval.

The revenue requirement set out in this Application reflects the rates requested in the 2011 Depreciation Study Settlement Agreement. Implementation of these new depreciation rates has no material effect on depreciation expense for the 2012 test year.

4.3 Additions to Plant

Depreciation expenses will increase by $33.0 million as a result of capital additions to plant in service filed as part of the approved Annual Capital Expenditure (ACE) Programs and other capital expenditures approved by the Board. The total depreciable plant balance used in the 2012 test year has increased by about $990 million over 2009

Compliance, due to in-service additions filed through the ACE Program for 2010 and forecasted 2011 and 2012.

Since rates were last set in 2009, a number of major projects have gone into service. This has improved our environmental performance and company operations to the benefit of customers. The projects include:

- Digby Wind – $80 million
- Nuttby Wind – $120 million
- Point Tupper Wind – $26 million
- Work Management System – $16 million

Nova Scotia Power's forecasted capital spending for 2011 and 2012 (including work in progress) includes more major multi-year projects that will contribute to NS Power's reliability, air emissions reductions, and fuel cost savings:

- Tufts Cove 6 Combined cycle
- NewPage Biomass Project
- Light Emitting Diode (LED) street lighting replacement
- Baghouse additions
- Additional wind turbines
- Advanced Metering Infrastructure
- Transmission additions and system reliability improvements
- Transmission upgrades that enable increased use of renewable energy and benefit customers by reducing the overall cost of compliance with provincial greenhouse gas (GHG) regulations.

4.4 Regulatory Amortizations

Regulatory amortizations are $21.6 million in 2012, an increase of $3.3 million over 2009 Compliance per Figure 4.1.

Figure 4.1

Amortizations	2009C ($M)	2012 ($M)
Section 21	$14.3	$16.2
2005 Q1 tax	1.8	2.2
DSM	2.2	2.2
Vegetation Management	-	1.0
Total	**$18.3**	**$21.6**

Figure 4.1 reflects:

- An increase of $1.9 million related to Section 21 taxes using an eight year levelized approach approved by the UARB in its 2005 Rate Decision.[13] The schedule approved by the UARB in its 2009 Rate Decision[14] was adjusted as reflected in Figure 4.2 below.

- An increase of $0.4 million of amortization that relates to the deferral of income taxes applicable to Q1, 2005. The amortization schedule was developed using an eight year levelized approach as approved by the UARB in its 2009 Rate Decision.

- An increase of $1.0 million of amortization relating to the amortization of the deferred vegetation management expenses.

[13] NSPI 2005 Rate Case, UARB Decision, NSUARB-NSPI-P-881, March 31, 2005, paragraph 328.
[14] NSPI 2009 Rate Case, UARB Decision, NSUARB-NSPI-P-888, November 5, 2008.

Section 21 Amortization

The Section 21 amortization approved by the UARB through the 2009 Compliance Filing reflects an adjusted schedule for a pre-2003 tax and interest recovery amount received in 2009.

During 2009, Nova Scotia Power received a tax recovery of $5.5 million from Manufacturing and Processing tax credits from 1999-2002. This recovery reduced the Section 21 regulatory asset.

On December 31, 2009 we reduced the Section 21 regulatory assets by $0.5 million as agreed in the 2009 Return on Equity (ROE) settlement approved by the UARB.[15] NS Power reached an agreement with stakeholders on its calculation methodology used for regulated ROE. Under this agreement, Nova Scotia Power will continue to use actual capital structure, actual equity, and actual net earnings to calculate actual annual regulated ROE. The agreement gives NS Power flexibility in amortizing the pre-2003 income tax regulatory asset, allowing NS Power to recognize additional amortization amounts in current periods, and reducing amounts in future periods. As a result, effective December 31, 2009, Nova Scotia Power recognized an additional discretionary $10 million of regulatory amortization expense ($4.5 million of AAA and $5.5 million of AAA-2). Effective December 31, 2010, we recognized an additional $4.8 million ($10.3 million of AAA and ($5.5) million of AAA-2) to allow flexibility relating to future customer rate requirements. The UARB approved the agreement. NS Power will record the $14.8 million deferral in 2011 to offset the required amortization of Section 21 during 2011. As a result, as of December 31, 2011 there will be no deferrals or carryover of Section 21 expense remaining.

[15] NSUARB-NSPI-P-888(2) – Calculation of Nova Scotia Power Inc’s Return on Equity.

Figure 4.2 shows the reconciliation of the Section 21 tax regulatory asset.

Figure 4.2

Section 21 Taxes	**$M**
January 1, 2009	**105.3**
2009 amortization	(14.1)
Adjustment pertaining to M&P tax credit 1999-2002	(5.5)
Adjustment resulting from 2009 ROE settlement	(0.5)
2009 discretionary amortization per 2009 ROE settlement	(10.0)
December 31, 2009 balance	**$75.2**
2010 amortization	(13.5)
2010 discretionary amortization per 2009 ROE settlement	(4.8)
December 31, 2010 balance	**$56.9**
2011 amortization	(14.8)
2010 discretionary amortization per 2009 ROE settlement	14.8
December 31, 2011 balance	**$56.9**

The December 31, 2011 balance compared favourably to the amortization schedule established in the 2009 GRA, which forecasted the balance on December 31, 2011 to be $60.7 million. Figure 4.3 shows the amortization schedule based on the new Section 21 deferred balance.

Figure 4.3

Year	**Amortization ($M)**	**Tax Effect of Amortization ($M)**	**Carrying Cost ($M)**	**Total ($M)**
2012	16.2	7.3	4.7	28.2
2013	17.3	7.8	3.1	28.2
2014	18.5	8.3	1.4	28.2
2015	4.8	2.2	0.1	7.0

Included in the 2012 revenue requirement is $16.2 million of amortization related to Section 21 resulting in an increase of $1.9 million over 2009 Compliance. The estimated amortization for 2012 in the schedule approved in the 2009 GRA was $17.3 million resulting in the new schedule above with amortization being $1.1 million lower. The total cost of $28.2 million is held constant through the amortization period in accordance with the levelized revenue requirement directed by the UARB.

2005 Q1 Tax Amortization

The 2005 taxes included an amortization of $2.2 million in 2012 as shown in Figure 4.5. The total cost of $3.9 million remains constant for the recovery amortization period in accord with the levelized revenue requirement approach approved by the UARB in the 2007 Rate Decision.

Figure 4.4 shows the reconciliation pertaining to 2005 Q1 Tax Amortization.

Figure 4.4

Q1 2005 Tax Amortization	**$M**
Balance, January 1, 2011	10.0
2009 amortization based on UARB approved schedule	(2.1)
December 31, 2011 balance	**$7.9**

Accordingly, we have included $2.2 million of amortization of the 2005 Q1 deferred taxes in the 2012 revenue requirement. This results in a $0.4 million increase over 2009 Compliance.

Figure 4.5

Year	Amortization ($M)	Tax Effect of Amortization ($M)	Carrying Cost ($M)	Total ($M)
2012	2.2	1.0	0.6	3.9
2013	2.4	1.1	0.4	3.9
2014	2.6	1.1	0.2	3.9
2015	0.7	0.3	0.0	1.0

<u>Demand Side Management Amortization</u>

In the 2009 Rate Decision, the Board approved the amortization of DSM expenditures for 2008 and 2009 over six years starting in 2009. These programs help customers manage their electricity consumption and help participants lower their total energy spending.

The 2012 revenue requirement includes an annual amortization amount of $2.2 million reflecting the deferred DSM expenditure. This results in no change in amounts included in 2009 Compliance.

<u>2008 Vegetation Management</u>

As stated in NS Power's correspondence to the UARB in February 15, 2008:

> …investments in vegetation management need to be a priority, in order to improve reliability for customers. We can and want to meet the expectation of our customers regarding enhanced reliability.[16]

[16] NSPI Letter to NSUARB - Distribution System Vegetation Management - P.401.32, February 15, 2008, paragraph 5.

In February 2008, NS Power asked to spend an additional $2 million on vegetation management on the distribution system. The UARB approved this request in its March 2008 letter to NS Power:

> …the Board approves the additional $2 million spending in 2008 on the basis that it is both appropriate and justifiable. The Board also approves the deferral of this expenditure, including the recovery period, subject to review at the next rate hearing.[17]

We are proposing to start amortization in 2012 using a two year amortization of the approved $2 million spending. Thus the 2012 revenue requirement includes an annual increase of $1.0 million for the amortization of 2008 vegetation management expenses.

[17] NSUARB Letter to NSPI - Power Outage Review Decision - Distribution System Vegetation Management - P-401.32, March 12, 2008, paragraph 6.

5.0 OPERATING, MAINTENANCE & GENERAL

5.1 Overview

Electricity can seem like the simplest thing in the world: enter a darkened space, flip a switch, and light floods the room. But the apparent simplicity is deceptive. Behind the act of turning on a light lies a vast interconnecting complex of thermal power stations, hydro stations, gas turbines, transmission lines, control systems, pollution abatement equipment – and more than 1800 employees, including system maintenance crews, customer service staff, fuel buyers, engineers, technicians, and meter readers and more.

In NS Power's case, the system is not only complex, it is in the throes of major change as we move from coal generation to cleaner, more local, secure, and renewable sources of electricity. This process of change has been mandated by government as being in the best interests of our customers. Nova Scotia Power is proud to be the instrument of this change.

Carrying out such a big change is challenging. We do not have the luxury of shutting down operations while we reconfigure the way we produce power. Our position is akin to that of a family who must keep living in their home while carrying out major renovations.

Some of the OM&G costs outlined in this Application reflect necessary activities in support of the changes unfolding in our generation system. Others reflect our need to recruit and retain outstanding employees who bring an ethic of hard work, skill, and dedication to many diverse and difficult tasks. We are extremely proud of the men and women who produce and deliver electricity to Nova Scotians.

We also recognize that power bills can represent a significant cost to families and businesses in Nova Scotia, and this makes OM&G costs a matter of keen interest to intervenors. We take our responsibility to control costs seriously, and we look forward to suggestions that the Board may have to help us carry out that responsibility efficiently while maintaining a robust and reliable power utility based on cleaner, local, more secure energy sources.

NS Power's OM&G expenses fall broadly into three areas:

1. Operating and maintaining our generation, transmission, and distribution facilities;
2. Delivering service to customers; and
3. Providing corporate support to those functions.

We forecast our 2012 OM&G expenses at $248.5 million, representing approximately 18 percent of the 2012 revenue requirement. The forecast increase for 2012 compared to the 2009 Compliance Filing (2009C) is $31.8 million. NS Power did not file a General Rate Application for 2010 or 2011 and therefore the OM&G request for 2012 reflects a three year increase in costs. Included in the 2012 OM&G request are additional investments in reliability, storm response and OM&G associated with the operation of three new wind projects (Digby, Nuttby and Point Tupper) that went in service at the end of 2010. These three initiatives total 40 percent or $12.5 million of the $31.8 million increase in OM&G. The remaining amount represents a compound annual escalation of less than 3 percent per year, which includes an $11.5 million increase in pension expense, based on factors largely outside NS Power's control.

The OM&G increases we seek in this Application focus on improving reliability, improving service levels and increasing renewable energy. These are improvements sought by customers.

Comprehensive reviews of NS Power's OM&G expenses show us to be a well-managed utility. Among competing companies, we stand at about the 50th percentile for non-union salaries. Our collective agreement with the International Brotherhood of Electrical Workers (IBEW) runs to 2012.

Labour costs account for most of the OM&G increase forecast in this Application. These costs represent an investment in our core business areas: power production and customer service. Our technical and construction services division underwent necessary expansion to meet provincial environmental obligations and preparing for succession planning. These investments in skilled labour ensures knowledge transfer from an experienced workforce, enables transformation and expansion to cleaner energy resources, and keeps NS Power competitive in its recruitment of skilled labour.

Figure 5.1 summarizes the components of the increase.

Figure 5.1

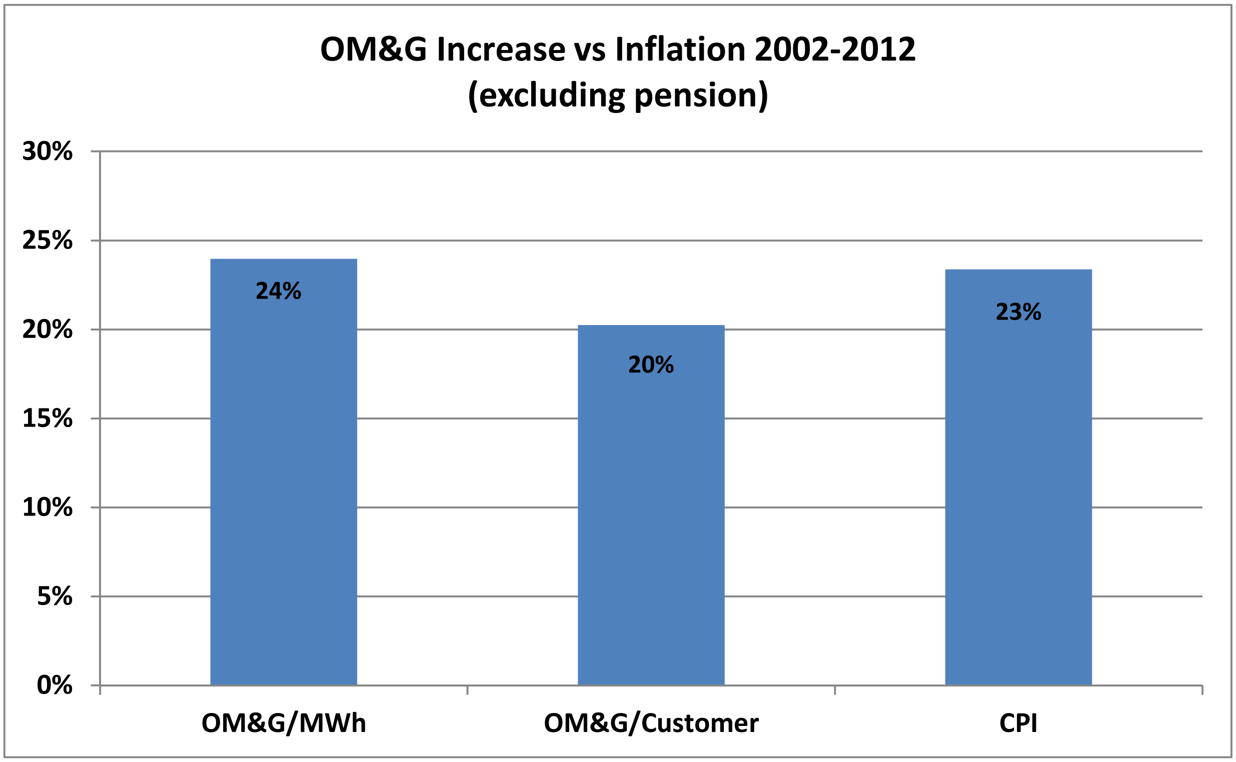
OM&G Cost Driver	**$M**
Labour costs (1)	9.1
Vegetation management	3.4
Storm response	3.7
Renewable project operating costs	5.4
Pension expense	11.5
Other	(1.3)
Total change to OM&G	**$31.8**

(1) Note: Labour costs are net of administrative overhead, corporate allocations and include wage increases for both union and non-union groups, succession planning, a portion of pension, succession planning and regulatory requirements offset by an increase in the administrative overhead credit for labour on capital projects.

NS Power will soon be at the most challenging phase of the fuel transformation. We have built, and contracted for, extra capacity to meet the Renewable Energy Standards and greenhouse gas reduction targets, but it is too early to close down facilities the new renewable generation capacity will render redundant. The existing solid fuel plants will begin to experience lower levels of utilization in the transition period. This unfortunately will serve to increase the cost per unit of output. As a result, we can predict in the medium term higher costs due to capacity additions at the same time as higher unit costs on the legacy fleet. NS Power is doing everything possible to manage costs through this period. Lower fuel bills will help mitigate this situation. Our comprehensive approach to generation planning will help us find the best approach to managing our capacity in these challenging circumstances. We recognize that a single-minded focus on OM&G savings could result in higher fuel costs to customers, and will not jeopardize generation efficiencies to achieve operating cost reductions. In the coming years we expect to experience a higher than desirable cost structure because of the extra capacity required while making the transition to a clearer fuel mix.

NS Power has effectively controlled its OM&G costs. Figure 5.2 below demonstrates that on a per customer basis, NS Power's requested OM&G spending for 2012 is less than the Consumer Price Index (CPI) increase over the same period. OM&G spending per MWh is slightly higher than CPI as load growth has been slowed due to conservation and efficiency programs and an economic recession.

Figure 5.2



Recent General Rate Applications, and various reviews by the UARB, have given customers a provision of transparency and details about NS Power's OM&G costs.

Examples include:

- In each rate application, we have provided a trend analysis that includes costs per megawatt hour and per customer. We also produce a line-by-line analysis of OM&G costs with variance explanations across all divisions.

- In June 2003 and September 2005, we filed internal OM&G studies. In 2006 we commissioned Accenture Inc. to review OM&G expenditures. We filed

Accenture's report in January 2007, at which point it became subject to stakeholder review.

- We filed expert reports about NS Power's pension expenses with the Board, and these were examined during UARB proceedings.

- The Board's consultants have completed reviews of NS Power's operating and maintenance practices for transmission and distribution.

- The Board's consultants have reviewed our customer communications processes.

- We filed an analysis of our vegetation management practices and spending levels, which the Board's consultant subsequently endorsed.

- We have given the Board and intervenors access to our collective agreement with the International Brotherhood of Electrical Workers.

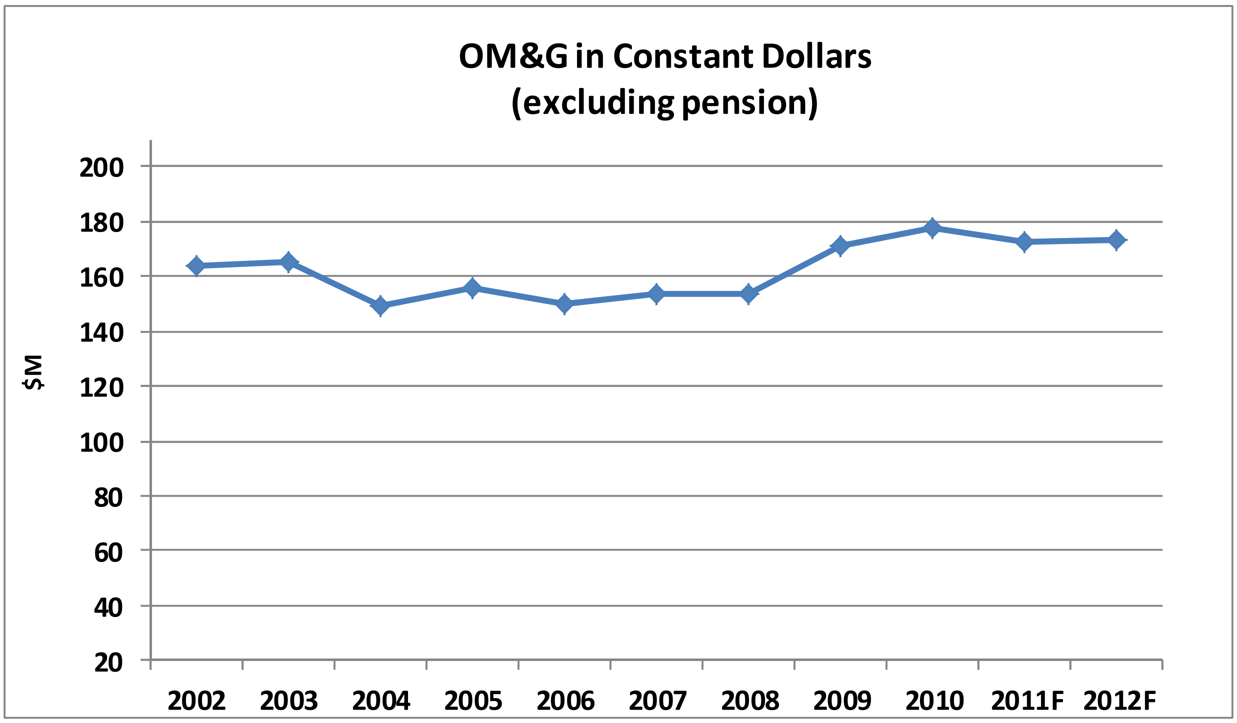
- The Board's consultants have audited our affiliate transactions.

- The Board engaged consultants to review OM&G expenses for power production, customer operations, customer service, regulatory affairs, and executive compensation. As with the foregoing initiatives, NS Power provided its full support to this review.

- The Liberty FAM 2010 audit included a review of plant operations that showed plants were generally well run and well maintained compared to similar plants in other jurisdictions.

Through effective cost control mechanisms we have stabilized OM&G expenditures in constant dollars since 2002 even with the investment in storm-related outage response and vegetation management as outlined in the following chart.

Figure 5.3



The stabilization of constant dollar OM&G is a significant achievement considering that over the same period:

- our generation output has increased by 5.4 percent
- our average number of customers increased by 8.7 percent
- environmental management costs have increased
- we have implemented succession planning initiatives
- we have added new gas turbines, and renewable energy investments

Our record of effective OM&G cost control, confirmed by various independent reviews, provides a basis for assessing the increased OM&G spending proposed in this Application.

We have updated OM&G utility benchmarking metrics to better illustrate our position and trending relative to our industry peers. As depicted in Appendix B, we continue to perform well and have demonstrated more favourable trending results alongside our peers that have experienced similar challenges with increased labour costs resulting from increase maintenance hours from aging assets, maturing workforce with apprentice programs, and a competitive labour market.

The following sections discuss NS Power's requested OM&G increase for the 2012 test year.

5.2 Labour Related Increases (Net of Administrative Overhead Related to Capital Projects)

The increase in OM&G from 2009 Compliance results largely from increased labour costs. The increase mainly reflects market pressures on salaries resulting from an increasingly competitive labour market. Labour-related increases include wage increases for both union and non-union employees, succession planning, and regulatory requirements.

NS Power's compensation policy is to aim for pay rates approximating the 50th percentile of comparable non-union positions. We strive to pay non-union employees a salary in the middle of the range offered at other utilities. We negotiate union wages with IBEW Local 1928 through a collective bargaining process.

Our 56 month collective agreement with the IBEW expires in March 2012. This agreement recognized the increased competition for skilled trades, and in particular the challenge of attracting and retaining Power Line Technicians and Power Engineers (formerly steam plant operators). The agreement established wage differentiation between skilled trades and other job classifications. This enables the company to offer competitive wage rates to attract and retain specific skilled trades that are key to our business, without providing "across-the-board" increases to all union job classifications.

Increases in union and non-union wages between 2009 Compliance and 2012 account for an increase in OM&G expense of $12.3 million, excluding pension. This accounts for three years of increases and equates to a 3.2 percent compounded annual increase each year since 2009C. The remainder of the increase in labour-related costs of $5.0 million primarily reflects succession planning initiatives, such as the addition of power engineers and apprentices.

The increase in capital investments results in an $8.2 million increase in our Administrative Overhead (AO) credit in 2012. AO is an amount credited to OM&G based on labour hours charged to capital projects and reduces our total OM&G costs. The AO rates are set during the Annual Capital Expenditure plan process. This credit reduced the labour-related expense increase in 2012 compared to 2009C by $8.2 million.

5.3 Pension Costs

Our pension expense for 2012 has increased by $11.5 million compared to 2009C. Pension expenses are forecast at $40.8 million in 2012, compared to $29.3 million in 2009C. In the 2009 General Rate Application, NS Power's pension expense of $29.3 million was based on a discount rate of 5.75 percent, and an assumed rate of return of 7.25 percent per year. The 5.75 percent discount rate assumption was based on the December 31, 2007 discount rate, which was the "measurement date" used for the 2009

Compliance Filing. For the 2012 General Rate Application, the pension expense amount of $40.8 million in this Application is based on a discount rate of 5.5 percent and an assumed rate of return of 7.0 percent per year. The 5.5 percent discount rate assumption is based on the December 31, 2010, discount rate, which is the “measurement date” for the 2012 Compliance Filing.

Four main factors drive the $11.5 million increase in pension expense:

- A $7.2 million increase in the amount of net actuarial losses being amortized (or recognized) into pension expense. Under pension accounting standards, actuarial gains and losses arise each year from investment returns which differ from the assumptions, and updated measurements of actuarial obligations which differ from the projected obligation. These gains and losses are not recognized immediately; they are amortized into pension expense over future years. At the time of preparing the 2009 Compliance Filing (early 2008), we assumed that the asset return for 2008 would be 7.50 percent. In fact, 2008 was one of the worst years for investment performance in history and like the vast majority of Canadian pension plans, the NS Power pension plans had a double digit negative return. Part of this actuarial loss is recognized in the projected 2012 pension expense.

- A decrease of 25 basis points in the assumed discount rate, which increases pension expense by about $3.5 million. The discount rate used to determine pension expense is based on high quality corporate bonds with the same duration as the obligations. The duration of NS Power’s obligations is approximately 14 years. The discount rate of 5.5 percent is based on high quality bonds at the time of preparing this Application, as provided by NS Power's actuarial consultant, Morneau Sobeco. Under Generally Accepted Accounting Principles (GAAP), organizations are required to use the discount rate at the end of the fiscal year (December 31 in NS Power's case) to determine the upcoming year's pension expense. Thus, NS Power does not influence the discount rate used to determine pension expense.

- A reduction of 25 basis points in the assumed rate of return on plan assets which increases pension expense by about $1.9 million. NS Power management has also reviewed the assumed long-term return on asset assumption. As part of this review, management also took into consideration the return assumption used by other Canadian organizations for pension plan accounting purposes. After careful consideration, and taking into account the Plan's 65 percent equity and 35 percent fixed income asset mix, management reduced the assumed rate of return on plan assets from 7.25 percent to 7.00 percent effective January 1, 2011.

- The elimination of the amortization of the net transitional obligation as a result of moving from Canadian GAAP to US GAAP for reporting purposes resulting in a $2.3 million decrease in pension expense. Effective January 1, 2011 (with restatement to January 1, 2009), NS Power reports under US GAAP. Under US GAAP, the rules for determining pension expense are materially the same as under Canadian GAAP. As a result of the transition, there was a one-time recognition of the unamortized net transitional obligation onto the balance sheet. As a result, there is no requirement to amortize the net transitional obligation into 2012 pension expense as there was in 2009.

The remaining $1.2 million increase results from several other factors, including changes in demographics, plan experience, and an update to the assumed mortality table to reflect the fact that Canadians on average, are living longer.

5.4 OM&G Costs by Group

OM&G cost changes among the operating groups of Power Production, Customer Operations, Customer Service, Technical & Construction Services, the Corporate Support Groups and Corporate Adjustments are discussed in this section.

A comparison of annual expenditures for 2009C, 2009C restated, 2010A, 2011F and 2012F is provided in an OM&G Detailed Variance Analysis, which is included as Appendix C.

The OM&G requirement in the 2009 Compliance Filing reflects expenses included in rates under the 2009 GRA Settlement Agreement approved by the UARB. Since general rates were last set, NS Power restructured and underwent an expansion of its Technical and Construction Services group to meet environmental obligations, succession planning and reliability investments. Strong succession planning for highly specialized technical resources is critical for a utility providing an essential service. NS Power also developed a Sustainability Group. This investment in skilled labour ensures knowledge transfer from an experienced workforce enables transformation and expansion to cleaner energy resources and keeps NS Power competitive in its recruitment from a national labour pool. Based on this, NS Power restated 2009 Compliance numbers for this reorganization so that comparisons year-over-year are more consistent (2009C restated).

The 2011 forecast represents NS Power's operating budget for the period (2011F). The 2012 forecast reflects the Company's estimate for the test year at the time of filing (2012F).

Operating group costs accounts for about 91 percent of OM&G spending. Corporate Support group and Corporate Adjustment costs are approximately 9 percent of the total.

5.4.1 Power Production

Power Production OM&G includes costs required to operate and maintain the generation fleet and costs associated with fuel procurement, FAM administration and management.

Power Production accounts for about 42 percent of total OM&G expenses forecast for 2012. In 2012 these costs increase by $18.2 million over 2009C, an increase of 21 percent for the three year period. Power Production OM&G expense for 2009C restated to 2012 is summarized in Figure 5.4.

Figure 5.4

Power Production ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
85.6	90.9		103.9

Approximately one third of the increase in 2012 results from the addition of the three wind projects, Point Tupper, Nuttby Mountain and Digby with forecasted operating costs of $5.4 million in 2012. Figure 5.5 lists the major components of the 2012 cost increase of $18.3 million over 2009C.

Figure 5.5

Cost	**Amount ($M)**
Union and non-union labour	5.6
Additional Labour	1.5
Operating costs of three new wind projects	5.4
Pension	4.2
Legal costs	1.4
Operating costs of TUC6	0.5
Mercury monitoring program	0.4
NERC-CIP and security	0.3
In-stream Hydro	0.3
Solid Fuel Handling Costs moved to FAM	(2.2)
Other	0.9
Total	**$18.3**

NS Power operates some of the most reliable electrical generating units in Canada. Generating units at the Point Tupper, Lingan and Tufts Cove power plants scored among the tops in their classes in an annual review by the Canadian Electricity Association (CEA) in 2007, 2008 and 2009.

The CEA report analyzed data from 2009, and included results for 80 fossil units and 29 combustion units. Copies of the ranking charts are attached in Appendix D.

Power Production personnel, in conjunction with Procurement, manage labour, materials and contract costs. Power Production has increased maintenance labour to complete repairs and rebuilds to avoid more expensive part replacements. Power Production staff also work with Procurement in the use of competitive tenders or negotiations of terms with vendors to help control the effect of raw material cost changes.

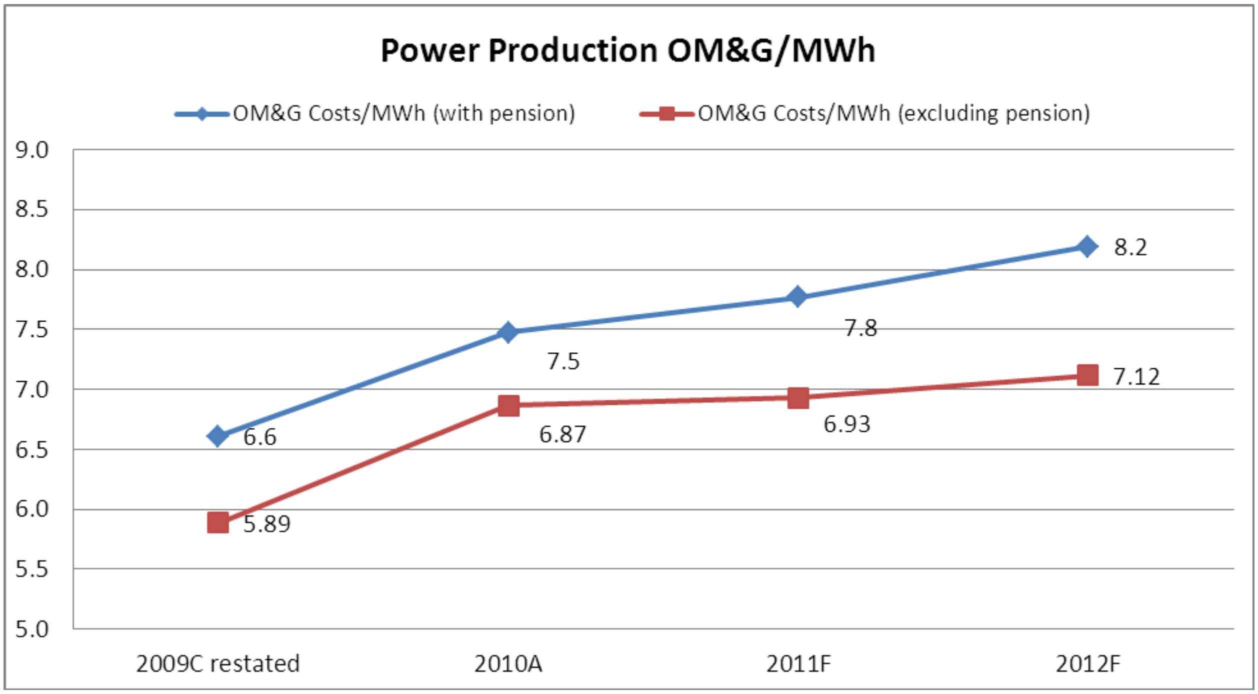
We are developing a work and asset management strategy that will allow the Power Production division to meet the challenges of aging infrastructure and experienced work force attrition, while sustaining operational performance, and meeting increasingly more challenging environmental regulations. It will provide a foundation from which to monitor the generation assets and optimize their maintenance and performance, as NS Power transitions to a cleaner greener future.

With respect to labour cost management, Power Production has focused on the further development of a cost-effective flexible workforce. NS Power's full-time staff includes multi-skilled workers and is augmented by term labour from NS Power's labour pool and contract workers as required to meet maintenance schedules.

Nova Scotia Power continues to focus on succession planning initiatives, inclusive of apprenticeship programs, designed to ensure qualified employees are attracted and retained to continually provide high quality plant performance. Strong succession planning is critical for a utility providing an essential service.

Figure 5.6 shows the Power Production OM&G costs per MWh from 2009C restated to 2012.

Figure 5.6



The increase in costs per MWh is primarily due to the lower load, additional OM&G associated with the three new wind projects and labour costs.

5.4.2 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 29 percent of the total OM&G expenses forecast for 2012. As shown in Figure 5.7, in 2012 these costs will increase by $9.2 million over

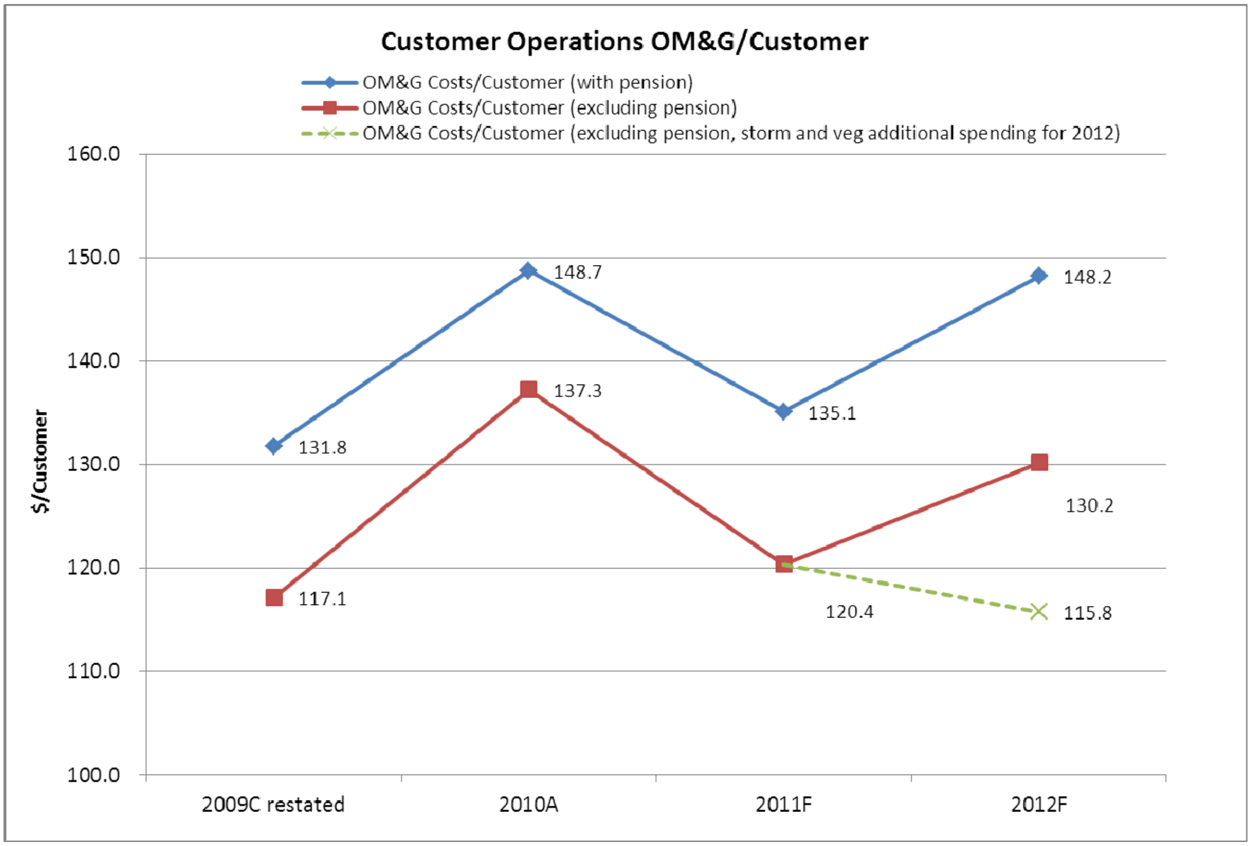
2009C restated, an increase of 14 percent. Increased vegetation management and storm costs make up $7.1million, or 77 percent of the increase. All other costs have increased $2.1 million, corresponding to a compound annual escalation of approximately one percent per year since 2009C restated.

Figure 5.7

Customer Operations ($M)			
2009C restated	**2010**	[redacted]	**2012F**
64.0	72.5	[redacted]	73.2

Figure 5.8 below shows Customer Operations costs per customer from 2009C restated to 2012.

Figure 5.8



The factors driving the increase in Customer Operations OM&G spending are outlined in Figure 5.9.

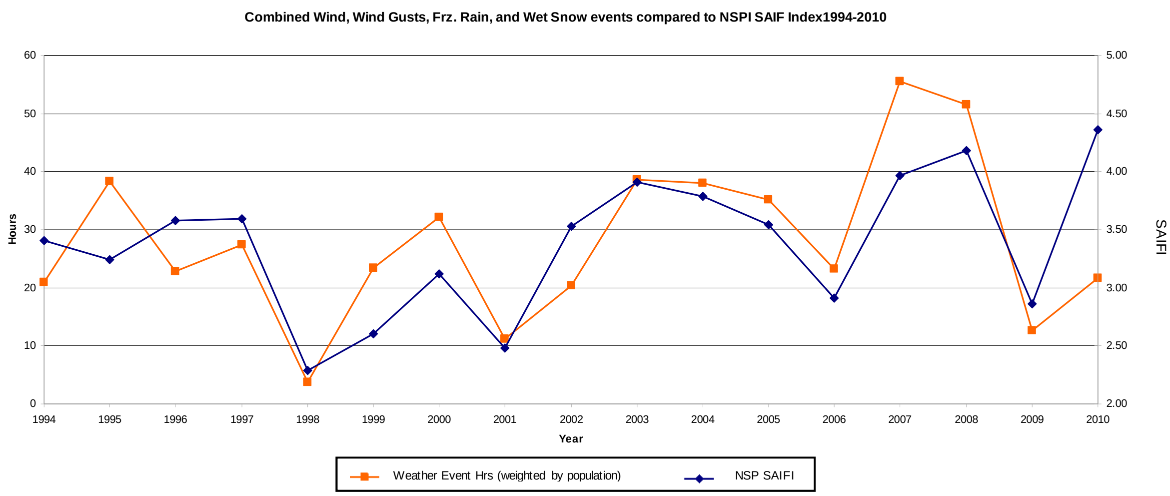
Figure 5.9

Cost	Amount ($M)
Union and non-union labour	2.9
Succession planning	1.2
Vegetation management investment	3.4
Storm response	3.7
Pension	1.9
Other (net of savings/recoveries)	(3.9)
Total	**$9.2**

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.

Figure 5.10 shows this trend. The frequency of high winds results in higher storm response costs, and the requirement to increase vegetation management investment.

Figure 5.10



Storm Response

NS Power remains strongly committed to its Emergency Services Restoration Plan (ESRP). Developed in the wake of Hurricane Juan, the plan establishes processes that quickly respond to electric power system damage resulting from severe weather. Each year, NS Power carries out simulation exercises to test the plan's capability and to train employees. The 2009 exercise scenario conducted on July 8 was a "severe ice storm". Representatives from Nova Scotia's Emergency Management Office (EMO) observed the exercise at the NS Power Emergency Operations Centre (EOC). We filed the Emergency Services Restoration Plan annual update with the UARB at the end of August 2009.

In 2009, NS Power activated its plan for three major storm events:

- January 1 – Province wide wind and snow event
- August 23 – Hurricane Bill
- August 29 – Tropical Storm Danny

During 2010, NS Power activated its plan for two events:

- September 2 – Hurricane Earl
- December 13 – Province wide wind event

NS Power's EOC proved effective in coordinating resources to shorten the duration of outage events resulting from these storms and providing customers and the provincial EMO with timely information on restoration.

Recent increase in the severity of Nova Scotia's weather have increased the costs associated with storm response and restoration. Actual storm costs for the past five years are as indicated in Figure 5.11.

Figure 5.11

Year	Storm Operating Expense ($M)	Storms Greater than $1 million
2006	3.7	No single storm event was in excess of $1 million
2007	11.7	Hurricane Noel – $6.3 million
2008	7.8	Hurricane Kyle – $1.8 million Christmas Snow Storm – $3.2 million
2009	7.7	January 1st event – $1.2 million Hurricane Bill – $1.9 million
2010	14.1	Hurricane Earl – $6.5 million December 13 Wind event – $2.7 million

The average annual operating costs for storm response over the last five years is $9.0 million. However when the 2012 forecast was developed, the final 2010 numbers were not completed. The five-year average at that point was $8.7 million which is included in the 2012 revenue requirement. Accordingly, NS Power is requesting an increase of $3.7 million in 2012 for the storm response program.

<u>Vegetation Management</u>

NS Power's Vegetation Management Program is the most effective investment to improve customer reliability. For 2012, NS Power seeks an additional $3.4 million for vegetation management.

The UARB's Decision on the 2009 GRA Settlement Agreement dated November 5, 2008, noted the following:

> In its original rate application, NSPI requested an increase of $7.0 million over the prior year, which would have amounted to a total of $13.8 million for 2009. Thus, despite the $3.4 million reduction resulting from the Agreement, an overall net increase in vegetation management will be achieved. Vegetation expenses will increase to $10.4 million for the 2009 test year, a net increase of $3.6 million over the last compliance filing.
>
> The Board notes the testimony of Mr. Bennett, who stated that increased activity in vegetation management will enhance service reliability for NSPI's customers.
>
> Taking into account all of the evidence, the Board is satisfied that the proposed total expenditure of $10.4 million for vegetation management (an increase of $3.6 million), as contemplated under the terms of the Agreement, is reasonable and appropriate in the circumstances.[18]

The $3.4 million which was not included in the 2009C was to specifically address off right-of-way hazard trees. These are trees that are not addressed through right-of-way clearing programs, but in cases of very severe wind can fall into the line causing outages. These hazard trees have continued to be a significant cause of outages during severe weather events and NS Power has therefore included the $3.4 million to address these trees in this Application.

5.4.3 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.

[18] NSPI 2009 Rate Case, UARB Decision, NSUARB – NSPI P-888, November 5, 2008, paragraph 51.

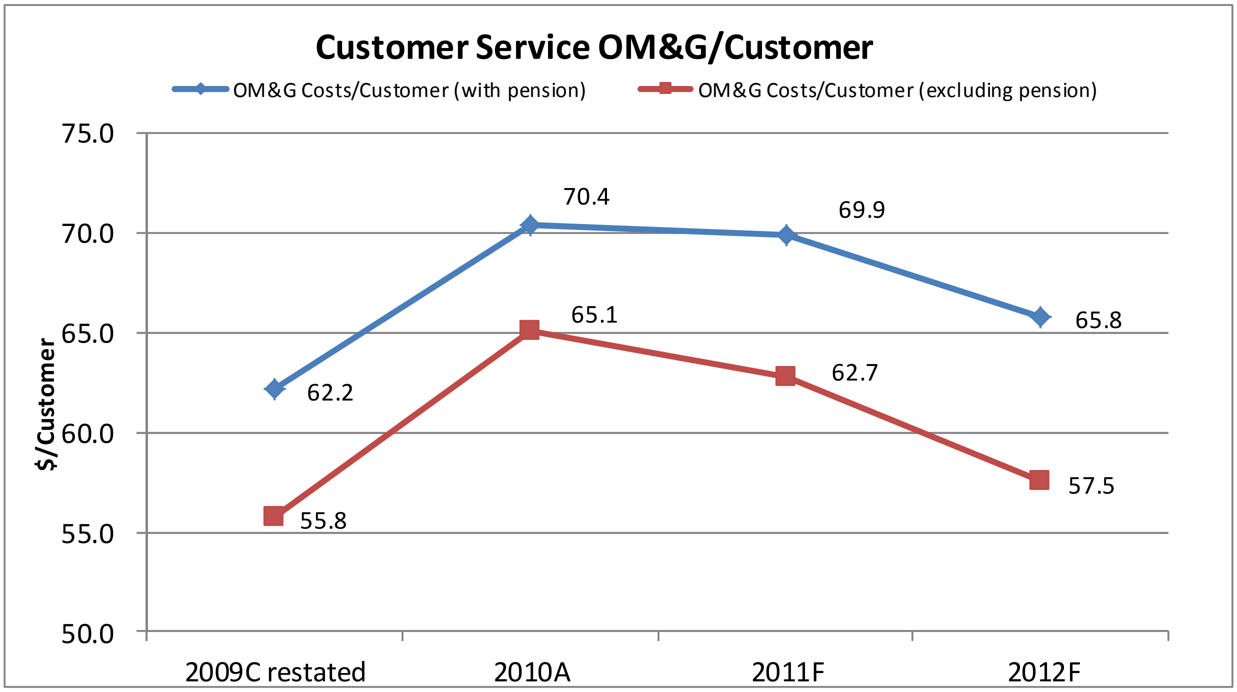
The Customer Service group accounts for about 13 percent of the total OM&G expenses forecast for 2012. In 2012, these costs will increase by $2.3 million over 2009C restated, an increase of 7.6 percent as outlined in Figure 5.12.

Figure 5.12

Customer Service ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
30.2	34.3	[redacted]	32.5

Figure 5.13 below shows Customer Service costs per customer from 2009C restated to 2012.

Figure 5.13



The 2010 and 2011F OM&G cost per customer increased over 2009C restated as the result of one-time programs and initiatives to improve customer service. This included improvements to service levels, redesign of processes to deliver improved customer experiences, and implementation of best-in-class customer service training. The factors driving the increase in Customer Service OM&G over 2009C are outlined in Figure 5.14 below.

Figure 5.14

Cost	Amount ($M)
Union and non-union labour	1.4
Pension	1.0
Electric write-off and allowances	0.5
Other costs (net of savings)	(0.6)
Total	**$2.3**

Electric write-off and allowance increase of $0.5 million is to reflect actual and forecasted write-off experience partially offset by process improvement gains in net bad debt management.

5.4.4 Technical and Construction Services

The Technical and Construction Services group focuses on the execution of initiatives to further enhance reliability, asset management and operational excellence, support for renewables, environmental 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 OM&G expense forecast for 2012. As outlined in Figure 5.15, NS Power's Technical and Construction Services group OM&G will increase by $4.1 million in 2012 to $13.5 million as compared to 2009C restated. This increase, mainly labour costs, reflects NS Power's growth in the capital program focusing on reliability, renewable development, and succession planning for specialized engineering positions.

Figure 5.15

Technical and Construction Services ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
9.4	11.7	[redacted]	13.5

The factors driving the increase in Technical and Construction services OM&G over 2009C restated are outlined in Figure 5.16 below.

Figure 5.16

Cost	**Amount ($M)**
Union and non-union labour	0.7
Added Labour	0.9
Pension	1.9
Other costs (net of savings)	0.6
Total	**$4.1**

The increase in Technical and Construction Services OM&G costs results mainly from labour costs, including wage increases and additional full time employees needed to operate and maintain the increased assets resulting from growth in the capital program. The addition of full-time employees in the Technical and Construction Services group also aligns with NS Power's succession planning. As technical employees approach retirement in the next few years, having technically competent employees to support ongoing capital investments and provide support to the operation groups ensures sustained reliability and service for customers.

5.4.5 Sustainability

The Sustainability group supports NS Power's renewable energy advancement, commercial development of multifaceted projects, and corporate strategic planning.

As outlined in Figure 5.17, NS Power's Sustainability group OM&G will increase by $0.8 million in 2012 compared to 2009C restated.

Figure 5.17

Sustainability ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
1.2	3.3	[redacted]	2.0

The factors driving the increase in Sustainability OM&G over 2009C are outlined in Figure 5.18 below.

Figure 5.18

Cost	Amount ($M)
Non-union labour	0.2
Consulting	0.5
Other costs (net of savings)	0.1
Total	**$0.8**

The main increase in consulting is due to additional expenditures related to renewable energy development activities associated with the Renewable Energy Standard compliance requirement for 2015 and beyond.

5.4.6 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.

As outlined in Figure 5.19, the OM&G relating to NS Power's Corporate Support groups will increase by $4.5 million in 2012 as compared to 2009C, an increase of 10.2 percent over three years. This increase is mainly due to increases in labour and insurance costs.

Figure 5.19

Corporate Support Group ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
44.0	46.0	[redacted]	48.5

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.[19]

Figure 5.20 identifies the cost increases in Corporate Support OM&G spending.

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

Figure 5.20

Cost	Amount ($M)
Union and non-union labour	1.4
Other labour increases	1.4
Pension	1.7
Insurance costs	1.2
Lower Water Street OM&G related savings	(2.8)
Other	1.6
Total	**$4.5**

<u>Other Labour increases</u>

The increase in activity in our capital investment program, increase requirement to attract new employees through our work force planning and apprenticeship program and our focus on succession planning and leadership development has resulted in a requirement to retain additional employees to satisfy these requirements.

<u>Insurance costs</u>

The increase is based on our most recent experience.

<u>Lower Water Street Office Facility</u>

2012 constitutes the first complete year in our new office facility. Included in the 2012 revenue requirement is a reduction of $2.8 million in OM&G costs related to our relocation to the Lower Water Street (LWS) facility. The UARB approved the LWS capital application based on a comparison to various alternatives demonstrating that the LWS alternative was the lowest long term cost option for customers. The amounts included in the 2012 revenue requirement are aligned with the estimates included in the business case that supported the approved capital application.

Other

Other costs increased $1.6 million primarily due to increases in regulatory consulting/legal and IT support contracts.

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 year-end payroll accrual and incentives).

In 2012 the corporate adjustment credit will increase by $7.4 million over 2009C as shown in Figure 5.21. This is mainly due to an increase in administrative overheads of $8.2 million (which reduces the corporate adjustment costs), resulting from increased capital investment levels.

Figure 5.21

Corporate Adjustments ($M)			
2009C restated	**2010A**	[redacted]	**2012F**
(17.7)	(29.3)	[redacted]	(25.1)

Figure 5.22 summarizes the major components of Corporate Adjustments and Overheads.

Figure 5.22

Corporate Adjustments by Expense Type ($M)				
	2009C restated	**2010A**	[redacted]	**2012F**
Payroll Costs	3.0	3.2	[redacted]	3.2
Applied Overheads	(19.2)	(31.1)	[redacted]	(27.4)
Corporate Support Transfers	(0.8)	(1.2)	[redacted]	(1.0)
Other	(0.7)	(0.2)	[redacted]	0.1
Total	**$(17.7)**	**$(29.3)**	[redacted]	**$(25.1)**

5.5 Five Year OM&G Forecast

In this Application, NS Power has included a detailed OM&G Five Year Forecast Summary. Please see Appendix E.

Detailed multi-year forecasts of OM&G are inherently uncertain. Many factors can significantly affect specific OM&G costs from year to year, including: load growth, scope and timing of plant maintenance, changes in the costs of materials, customer growth, changes in regulatory environment, changes in pension expenses, fleet fuel costs, insurance cost increases or other market changes. A variation one way or another in the early years can distort future year estimates.

NS Power did not file a 2010 or 2011 rate application and therefore the OM&G requirement for 2012 reflects a three year increase in costs. The estimated costs and percentage increases projected over five years are shown in Figure 5.23. The forecasted 2012 OM&G as filed in the 2009 General Rate Application was $245.5 million, consistent with the test year 2012 forecast in this Application, even though in 2009 we did not expect that NS Power would experience 2012 OM&G costs relating to Point Tupper, Nuttby and Digby Wind projects.

Figure 5.23

	[redacted]	**2012**	**2013**	**2014**	**2015**	**2016**
OM&G costs ($M)	[redacted]	248.5	255.6	260.6	263.9	275.5
Increase ($M)	[redacted]	[redacted]	$7.1	$5.0	$3.3	$11.6
% Change	[redacted]	[redacted]	2.9%	2.0%	1.3%	4.4%

The underlying assumptions in the five year OM&G forecast are:

- Wage increases for both union (per contract) and non-union employees
- Fleet fuel – 5.5 percent increase per annum
- Employee related expenses (other than labour) increase – 2.2 percent per annum
- Communication expenses increase – 2.2 percent per annum
- Pension costs – an increase in 2013 and decrease in years 2014 to 2016
- Contract costs – estimates based on individual circumstances or 2.2 percent
- Insurance costs – 7.5 percent annual escalation based on current insurance market
- Corporate cost allocations – remaining consistent with the 2012 percentages
- Vehicle and Administration overhead calculation - capital spend estimates consistent with the estimated capital expenditures
- Additional OM&G associated with renewable generation additions
- Remaining property costs – 2.2 percent per annum
- All other significant costs – 2.2 percent per annum
- No unforeseen regulatory mandates

Caution should be exercised as any change in forecast assumptions or actual experience can have a material effect on the costs provided in this five year forecast as each year's costs are estimated based on previous years' estimates.

6.0 CAPITAL STRUCTURE AND FINANCING

6.1 Overview

The process of generating and distributing power requires many large facilities such as coal-fired power plants, wind turbines, and transmission lines. Because these facilities have a long life expectancy, their cost can only be recovered gradually, over a period of years or even decades. Yet NS Power has to come up with the money to build them in advance. There are only two ways for us to do this. We can borrow money, and pay interest to the lender. Or we can use our shareholders' money, and pay them a return on their investment in the form of dividends.

Capital markets determine the amount of interest we will pay on borrowed money, based in part on the financial health of the company and the perceived fairness of its regulatory environment. The Utility and Review Board determines the amount of shareholder money — or equity investment — we can use, and the rate of return thereon that are included in rates.

One aspect of the transformation to cleaner, local, renewable energy sources is a shift from fuel expenses to capital expenses. We will be buying less fuel, but building more capital assets that generate energy from fuel-free sources like wind and tidal. This means that capital costs and depreciation costs will play a bigger role in our operations. Because we have to borrow the money to build those capital assets — from banks or from bondholders — it is crucial that the company remain financially sound. It is in our interests, and in our customers' interests, that NS Power remain a company to which lenders can lend with confidence, and in which shareholders can invest with the expectation of a fair return on that investment.

The bank loans and bonds that finance our new generating facilities will be paid off over a long period of time. An increase in interest charges of even a fraction of a percentage point can add millions to the cost of power from one of these plants over its lifetime. Since the Board, by law, fixes electricity rates according to our costs, higher interest rates mean higher electricity rates. The rate of interest we pay depends on the expectation of creditors — banks and bondholders — that they will get their money back, with interest, on the agreed schedule. Their expectation that this will happen depends in large part on their confidence that the company operates in a regulated environment that supports a fair rate of return on equity.

In its 2006 Rate Decision, the Utility and Review Board observed that customers have a vested interest in Nova Scotia Power's strong financial position. As the Board stated:

> The Board recognizes that the interests of customers and shareholders of Nova Scotia Power are not mutually exclusive. They both benefit from a financially sound utility.[20]

In September 2009, the rating agency Standard & Poor's (S&P) raised Nova Scotia Power's corporate credit rating to BBB+ from BBB. This action followed implementation of the FAM on January 1, 2009. In raising the company's credit rating, S&P credited the successful implementation of the FAM, and a supportive regulatory environment. S&P stated:

> Supportive, cost of service regulation underpins … regulated cash flows at … NSPI.[21]

The improvement in our credit rating benefits Nova Scotia Power and customers as the company re-finances existing debt, secures financing to fund capital projects, considers

[20] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 662.
[21] Standard & Poor's, *Global Credit Portal RatingsDirect, Nova Scotia Power Inc.*, December 10, 2009, page 2.

issuing new capital, and enters into new fuel procurement arrangements. At a time of capital investment growth, it is critical that Nova Scotia Power continue to maintain or improve our credit rating.

A strong financial position ensures NS Power will have access to the capital it needs at competitive rates, which helps control costs for customers. On an on-going basis, Nova Scotia Power requires money to re-finance existing loans as they mature. Our investments in renewable energy projects, environmental and reliability investments require capital that, if not readily accessible, could cause increased borrowing costs for Nova Scotia Power's customers. The utility must be financially sound to provide cost-effective, reliable service to customers.

To finance these requirements, Nova Scotia Power obtains capital from two sources: debt investors and equity investors. If Nova Scotia Power's returns are not competitive with other investments of comparable risk, equity investors will consider investing elsewhere. This will drive up our borrowing costs, which in turn will drive up customer rates. This point has been recognized by the Board:

> The Board understands the importance of ensuring that NSPI remain on a sound financial foundation as it heads into the future. The Company's ability to attract capital, access fuel markets and control costs must not be compromised.[22]

6.2 Credit Ratings

A credit rating is an independent rating agency's opinion of a company's creditworthiness – its ability to pay its debt holders on schedule. It is the single most important factor influencing risk assessments of fixed income securities and bank credit terms. The higher the credit rating, the greater the perceived likelihood that debt

[22] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 665.

investors will get their interest and principal payments as expected. A company with a higher credit rating makes a more attractive investment. A lower credit rating can impair a company's access to capital markets, driving up the cost of borrowing, and even affecting the availability of debt and credit.

Throughout the recent financial crisis, Nova Scotia Power has been able to successfully access short term debt markets.

Lower credit ratings reflect increased investor risk; investors expect risky investments to produce a higher rate of return. Some investors, such as pension funds and certain institutional investors, are prohibited from investing in debt instruments below a certain rating. The lower the credit rating, the more stringent the terms, and the more restrictive the covenants on new issues. Nova Scotia Power's credit rating therefore affects not only the cost of the debt, but also the amount and nature of capital that is available to the company.

Borrowing costs are not the only part of our business that credit ratings affect. Credit ratings also have an impact on our ability to purchase fuel. Since fuel contracts usually span deliveries and payments over a period of time, sellers want some assurance of a buyer's ability to meet the contracted terms. Most sellers require a certain minimum credit rating when selling commodities. If a buyer does not have an adequate credit rating, sellers may require them to "post margin" or make a deposit with the seller to ensure payment. This increases the buyer's costs. When markets are tight, it is possible that buyers with lower credit ratings may not have financial access to the commodities in question, and the supply will instead go to companies with higher credit ratings. This is a situation Nova Scotia Power and its customers must avoid.

Nova Scotia Power's Ratings

As shown in Figure 6.1, Nova Scotia Power's credit ratings, despite the raised credit rating in 2009, are in the lower range of those held by other regulated Canadian utilities.

Figure 6.1

Canadian Electric Utilities	Dominion Bond Rating Service (DBRS) Rating[1]	Trend	Rating Confirmed	S&P Rating[1]	Creditwatch/ Outlook	Rating Date Last Upgraded, Downgraded or Outlook Changed
Altalink L.P[2]	A	Stable	9-Feb-2011	A-	Stable	3-Mar-2005
CU Inc.	A (high)	Stable	8-Sep-2010	A	Stable	7-Jan-2004
ENMAX Corp.	A (low)	Stable	21-Jan-2011	BBB+	Stable	21-Sep-2010
EPCOR Utilities Inc.	A (low)	Stable	7-Jul-2010	BBB+	Stable	19-Jun-2002
Maritime Electric Co. Ltd.[3]				BBB+	Stable	19-Jun-2007
Nova Scotia Power	A(low)	Stable	25-Nov-2010	BBB+	Stable	14-Sep-2009
Enbridge Inc.	A	Stable	1-Nov-2010	A-	Stable	25-Nov-2003
TransAlta Corp.	BBB	Stable	27-Aug-2010	BBB	Stable	6-Feb-2006
Fortis Inc.	A (low)	Stable	1-Oct-2010	A-	Stable	19-Jan-2007

1. Unless otherwise stated, rating shall be the rating then assigned to such entity's unsecured debt obligations or if it has no such rating, its issuer or general corporate rating.
2. DBRS does not provide an unsecured debt or issuer/corporate credit rating for Altalink L.P. This is its Senior Secured Bond and Medium-Term Notes (Secured) rating.
3. DBRS does not provide a rating for Maritime Electric Co. Ltd.

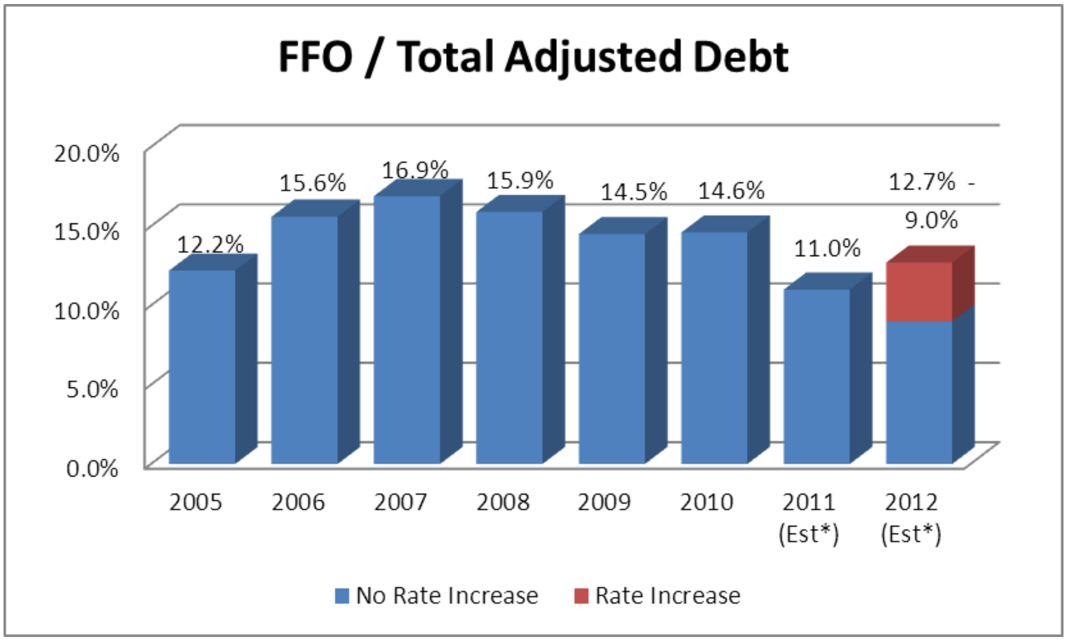
Accordingly, to maintain a competitive credit rating, Nova Scotia Power's financial profile – including its capital structure – should be at least comparable to that of other Canadian utilities. Nova Scotia Power's common equity component is currently lower than most of the utilities listed above as noted in the evidence presented by Ms. Kathleen McShane in Appendix F.

Capital structure is an important component of a company's overall credit standing.

Credit rating agencies assess the long term viability or solvency of a company by comparing the company's cash flow to the company's total debt. Cash flow is the difference between cash coming into and out of a company. Cash enables the company to meet its interest commitments to debt holders on an ongoing basis and, ultimately, repay the principal as well. Of particular concern are funds from operations (FFO), which represent the net cash derived from the day-to-day running of the business before deducting outlays for capital expenditures. The primary financial ratios that rating agencies consider when performing credit assessments are FFO/debt and FFO/interest which measure a company's ability to service the principal and interest obligations of its debt with funds provided from day-to-day operations.

Absent a rate increase, Nova Scotia Power estimates its 2012 FFO/debt metric to be 9 percent and its FFO/interest ratio to be 2.3 times. These are below the five year average of 15.5 percent and 3.2 times. With the proposed rate increase, Nova Scotia Power estimates its 2012 FFO/debt metric to be 12.7 percent and its FFO/interest ratio to be 2.9 times.

Figure 6.2



Notes:

Based on Nova Scotia Power Forecast

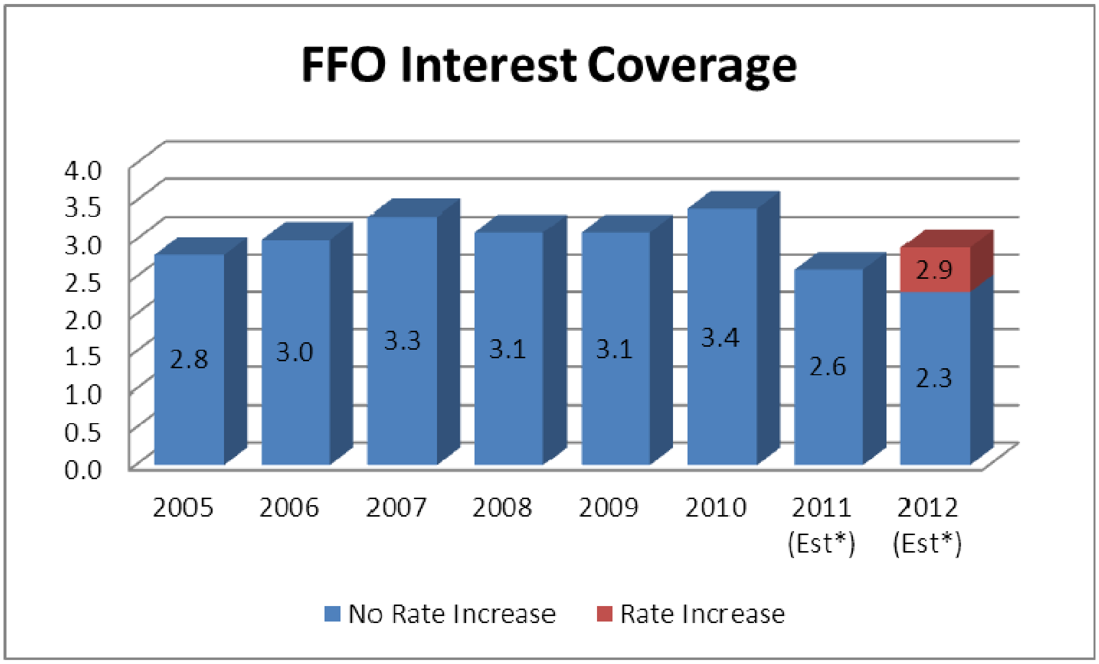
Historical metrics based on published S&P reports

Estimated metrics based on current understanding of S&P adjustment methodology

When insufficient detail exists to produce an adjustment, the 2010 adjustment has been used in its place (includes operating leases, post-retirement benefits, and foreign exchange gains/(losses))

Actual metrics will differ from estimated

Figure 6.3



Notes:
Based on Nova Scotia Power Forecast
Historical metrics based on published S&P reports
Estimated metrics based on current understanding of S&P adjustment methodology
When insufficient detail exists to produce an adjustment, the 2010 adjustment has been used in its place (includes operating leases, post-retirement benefits, and foreign exchange gains/(losses)
Actual metrics will differ from estimated

It is critical to have sufficient cash flow in order to at least maintain credit ratings. This will ensure on-going access to capital and credit and enable Nova Scotia Power to continue providing service at a reasonable cost to customers.

6.3 Return on Equity: Compensation for the Equity Investor

Return on Equity is the combined effect of the level of equity recognized for rate making and the percentage return on that equity.

Nova Scotia Power's return on equity is the compensation provided to the equity investor as a return on investment. It is analogous to the interest that is paid to debt investors. The return that can be earned by investors is assessed in terms of the risk of the investment compared to other alternatives.

The 2009 Rate Case Settlement Agreement approved rates being set on a return on common equity of 9.35 percent on 37.5 percent common equity.[23] Unlike pure transmission and distribution utilities, Nova Scotia Power is subject to operating risks in its generation business. Therefore, investors expect their fair return on investments in Nova Scotia Power to be higher than the allowed returns for utilities without this risk.

From an investor perspective, Nova Scotia Power has a relatively high risk profile compared to other investor-owned Canadian regulated electric utilities.

Subsequent to the 2009 General Rate Application, important events have occurred that have an effect on Nova Scotia Power's capital structure:

1. Certain Canadian utilities have recently been granted improvements to their ROE and percentage of common equity invested. The evidence of Kathleen McShane provides further details in this regard. These improvements recognize the increasing complexity and risk associated with operating a utility in Canada. As noted above, to maintain its credit rating, it is important that Nova Scotia Power

[23] NSPI 2007 Rate Case, UARB Decision, NSUARB – NSPI – P-886, February 5, 2007, paragraph 13, #8.

remain comparable with other utilities. Most of these utilities are subject to less risk than Nova Scotia Power as they are not vertically integrated utility companies. Nova Scotia Power's business includes the higher risk generation aspect of its business in addition to the transmission and distribution businesses of most of the other Canadian utilities.

2. On April 1, 2009 Nova Scotia Power redeemed $125 million of preferred shares. At that time, the cost to re-issue preferred shares was more expensive than to finance with debt. This reduced the amount of equity invested in Nova Scotia Power from a rating agency perspective and increased the percentage of debt financing in the company. This demonstrates the importance of maintaining our credit rating.

3. In January 2010, as part of the ROE Settlement Agreement, the UARB ordered that Nova Scotia Power maintain its common equity invested at a maximum of 40 percent.[24] This restriction on equity challenges Nova Scotia Power's credit rating as it minimizes the amount of equity on which investors can receive a return and creates a maximum leverage of debt and preferred shares to 60 percent.

4. Other risk factors include: (i) Nova Scotia RES goals and potential penalties plus federal GHG targets and impact on our thermal units, (ii) FAM deferrals, (iii) increased capital program and related risk of recovery of capital in a timely manner, and (iv) risk of more extreme weather events and storm costs.

In order to maintain its existing rating and minimize financing costs for customers, it is important that Nova Scotia Power recover its costs in rates to offset these challenging factors from a rating perspective.

[24] NSPI – Calculation of NSPI's Return on Equity, UARB Order, NSUARB-NSPI-P888(2), January 20, 2010, page 2.

Ms. McShane's expert evidence supports an ROE of 10.6 percent. While we do not question this evidence, we understand that this level of ROE is too large for a one-time adjustment in the context of this Application and would create challenges for our customers. As a result, NS Power requests that the ROE for rate setting purposes be increased to 9.60 percent. We believe this is an acceptable level of change for this Application. This is the rate of return Nova Scotia Power has earned since 2009 and is within existing range of return, which is considered a reasonable range. Given the evidence and expert opinion presented in this Application we request that rates should be set at this level and a new range established from 9.35 to 9.85 percent.

Since financial markets continue to display levels of uncertainty, it is critical that Nova Scotia Power be able to compete for capital on a level playing field. As noted above, comparable Canadian utilities now have ROEs that are higher than Nova Scotia Power's. This reflects the changing demand for increased returns in the market. The risk inherent in Nova Scotia Power's business has increased and in addition the return that the market is expecting from utilities has increased.

NS Power has retained ROE expert Kathleen McShane to provide evidence on Nova Scotia Power's return on equity and capital structure.

6.4 Financing Outlook

Cost of capital represents the costs of providing returns to suppliers of capital including commercial paper investors, bondholders and preferred and common shareholders. As an asset intensive business, Nova Scotia Power's financing costs are significant. Therefore, access to various types of financing that give NS Power flexibility to take advantage of favourable financing options is fundamental to providing cost-effective service to customers.

Debt and Interest

Nova Scotia Power uses a mix of fixed (long-term) and floating rate (short-term) debt in its capital structure. Long-term interest rates are generally higher and less volatile than shorter-term interest rates.

NS Power's floating rate debt is obtained largely through its $400 million Commercial Paper (CP) Program. CP is short-term debt issued to investors with maturities of anywhere from a day to less than one year.

The predominant rating used by commercial paper investors in Canada is provided by the Dominion Bond Rating Service. Nova Scotia Power's current rating of R1 (Low) is the minimum credit rating that allows an issuer to participate in this market without the requirement for a prospectus. CP is the lowest cost form of borrowing for Nova Scotia Power. Participating in this market provides Nova Scotia Power with flexibility in managing its cash flow, typically rolling over amounts between $10-25 million daily. Maintaining the current DBRS credit rating is imperative to have access to this efficient form of debt financing.

Nova Scotia Power plans to participate extensively in the CP market throughout 2012. The 2012 forecast monthly average short-term rate is in the 2.5 to 4.0 percent range.

To issue long-term debt in the Canadian market, every issuer offering to sell securities to the public is required to file a prospectus with the provincial securities commission of each province in which it expects the securities to be held. A prospectus is a legal document that describes the types of securities being offered for sale in the market. The prospectus provides all relevant information to potential investors so they may assess the quality of the investment, to determine if they want to participate in the offering. Rather than issuing a separate prospectus for every issue, some companies will file a "shelf-prospectus" which enables the company to issue up to a prescribed dollar amount of securities over a 25 month period.

On May 3, 2010, Nova Scotia Power renewed its existing shelf-prospectus which has enabled it to issue up to $500 million in medium term notes (MTN)[25] or preferred shares for the 25 month period subsequent to that date. To date, NS Power has issued $300 million relating to this prospectus. The issues are typically carried out through NS Power's banking syndicate which includes six major Canadian banks and one major U.S. bank who sell the debt to institutional investors such as pension plans, insurance companies and governments. Before NS Power issues debt, it is required to confirm its credit ratings with the rating agencies in order for the issue to proceed.

Lower credit ratings attract fewer investors, and consequently lead to higher rates. In addition, lower credit ratings result in fewer options in available terms; that is, terms in excess of 10 years are not available for some entities with BBB ratings, increasing an issuer's re-financing risk.

Nova Scotia Power has no long-term debt maturities in 2011 and 2012.

[25] Medium Term Notes are debt securities that in today's market can range from terms of two to thirty years.

Preferred Equity

Nova Scotia Power has $135 million of preferred equity in its capital structure. Preferred stock is a class of share capital that entitles the holder to a fixed dividend before any dividends are paid to common shareholders and to a stated dollar value in the event of liquidation. Preferred dividends for 2012 are reduced from previous applications due to the redemption of $125 million in preferred shares in April 2009. The annual preferred share dividend requirement is now $8.0 million.

Nova Scotia Power's local long-term Preferred Share rating of BBB- from S&P is one notch above non-investment grade. Non-investment grade securities require high yields (that is high dividend rates) to be successfully marketed and/or attract limited investor interest because of the ineligibility for inclusion in investment portfolios.

On or after October 15, 2015, Nova Scotia Power Preferred Series "D" shares are convertible into common equity of Emera at the option of the holder, or can be redeemed at the option of Nova Scotia Power. In either circumstance, Nova Scotia Power will have a re-financing requirement. With a non-investment grade rating on preferred shares, this form of financing may be prohibitive from a cost and/or marketability perspective.

If Nova Scotia Power does not have the option of a preferred share issuance, we will be required to increase its common equity component in order to sustain its DBRS credit metrics. This represents another longer-term implication of a ratings downgrade that puts upward pressure on customer rates.

Common Equity

In the 2002 Rate Decision, the Board set rates using 35 percent common equity and said:

> The Board would indicate that it has no objection to NSPI increasing its actual equity ratio in the future to 40 percent. However, at any future rate hearing, the Board will determine what equity ratio is appropriate for ratemaking purpose. [26]

In the 2005 Rate Decision, the UARB approved an increase in Nova Scotia Power's common equity to 37.5 percent for rate-making purposes, which was upheld in the 2006 Rate Decision. The Board said:

> The Board has considered the evidence concerning this matter and approves the proposed increase in the common equity ratio for ratemaking purposes from 35 percent to 37.5 percent. The Board is satisfied that the strengthening of the balance sheet in this way is desirable in the current economic climate. The Board notes that the majority of interveners appear to be in favour of the proposed increase in the common equity thickness.[27]

The last time Nova Scotia Power obtained common equity from the markets was late in 2002, following the 2002 Rate Decision. At that time, Emera issued common equity and injected one-half of the proceeds into Nova Scotia Power to strengthen its balance sheet. Emera did this to maintain Nova Scotia Power's credit rating, which was under negative credit watch by DBRS.[28] Since that time, Nova Scotia Power has maintained regulated common equity of at least 37.5 percent.

NS Power is proposing to maintain common equity of 37.5 percent for establishing electricity rates. Nova Scotia Power is proposing to maintain its actual common equity between 35 percent and 40 percent. NS Power will continue to report its regulated return on equity based on its actual average common equity.

---

[26] NSPI 2002 Rate Case, UARB Decision, NSUARB – NSPI – P-875, October 23, 2002, paragraph 156.
[27] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P-881, March 31, 2005, paragraph 166.
[28] DBRS Press Release: Nova Scotia Power Inc. "Under Review with Negative Implications", October 30, 2002. 2007 Rate Case, NSPI Direct Evidence, Appendix D, Attachment 5.

7.0 RATE BASE

7.1 Overview

The rate base consists of assets Nova Scotia Power uses to generate and distribute electricity. In its 2006 GRA Decision, the Utility and Review Board summarized it this way:

> The Public Utilities Act clearly contemplates that all assets of a utility which are used and useful in supplying a regulated service shall be included in the rate base fixed by the Board with respect to that particular service.[29]

The rate base includes capital assets like power plants, transmission and distribution lines, inventories of fuel materials and supplies used to produce and distribute electricity, and financial assets like working capital and regulatory assets. Rate base is a component of setting our revenue requirement and in turn setting rates.

Because of that, determining the rate base is an important part of a General Rate Application. This Application uses the same method for calculating the rate base as used in our 2006 and 2009 General Rate Applications.

The average rate base for the 2012 test year is $784.8 million higher than the 2009 Compliance Filing. Several components contributed to the change:

- average capital assets increased by $906 million
- working capital increased by $33 million
- average contract receivables decreased by $83 million
- average deferred charges and credits decreased by $70 million

[29] NSPI 2006 Rate Case, UARB Decision, NSUARB-NSPI-P-882, December 22, 2005, paragraph 170.

Figure 7.1 sets out the components of NS Power's average regulated rate base for the 2012 test year, consistent with UARB Rate Decisions in 2006 and 2009. We have provided details in RB-02 to RB-16 of this Application.

Figure 7.1

Average Rate Base	2009C ($M)	2012F ($M)
Average capital assets	2,447	3,353
Average cash working capital allowance	67	59
Working capital adjustment (by agreement with stakeholders)	(41)	-
Average materials and supplies inventory	124	123
Average contract receivable	83	-
Average deferred charges & credits	160	90
Total	**$2,840**	**$3,625**

7.2 Details of Rate Base

Average Capital Assets

Average capital assets reflect Nova Scotia Power's actual capital asset balances as of December 31, 2010. The assets also include items submitted in our 2011 Annual Capital Expenditure Plan and the projected capital program for 2012, reduced by the December 31, 2010 accumulated depreciation and the depreciation forecast for 2011 and 2012 as detailed in Section 4 of this Application.[30]

Average capital assets have risen sharply because Nova Scotia Power is in a period of historic change. Nova Scotia has legislated an increase in cleaner, renewable electricity.

[30] Refer to FOR-12.

This is an investment in lower carbon emissions and a cleaner environment. Environmental regulations have enabled NS Power to begin making investments that support increased renewable generation regulations in Nova Scotia.

Although NS Power's generation mix now includes more renewable energy, and therefore less price volatility, fossil fuels and hydro continue to provide the majority of the power system's energy. Maintaining and/or improving the reliability and capability of Nova Scotia Power's thermal and hydro generating units helps preserve lower fuel prices and maintain system stability.

New renewable generation must be connected to our electrical systems. This has required new investment in NS Power's transmission and distribution system and this has contributed to the increase in our average capital assets.

Cash Working Capital Allowance

Cash working capital allowance (CWC) represents the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items. CWC investments bridge the gap between the time expenditures are made and payment is received. This allowance is determined using a lead/lag study, which analyzes cash flows arising from our billing, paying and collecting procedures, with the goal of determining the average amount of outstanding working capital.[31]

To support its lead/lag assumptions, NS Power contracted John T. Browne, CA, of JT Browne Consulting to provide an appropriate method for determining these assumptions.

[31] Refer to FOR-15, which contains Nova Scotia Power's calculations for working capital using the lead/lag methodology.

Mr. Browne also reviewed NS Power's lead/lag calculations and provided an opinion on the appropriateness of our assumptions and calculations. He performed this study in early 2011, using data from 2009.[32] His findings are included in SR-04 of this Application.

We have applied the lead/lags supported by Mr. Browne's study to 2012 data to form the basis of the CWC request used in this Application.

The forecasted 2012 CWC is $54.8[33] million, a decrease of $14.0 million from the 2009 Compliance Filing. The change results from decreased net lag days for income taxes and decreased income tax expense partially offset by increased net lag days for OM&G excluding labour, increased OM&G and grants in lieu of taxes expenses and Demand Side Management.

To calculate the average rate base we need to calculate the average CWC. Average CWC included in the 2012 test year rate base is $59.1 million, a decrease of $7.8 million from 2009 Compliance.

As part of the 2009 General Rate Application Settlement Agreement, the allowance for cash working capital was arbitrarily reduced by $40.9 million.[34] We have not included this reduction in our 2012 rate base calculation.

[32] 2009 was selected in the 2011 study as it was the most recent timeframe for which a complete year of data was available.
[33] Refer to FOR-15.
[34] Refer to RB-02 – RB-16, line 20.

Materials and Supplies Inventory

We have based our fuel and supplies inventory on the projected monthly average for 2012, consistent with the methods used in the 2009 General Rate Application. It consists primarily of coal and oil inventory, thermal plant inventory and of transformers and conductor to support the transmission and distribution system.

Average materials and supply inventory included in the 2012 test year rate base is $122.6 million,[35] a decrease of $0.9 million from 2009 Compliance.

Deferred Charges and Credits

NS Power's method for calculating deferred charges and credits conforms to the 2006 through 2009 General Rate Applications. In those applications, we included all components of the deferred charges and credits on our rate base calculation, and the UARB confirmed this approach in all three of these rate decisions.

Deferred charges represent amounts that NS Power has paid to operate the utility, but have not yet expensed. These amounts have not been reflected in customer rates. Such items are useful for a number of reasons. For example, deferred charges include costs incurred to fund the pension plan, which is part of employee compensation, and costs incurred to execute debt transactions that are required to operate the business or pay past taxes on behalf of customers. A fair return on the assets compensates investors for the use of these funds.

[35] Refer to FOR-14.

The average deferred charges and credits for the 2012 test year are $90.2 million, a decrease of $70.1 million over the 2009 Compliance Filing. NS Power's deferred charges and credits are outlined in Figure 7.2.

Figure 7.2

Deferred Charges & Credits	2009 Average ($M)	2012 Average ($M)
Defeasance & Finance Charges	121	88
Section 21 and 2005 Q1 taxes	112	56
Prepaid Pension Asset	7	58
FAM Regulatory Asset	8	48
Asset Retirement Obligations	(90)	(149)
Future Income Taxes	-	(15)
Other	2	4
Total	**$160**	**$90**

The amounts included in rate base reflect a year-end average, consistent with the method approved by the Board in previous rate cases. The $70 million reduction is primarily a result of:

- defeasance & financing charges amortization reductions of $33 million
- amortizations reductions of Section 21 and 2005 Q1 taxes and the income tax recovery associated with pre-2003 taxes received of $56 million
- pension asset increase of $51 million
- fuel regulatory asset deferral increase of $40 million
- asset retirement obligation increase of $59 million
- addition of future income tax liability associated with the FAM of $15 million
- other increase of $2 million

Further explanation of these assets is described below.

Defeasance and Finance Charges

Defeasance costs are included in average rate base as approved in the past three rate decisions. The reduction of $33 million in the average is due to amortizations on the defeasance deferred charges. We have amortized these deferred amounts over the life of the new debt in accordance with the UARB's 1993 Rate Decision.[36]

Section 21 and 2005 Q1 Taxes

In the 2006 Rate Decision, the Board approved the inclusion of the Section 21 taxes in the rate base. Subsequently, the UARB approved the deferral of $16.7 million of taxes in Q1 of 2005, representing amounts associated with the deferral of taxes in the first quarter of 2005. In the 2007 Rate Decision, the Board approved the commencement of amortization of these assets. During 2009 and 2010, adjustments in addition to amortization have occurred and are detailed in Section 4 of this Application. As a result, the average deferred balance for taxes has decreased by $56 million.

Prepaid Pension Asset

The average prepaid pension asset increased $51 million over 2009C resulting in an average prepaid pension asset for 2012 of $58 million. This increase reflects the difference between the funding provided to the pension plan by NS Power less the amount expensed by NS Power as calculated by its actuary. Pension expense referred to above is what is included in OM&G expense and included in the 2012 revenue requirement.

[36] NSPI 1993 Rate Case, UARB Decision, NSUARB – NSPI – P-863, April 5, 1993, page 25.

For the 2012 test year, NS Power forecasts pension funding at the minimum required amount of $43.9 million, while pension expenses are forecast to be $40.8 million.[37]

Fuel Adjustment Mechanism

For the 2012 test year, NS Power's fuel adjustment reflects the actual adjustment resulting from an under-recovery of fuel costs in 2010, and the 2009 balance adjustment. This under-recovery is reduced in 2011 and 2012 for the UARB- approved FAM deferral issued December 13, 2010. We have included the actual vs. forecast under recovery from November and December for collection in 2012, reducing the FAM ending balance.

Demand Side Management

The deferral and amortization of DSM applies to the costs recognized in the 2009 Rate Application and approved by the Board.

Asset Retirement Obligations (ARO)

Nova Scotia Power recognizes an obligation associated with the retirement of tangible, long-lived assets that it is required to settle. NS Power accrues a liability for the fair value of its obligation to decommission a site when the obligation arises. At that time, a corresponding asset retirement cost is added to the carrying amount of the related asset.

NS Power deducts the obligation from rate base. The average ARO amount deducted from NS Power's average rate base in 2012 is $149 million, an increase of $59 million over 2009C.

[37] Refer to OE-02 – OE-09.

Future Income Taxes

Future income taxes relate to the accounting treatment of income taxes through the FAM as approved by the Board.

8.0 LOAD FORECAST

8.1 Overview

Peak demand and customer energy requirements have a significant effect on the costs associated with running NS Power. Growth in peak demand can affect fixed costs over the long-term, while growth in electric energy consumption drives up variable operating costs. As such, the electric load forecast, which provides an outlook on the energy and peak demand needs by month, is an essential part of determining future costs. The load forecast also helps us allocate costs among different types of customers, in what's known as the cost-of-service model (spelled out in Section 9 - Cost of Service).

The Nova Scotia net in-province requirement, including losses for the 2012 test year is 12,647 GWh. This is 270 GWh below the 12,917 GWh used in the 2009 General Rate Application and 235 GWh above the 12,412 GWh used in the 2011 FAM Base Cost of Fuel reset. The forecast estimates the provincial load in three primary sectors (residential, commercial and industrial) which are then divided into the various customer sales classes. Details can be found in the 2011 Load Forecast Report (SR-02).

Key points of the 2012 load forecast include:

- In-province electric energy sales, which had grown at an average annual rate of 1.0 percent over the previous five years, fell by 3.6 percent in 2009 due to the economic recession which mainly affected electric consumption in the industrial sector. Sales partially rebounded in 2010, with 1.4 percent growth, despite warmer than average weather. Sales are forecast to continue to recover in 2011 and 2012.

- The 2012 residential sector sales are forecast to increase by 5.2 percent over 2010 actual sales, owing to the economic recovery and the expected return to normal (colder) winter temperatures. We expect commercial sales in 2012 to increase by 1.5 percent over 2010. We expect industrial sales in 2012 to grow by 2.2 percent over 2010 sales, driven by a return to normal production levels at the largest paper mills and several other large industrial customers.

  Efforts to reduce electricity use, via Demand Side Management, will influence growth rates in 2012; we expect DSM to reduce overall electric load by 301 GWh during the year.[38]

- We forecast demand for the winter of 2011/2012 to peak at 2,308 MW, 194 MW above the peak demand of 2,114 MW experienced in the winter of 2009/2010, when temperatures were in the range of minus 13°C but some large industrial customers were operating at reduced load. The 2011/2012 forecast is 70 MW above our highest recorded peak, set seven years ago, in January 2004 at 2,238 MW, when temperatures fell to minus 18°C.

The following sections summarize the development of the test year load forecast.

8.2 Models

Our load forecast uses surveys, econometric and end-use information, and assumptions about the economic, demographic, and technological environment in the forecast period.

[38] The load forecast was completed in December 2010 and DSM amounts noted are based on the DSM projections of the 2009 Integrated Resource Plan forecast.

We model the residential, commercial, and industrial components of total electricity demand, and we take account of line losses associated with supplying load.

To keep forecasting procedures accurate, we test alternate econometric models and when these changes improve the process and enhance accuracy, we update our models accordingly. The 2011 Load Forecast Report describes our current procedures.

Figure 8.1 displays the annual year-ahead forecast and actual in-province load, and shows the variance between the two. The table shows a decrease in overall load since 2007, due to DSM, the economic downturn and major load reductions at the largest industrial customers. Actual results also reflect the impact of weather effects on electric load. The 2011 Load Forecast Report sets out the econometric model equations and regression statistics.

Figure 8.1

NS Power In-Province Energy Forecast Accuracy

Year	Forecast GWh	Actual GWh	Variance GWh	% Variance	Weather-Adj Variance GWh	Weather-Adj. % Variance
2000	11,043	11,240	197	1.8	291	2.6
2001	11,439	11,303	-136	-1.2	-75	-0.7
2002	11,704	11,501	-203	-1.7	-161	-1.4
2003	11,833	12,009	176	1.5	152	1.3
2004	12,289	12,388	99	0.8	45	0.4
2005	12,663	12,338	-325	-2.6	-253	-2.0
2006*	12,850	10,946	-1,904	-14.8	-1,675	-13.0
2007	12,981	12,640	-341	-2.6	-400	-3.1
2008	12,864	12,539	-325	-2.5	-313	-2.4
2009*	12,917	12,073	-844	-6.5	-896	-6.9
2010	12,444	12,158	-286	-2.3	-134	-1.1

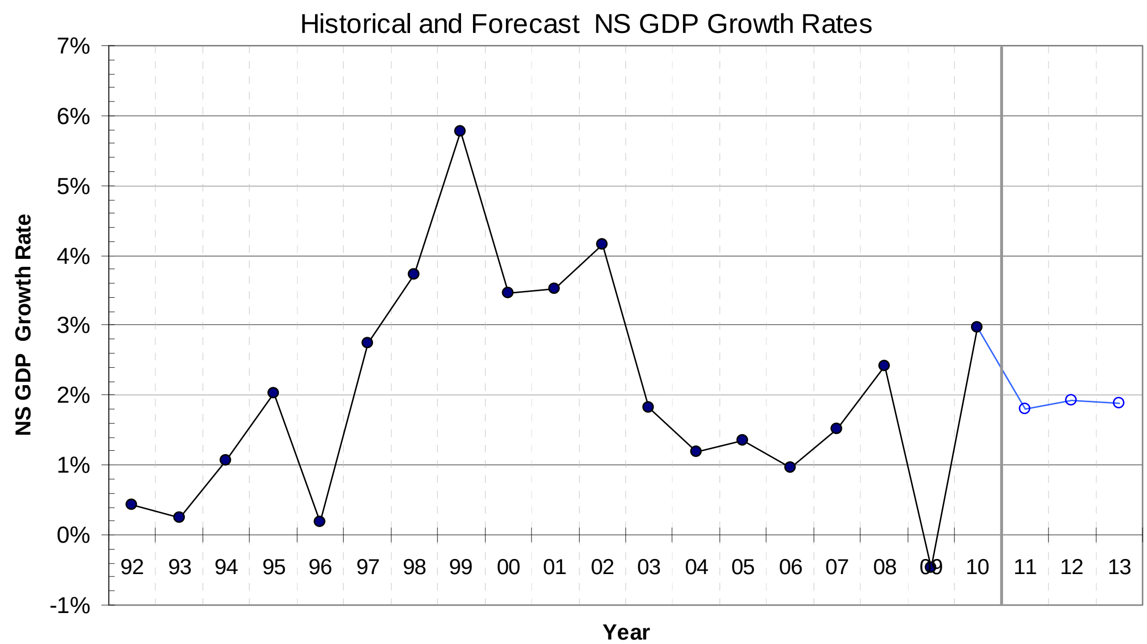
* 2006 and 2009 saw shutdowns at major industrial customers and the 2006 heating season was much warmer than average.

8.3 Economic Indicators

Economic indicators such as Gross Domestic Product (GDP) play a major role in the load forecast models. Historical trends show that electricity load growth and economic growth are closely linked. The most significant economic indicator used in commercial and industrial sector load forecast models is the Provincial GDP, or the total value of all goods and services produced within the Province. Our models use Nova Scotia economic indicators and demographic data drawn from the latest available Conference Board of Canada's economic forecast (October 2010).

Figure 8.2 shows historical and projected GDP growth rates. The Conference Board of Canada forecasts the Nova Scotia GDP to grow by 1.8 percent in 2011 and 1.9 percent in 2012.

Figure 8.2



Source: Conference Board of Canada

The Conference Board of Canada forecasts real personal disposable income to increase by 0.4 percent in 2011 and 1.8 percent in 2012, after averaging 2.1 percent annual growth over the last five years. The Board expects sales of consumer goods sales to recover with anticipated growth of 0.8 percent in 2011 and 1.6 percent in 2012. Consumer goods growth has averaged 1.8 percent over the last five years. The board forecasts 4,382 total housing starts in 2010, decreasing to 3,328 in 2012.

8.4 Updated Energy Forecast

Section SR-02 contains the full 2011 Load Forecast Report. The following sections summarize the highlights and results of the forecast.

8.4.1 System Requirement

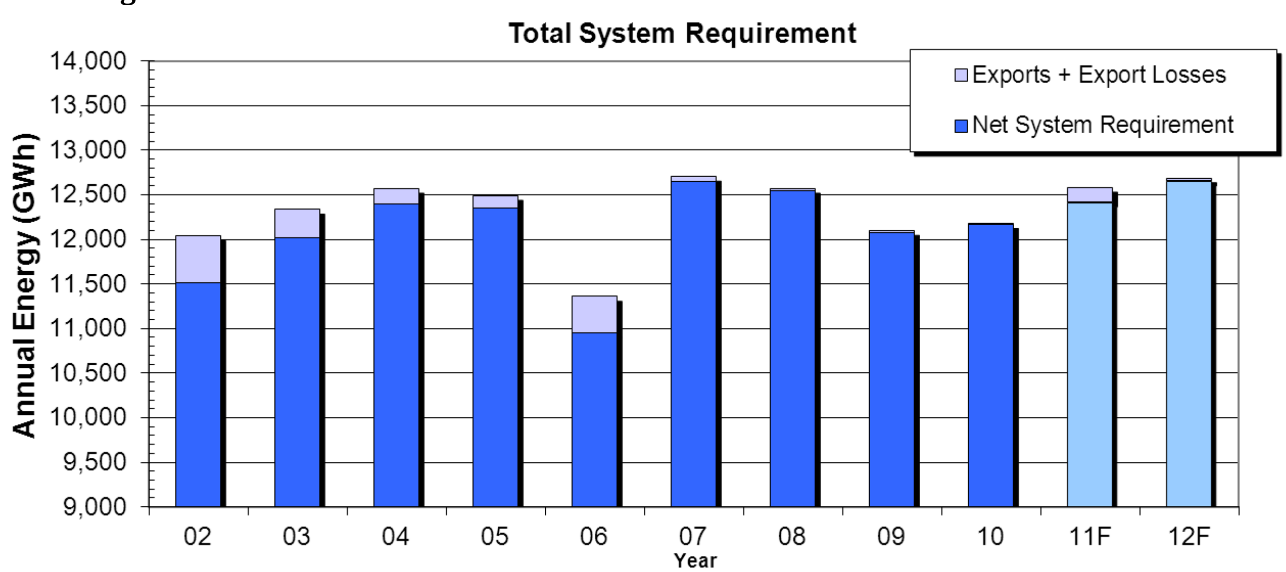
The total energy requirement is the sum of residential, commercial, and industrial sales, plus export sales and associated losses. Total requirement grew by an average of 0.4 percent per year from 2003-2008, then dropped 3.8 percent due to the 2009 recession. As shown in Figure 8.3, we forecast a total energy requirement for the 2012 test year of 12,682 GWh.

Figure 8.3

Year	Residential GWh	Commercial GWh	Industrial GWh	Losses GWh	Net System Requirement (NSR) (In-Province) GWh	Growth %	Export + Export Losses GWh	Total System Requirement GWh	Growth %
2000	3,672	2,829	3,930	809	11,240	3.4	192	11,432	3.2
2001	3,741	2,959	3,873	730	11,303	0.6	343	11,646	1.9
2002	3,829	2,996	3,799	877	11,501	1.8	530	12,031	3.3
2003	4,011	3,091	4,046	862	12,009	4.4	320	12,329	2.5
2004	4,114	3,188	4,212	874	12,388	3.2	177	12,565	1.9
2005	4,114	3,223	4,215	786	12,338	-0.4	145	12,483	-0.7
2006	3,979	3,211	2,888	868	10,946	-11.3	406	11,352	-9.1
2007	4,218	3,343	4,207	872	12,639	15.5	60	12,699	11.9
2008	4,232	3,327	4,161	818	12,538	-0.8	25	12,563	-1.1
2009	4,318	3,320	3,658	776	12,073	-3.7	19	12,092	-3.7
2010	4,216	3,305	3,932	704	12,158	0.7	6	12,164	0.6
2011F	4,362	3,253	3,966	830	12,412	2.1	164	12,574	3.4
2012F	4,437	3,355	4,018	836	12,647	1.9	34	12,682	0.8

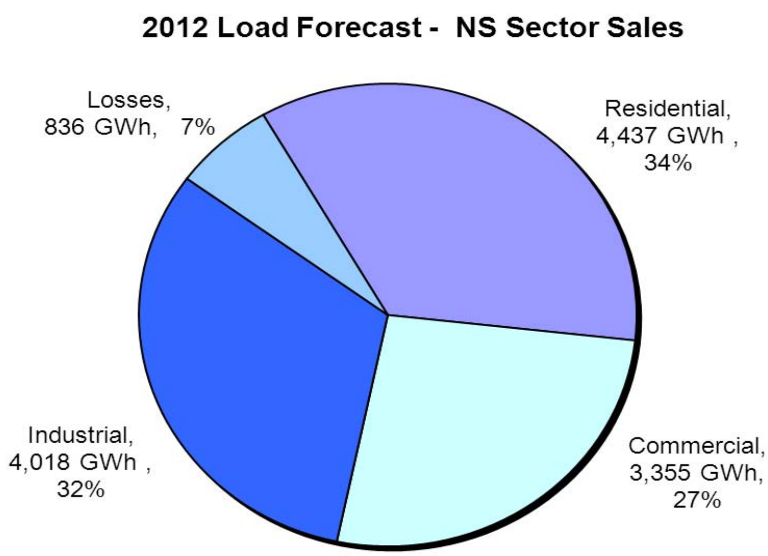
Figure 8.4 below shows the total requirement for 2012 relative to past years.

Figure 8.4



The figure below shows the contribution of the load sectors and losses to the 2012 load forecast.

Figure 8.5



The following sections describe each segment in more detail.

8.4.2 Residential Sector

The residential sector includes year-round and seasonal households, non-commercial farm use, and residential customers served by municipal utilities. We expect 2012 residential sales to make up 34 percent of in-province energy requirements.

Our residential forecast uses an econometric model that incorporates some end-use information. One of the variables projects household appliance load based on average appliance use, maturity, efficiency improvements, market penetration, and growth in the number of customers. It also uses the number of electric heating customers and expected heating degree-days for the year to determine space heating loads. Figure 8.6 shows the historical forecast accuracy for this sector, without adjustment for weather effects.

Figure 8.6

Residential Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
2000	3,636	3,672	1.0
2001	3,776	3,741	-0.9
2002	3,904	3,829	-1.9
2003	3,958	4,011	1.3
2004	4,107	4,114	0.2
2005	4,201	4,114	-2.1
2006	4,267	3,979	-6.7
2007	4,327	4,218	-2.5
2008	4,303	4,232	-1.6
2009	4,254	4,318	1.5
2010	4,153	4,216	1.5

The residential model includes detailed analysis of electric space and water heating loads. It estimates market penetration rates based on the relative price of electricity and heating oil (using recent and forecast commodity price changes). For the 2012 test year, the model predicts that approximately 30 percent of Nova Scotia residential customers will use electric space heating, up from 29 percent in 2010, and 60 percent will use electric water heating.

The residential econometric model uses sales of consumer goods as a primary economic indicator. Sales of consumer goods represent the cumulative total value of all retail goods sold in the Province, measured in millions of constant dollars. We expect this figure to grow by 0.8 percent in 2011 and 1.6 percent in 2012.

Residential load has grown at an average annual rate of 0.5 percent over the last five years or 0.8 percent when adjusted for weather effects**.**

8.4.3 Commercial Sector

The commercial sector includes restaurants, theatres, retail stores, banks, office buildings, malls, schools, and street and traffic lights. We expect commercial sales in 2012 to make up 27 percent of in-province energy requirement.

The load forecast for this sector uses an econometric model that relates commercial customer consumption to GDP, disposable income, residential sector load growth, and prior commercial load levels. Universities, hospitals, and large firms with commercial operations in Nova Scotia depend heavily on the strength of the provincial economy and the level of government expenditures. We also survey Large General rate customers, and include individual forecasts for them in our commercial sector forecast. Commercial load has grown at an average annual rate of 0.5 percent over the last five years or 0.6 percent when adjusted for weather effects**.**

Figure 8.7 shows the historical forecast accuracy for this sector, without adjustment for weather effects.

Figure 8.7

Commercial Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
2000	2,871	2,829	-1.4
2001	2,951	2,959	0.3
2002	3,075	2,996	-2.6
2003	3,091	3,091	0.0
2004	3,197	3,188	-0.3
2005	3,255	3,223	-1.0
2006	3,340	3,211	-3.9
2007	3,345	3,343	-0.1
2008	3,345	3,327	-0.5
2009	3,449	3,320	-3.7
2010	3,319	3,305	-0.4

8.4.4 Industrial Sector

The industrial sector includes customers who manufacture finished goods, or who process material to make a product of higher value. This includes fish plants, pulp and paper mills, mines, tire manufacturers, and furniture and clothing manufacturers. In 2012, we forecast industrial sales to make up 32 percent of in-province energy requirements.

To develop a load forecast for this sector, we use a combination of econometric modeling and large customer load trends and surveys. Econometric models for small and medium industrial classes relate electricity consumption to GDP. For the large industrial classes, which exert a substantial impact on overall load, surveys provide an effective basis for forecasting. These classes consist of relatively few customers spanning a variety of industries. Factors external to Nova Scotia, such as foreign exchange rates and international demand for their products, can exert a heavy influence on them. Because customer surveys can capture this information more effectively, we use surveys to develop large customer forecasts. Unplanned plant or production changes within this large customer group add significantly to the uncertainty of the load forecast.

The large industrial forecast also takes account of economic conditions, changes in technology and end-uses, planned production changes, shutdowns, and changes in the electric intensity of processes. Industrial load has declined at an average annual rate of 1.4 percent over the last five years.

Figure 8.8 shows historical forecast accuracy for this sector. Because weather has little influence on industrial sales, we do not use weather normalization in these forecasts. In 2009, economic conditions led to temporary shutdowns of some large industrial customers, and reduced production for many others. This reduced energy consumption for this sector, which is the main cause of the 14.7 percent variance from forecast.

Figure 8.8

Industrial Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
2000	3,806	3,930	3.3
2001	4,020	3,873	-3.7
2002	4,008	3,799	-5.2
2003	3,899	4,046	3.8
2004	4,120	4,212	2.2
2005	4,339	4,215	-2.9
2006	4,363	2,888	-33.8*
2007	4,388	4,207	-4.1
2008	4,300	4,161	-3.2
2009	4,289	3,658	-14.7
2010	4,117	3,932	-4.5

*** -** a major plant was closed for several months in 2006

8.4.5 Exports

Whenever economically and technically feasible, NS Power sells energy to customers outside Nova Scotia, usually during periods of low in-province demand. The margin on these sales contributes to our annual fixed costs, thereby reducing the revenue required from in-province customers. The forecast method for exports is described in Section 2.

Figure 8.9 shows export sales over the years 2000 to 2010 and forecasts for 2011 and 2012. We forecast export sales of 33.9 GWh in 2012. Associated losses of 1.0 GWh bring the total export requirement to 34.9 GWh, which is the figure we use in the 2012 test year.

Figure 8.9

Export Sales		
Year	**GWh**	**Change yr/yr**
2000	170	-14
2001	304	134
2002	489	185
2003	301	-188
2004	167	-134
2005	136	-31
2006	384	248
2007	59	-325
2008	24	-35
2009	18	-6
2010	6	-12
2011F	158	152
2012F	34	-124

8.4.6 Line Losses

The percentage of energy lost in delivery varies with volume, delivery voltage, temperature, and line impedance. Overall, we forecast delivery losses at 6.6 percent of the 2012 net in-province energy requirement.

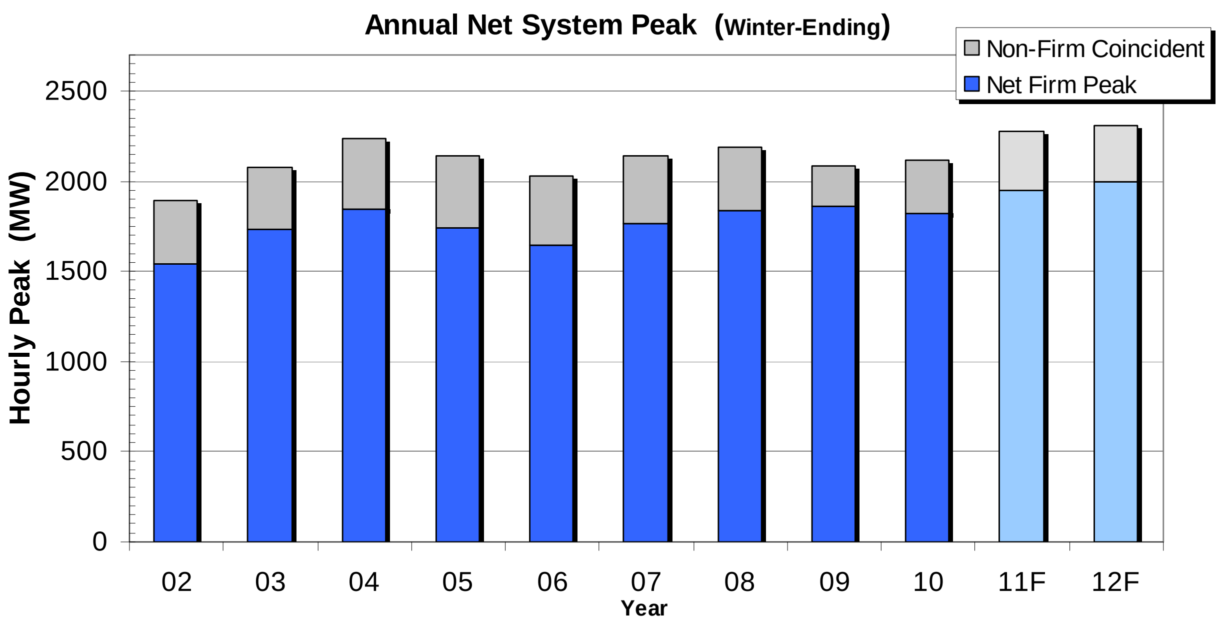
8.5 2011 Peak Demand Forecast

8.5.1 System Peak

System peak is defined as the highest average demand over a single hour experienced in a calendar year.

The hourly peak demand during the winter of 2009/2010 was 2,114 MW. It occurred in February. This was 124 MW lower than the previous record of 2,238 MW, set in January 2004. The lower peak in 2009 resulted from differences in temperature and large customer behaviour.

Figure 8.10



The forecast peak for 2012 is 2,308 MW. We base this forecast on a variety of information including industrial customer load and typical winter temperatures, and we use this value for rate-making purposes.

8.5.2 Non-Firm Coincident Peak

Certain industrial customers who meet specific criteria may contract to permit Nova Scotia Power to interrupt their electricity supply on short notice in order to meet any necessary emergency peak reductions critical to system stability. In return for this flexibility, they pay a lower rate. Electric load of this type is called “non-firm”.

One effective measure of non-firm load is the amount of electricity we are permitted to interrupt during maximum system load. We track these “non-firm coincident peaks” each month. They typically range between 300 MW and 350 MW.

Because we expect current non-firm customers to continue taking this service, we forecast non-firm coincident peak to remain near its current level.

8.5.3 Total Coincident Firm Peak

"Total Coincident Firm Peak" is the demand at the time of system peak caused by non-interruptible (firm) customer classes (such as residential, small general, etc.). It excludes demand attributable to the non-firm customer classes described in the previous section. Since the non-interruptible group includes many customers who use electric space heating, the firm peak varies substantially with weather.

In February 2010, the firm peak was 1,820 MW and we forecast a peak of 2,000 MW for 2012, based on typical winter temperatures.

9.0 COST OF SERVICE

At its most basic level, a General Rate Application has two steps. First, the Board must determine how much it will cost to produce and distribute Nova Scotia's total electricity requirements, using the lowest-cost method of generation, and allowing a fair rate of return on the money shareholders have invested in NS Power. Second, the Board must determine how much of this total revenue requirement should come from each customer class.

This section and the two sections that follow, deal with the second step.

Many factors bear on the cost of providing electricity to different categories of customers. The process of allocating costs is complex, but well-established, having been examined and resolved through many previous rate applications.

In a cost of service environment, revenue to be recovered through rates is intended to reflect the costs of serving each class, as measured by the revenue-to-cost (R/C) ratio. We have determined the costs for each rate class using NS Power's Cost of Service Study (COSS) which we have prepared for the 2012 test year. We used the methodology approved by the Board with one exception. NS Power proposes to change the method of allocating depreciation costs of the existing streetlight fixtures accounted for under the unmetered class. The proposed change will more accurately reflect the direct responsibility for this cost by the streetlight customers. Anticipated changes in the operating environment, caused by a comprehensive replacement of existing fixtures with the Light Emitting Diode streetlights beginning in mid-2012, are the reasons for this change. We propose to move the capital-related costs of LED fixtures out of the Cost of Service Study, and treat them as a Below-the-Line service category. Further details regarding the proposed changes are discussed in the Revenue Section of this Application, the Unmetered Class Ratemaking Report in Appendix G, and in the COSS document SR-01.

The COSS is predicated on the revenue requirement and costs presented in financial tables, which are included in the Standardized Filing sections of this Application. The revenue requirement used in this study is reflective of costs that are forecasted to be incurred by NS Power in 2012. It does not include forecasts for the 2012 Fuel Adjustment Mechanism (FAM AA and BA). In this regard, the COSS differs from the revenue information displayed in some financial tables, which shows revenues inclusive of the FAM amounts.[39] These amounts will be determined in a separate 2011 FAM proceeding.

Amortization of NS Power Demand Side Management expenditures incurred by NS Power in 2008 and 2009, as approved for recovery through rates in 2009 (based on a 6-year amortization schedule), continues to be included in the COSS.[40] Consistent with the 2009 GRA, these amortized costs are allocated in the same way as fixed generation costs. They will be fully recovered by 2015.

The Cost of Service Study is included in this Application as SR-01. Exhibit 1 of this appendix presents class revenue-to-cost ratios under current and proposed rates.

[39] The revenue figures presented in financial tables FOR-01 and FOR-05 include revenues associated with FAM AA and BA riders. The revenue figures in table FOR-09 do not include FAM-related revenues and match those used in the COSS.
[40] DSM amortization costs are grouped within the regulatory amortization item in financial table FOR-01.

10.0 REVENUE FORECAST AND PROPOSED RATES

This section deals with a number of technical details regarding the allocation of revenue responsibilities among rate classes.

The 2012 FAM adjustment riders, designed to true-up fuel costs incurred in prior years, are not part of the rate analysis in this Application. This aligns with the way FAM (AA and BA) costs are treated from a Cost of Service Study (COSS) perspective. However, in order to provide a comprehensive view on changes in cost of power to ratepayers in 2012, we also present the combined effects of the proposed changes to the base cost rates and the preliminary forecasts of the amounts associated with annually adjusted DSM Cost Recovery Rider (DCRR), administered by Efficiency Nova Scotia Corporation (ENSC), and the FAM.

10.1 Proposed Tariff Changes Other than those Arising from Revenue Requirement

Aside from rate changes driven by an increase in revenue requirement, NS Power is proposing to change:

- certain billing provisions of the Extra Large Two-Part Real Time (ELI 2P-RTP) Rate
- wording of the billing provisions of the Large Industrial Rate (LIR) concerned with the availability of this rate to its current interruptible customers
- ratemaking methodology of the Unmetered Rate Class

The details behind the proposed changes are discussed in separate appendices to this Application. The summaries are provided below.

10.1.1 Extra Large Two-Part Real Time Price Rate

NS Power is proposing to change billing provisions around setting of the Customer Baseline Load (CBL) and calculation of tier-based compensation for decremental energy. These changes are intended to address issues with the current operation of this rate, as identified by NS Power, in its annual and semi-annual ELI 2P-RTP reports. The proposed changes have no effect on the GRA-based rate setting process of this rate class. Please see Appendix H for details.

10.1.2 Large Industrial Rate

The language of the availability provisions, as captured in special condition 3 of the LIR rate and the availability clause of the Large Industrial Interruptible Rider (LIIR), does not reflect NS Power's billing practice and does not capture recent technological advances implemented by NS Power in the execution of its supply interruption program. The language of these provisions is a historical legacy of rate class changes brought into effect in 1996 when two separate rate classes, large industrial firm and large industrial interruptible, with 2,000 kVA minimum demand requirement each, were combined into a new single LIR class. The newly created LIR class allowed its customers to contract for both firm and interruptible power, without necessarily having to adhere to the 2,000 kVA load requirement under both firm and interruptible load nominations at the same time. The interruptible rider section of the LIR tariff has a 2,000 kVA billing demand-based availability clause, mimicking that of its host LIR tariff, without clearly indicating whether it is the interruptible load that must be in excess of the 2,000 kVA requirement or the total load of the LIR customer who nominated a fraction of its load as interruptible.

Several LIR interruptible customers today have interruptible load falling below the 2,000 kVA threshold. Further, the total combined firm and interruptible load of some of these customers also falls below the 2,000 kVA threshold. The automated dialling system[41] used by NS Power for the purposes of requesting load interruptions of LIIR customers since 2006 allows for effective integration of these smaller interruptible loads into the Control Centre Operations. NS Power relies today on the compliance of these customers with interruption requests to maintain balanced supply of power on its system.

Consequently, NS Power proposes to grandfather into the rate all those customers, who contract a portion or total of their load for interruptible power, however no longer meet the 2,000 kVA requirement. This is accomplished by the proposed wording changes to special condition 3 of the LIR tariff. Further, the wording of "a minimum regular billing demand of 2,000 kVA" in the availability clause in the LIIR section is proposed to be replaced with "a minimum regular billing demand, as determined by NS Power to add value to the interruptible program", to align tariff language with the current rate classification practice of the company.

10.1.3 Unmetered Class

NS Power has been advised by the Provincial Government that in 2011, the company will be mandated to begin a large-scale deployment of Light Emitting Diode (LED) based streetlights, which will replace the Mercury Vapour (MV), Low Pressure Sodium (LPS) and High Pressure Sodium (HPS) streetlights that are currently being used. The deployment is expected to start in 2012, and last approximately five years. The LED project will change the static streetlight operating environment, which gave rise to the current streetlight ratemaking methodology. In the next few years the net plant value of streetlights is expected to increase significantly while the amount of electricity used to

[41] NS Power uses a service provider which uses an automated dialling system.

power these fixtures is expected to go down. NS Power is proposing changes to the ratemaking methodology of the unmetered class to appropriately recover the costs associated with this mandated program.

These developments will render the current, embedded cost-based, ratemaking methodology inappropriate and unsustainable. NS Power proposes to align rates for electric power, fixture maintenance and fixture capital with costs. To ensure transparency in the ratemaking treatment of the LED capital costs and to find a suitable pricing platform for the treatment of an incremental, rather than embedded, cost approach to pricing of LED-related capital costs, NS Power proposes to take these costs out of the COSS-based Unmetered Class and place them Below-the-Line to form an LED category of their own. NS Power proposes that these rates be set in the GRA. The approach would be the same as that used for setting miscellaneous charges.

The LED deployment brings into focus the recovery of costs associated with early retirements, or sacrificed asset life, of non-LED streetlight fixtures, as well as the associated disposal costs (or salvage value). NS Power proposes that these costs be recovered from all full service, non-LED streetlight customers at the time of their conversion to LED, regardless whether the customers continue to purchase these full services from NS Power after the conversion. The proposed approach is reflective of a cost causation principle and ensures that the costs associated with the sacrificed life of the existing streetlight assets are recovered from the customers.

10.2 Rate-setting Process Overview

From the perspective of revenue inputs used in this GRA rate setting process, NS Power's rates fall into four revenue categories:

1) Above-the-Line Electric Service rates (ATL) which are changed through revenue requirement proceedings of a GRA, or in the absence of a GRA, through the FAM adjustment process which allows re-setting of the Base Cost of Fuel in ATL rates every second year. The ATL rates are developed according to the Board-approved Cost of Service and Rate Design methodology. Most of NS Power's customers are billed under ATL rates. From a rate setting perspective, the ELI 2P-RTP rate is considered an ATL rate even though from an operational perspective it is a Below-the-Line rate.[42]

2) Below-the-Line electric service rates (BTL), excluding the ELI 2P-RTP rate. All of these rates, except Mersey Additional Energy (MAE), are set annually based on pre-approved formulae and/or methodology. At the customer's choice the MAE load can be billed under the ATL rate of a Large Industrial Rider or at the BTL rate of Generation Replacement and Load Following (GRLF).

3) Miscellaneous service rates applicable to non-electric services such as customer connections, equipment rentals or wiring inspections.

4) Beginning with this Application Capital Costs of LED streetlights.

The 2012 GRA rate-setting process, under the assumption that the MAE customer's choice of rate will be a GRLF rate, consists of two steps:

[42] NSPI – Establish a Rate to Replace NSPI's Extra Large Industrial Interruptible Rate, UARB Decision, NSUARB-NSPI-P883, September 28, 2006, paragraphs 178-179.

1) Determine the total revenue shortfall from the 2012 revenue requirement, if no rates were to change, except for those BTL rates which are annually adjusted and the LED capital cost related rates, which will come into effect for the first time in 2012.

2) Calculate the remaining revenue increases required applicable to the ATL classes and to Miscellaneous Revenue. This is an iterative process, which requires reconciling adjustments between ATL and Miscellaneous rates.

10.3 Revenue Allocation Process and Results

The total revenue forecast for 2012, based on current ATL and Miscellaneous Service rates, projected BTL rates, inclusive of forecast Export revenues, but absent new LED streetlight rates is $1,244.5 million. Compared to the 2012 revenue requirement of $1,338.9 million, this represents a revenue shortfall of $94.4 million.[43] With the MAE rate class assumed to be priced at the GRLF rate in 2012 and the LED capital cost-related revenue of $1.3 million proposed to be placed Below-the-Line and priced using an incremental cost approach, the shortfall applicable to ATL and Miscellaneous Service Rates is $93.1.[44] The pricing assumptions behind the LED fixture services and BTL electric service classes form an important intermediate step in the determination of this shortfall.

10.3.1 Revenue Forecast of LED Fixture-related Capital Services and BTL Electric Service Rate Classes

[43] The figures of $1,244.5 and $1,338.9 million are arrived at by subtracting the forecasted FAM BA revenue of $50.2 million for 2012 from the total revenues of $1,294.7 (present rates) and $1,389.1 (proposed rates) million displayed in the financial table FOR-01.
[44] The choice of the GRLF rate under the MAE class, as opposed to the LIIR rate, eliminates the need for iterative adjustments in allocation of revenue responsibility between the ATL classes and the MAE making for simpler ratemaking calculations.

NS Power forecasts the LED fixture-related revenues to be $1.3 million. The details behind these calculations are included in the Streetlight Study in Appendix G.

The BTL electric service class revenues reflect customer uptake under the GRLF rate and Mersey Basic Contract. NS Power forecasts total sales to this BTL category to be 477.3 GWh or approximately 4 percent of total in-province sales in 2012. The forecast revenue from BTL sales is $27.2 million or 2 percent of total revenues. The details are discussed below.

10.3.1.1 Generation Replacement and Load Following Rate

The GRLF rate is designed to provide both load following and back-up service to large customers who own their own generation or otherwise qualify for the rate.

For 2012, NS Power forecasts energy sales priced under this rate at 288.3 GWh. The sales are comprised of 108.4 GWh billed directly under the GRLF class and 179.9 GWh billed under the Mersey Additional Energy Class, which permits its customer to choose between the LF or the Large Industrial Interruptible rates. The load forecast for 2012 represents a significant increase in the uptake under this rate since the last time NS Power filed its GRA in 2009 and is reflective of lower avoided fuel costs forecasted for 2011 and 2012.

GRLF revenue is determined by applying the relevant rate components to the Load Following (LF) and Generation Replacement (GR) portions of the kWh sales projected for each customer. The LF rate is based on the forecast average incremental cost of serving 25 MW of load in the 2012 test year, plus a $5/MWh adder. The GR rate is the sum of the $5/MWh adder and the actual (or quoted) marginal costs for a specified period of time when the customer's generation is out of service. NS Power estimates the rates based on the assumption that no exports are being served. The projected 2012 revenue under the GRLF rate amounts to $6.7 million and that under the MAE rate $11.2 million.

The current forecast Load Following rate for 2012 is 6.212 cents/kWh.

10.3.1.2 Mersey System Rate and Mersey Additional Energy

The Mersey System Rate is based on the 1965 Mersey Agreement, as amended. The rate is based on estimated costs which are used for tentative billing throughout the year, and is reconciled following year-end via a "thirteenth bill" or credit, depending upon the difference between actual and budgeted costs. The revenue amount forecast for 2012 is $9.3 million.

A portion of energy sold to Bowater and also covered under the Mersey Agreement is known as "Mersey Additional Energy". Bowater is entitled, in advance of each rate year, to select either GRLF or Large Industrial Interruptible Rider pricing for this load. For 2012, NS Power has assumed that this load will be priced at the Load Following Rate.

10.3.2 Allocation of Revenue Responsibilities to ATL Classes and Miscellaneous Revenues

Subtracting $27.2 million in revenue forecast from BTL classes, $1.3 million from LED capital costs and $1.0 million in revenue expected to be received from export sales from the total revenue requirement of $1,338.9 million yields a revenue shortfall of $93.1 million to be recovered from ATL and Miscellaneous Revenues. The revenue allocation process apportions $92.7 million of that amount to ATL classes and $0.4 million to Miscellaneous Revenues. The $92.7 million shortfall requires an average increase in ATL revenue of 7.7 percent.

The following section discusses the process used by NS Power in allocation of revenue responsibilities among ATL classes and Miscellaneous Revenue. 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 R/C ratios.

10.3.2.1 Revenue to Cost Ratios and Proposed Changes to ATL classes and Miscellaneous Revenue

Figure 10.1 compares projected costs to expected 2012 revenues at *present* rates (that is, ATL and Miscellaneous Revenues). The revenues of new LED fixture services are set at zero as presently there are no LED capital-related rates in effect. This comparison presents a revenue shortfall of $94.4 million between the revenue collected under present rates and the revenue required in 2012.

Figure 10.1

	R/C Ratio	% Revenue Increase	Proposed Revenue ($)
ABOVE-THE-LINE CLASSES			
Residential	**92.1%**	**0.0%**	**$564.2**
Commercial			
Small General	99.0%	0.0%	$29.4
General Demand	98.6%	0.0%	$273.2
Large General	93.5%	0.0%	$36.0
Total Commercial	98.0%	**0.0%**	**$338.6**
Industrial			
Small Industrial	93.5%	0.0%	$26.3
Medium Industrial	90.4%	0.0%	$45.0
Large Industrial	90.6%	0.0%	$70.4
ELI 2P-RTP (1)	83.2%	0.0%	$113.5
Total Industrial	**87.4%**	**0.0%**	**$255.1**
Other			
Municipal	91.0%	0.0%	$17.6
Unmetered	97.0%	0.0%	$25.3
Total Other	**94.4%**	**0.0%**	**$42.9**
Total Above-the-line classes	**92.7%**	**0.0%**	**$1,200.8**
BTL (Electric Services)		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$0.0**
Miscellaneous		**0.0%**	**$15.5**
Total Revenue		**0.0%**	**$1,244.5**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**-$94.4**

Figure 10.2 compares projected costs to expected 2012 revenues at *present* rates with the inclusion of $1.3 million for LED capital costs proposed to be treated as Below-the-Line category. This comparison now presents a revenue shortfall of $93.1 million.

Figure 10.2

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**92.2%**	**0.0%**	**$564.2**
Commercial			
Small General	99.1%	0.0%	$29.4
General Demand	98.6%	0.0%	$273.2
Large General	93.5%	0.0%	$36.0
Total Commercial	**98.1%**	**0.0%**	**$338.6**
Industrial			
Small Industrial	93.6%	0.0%	$26.3
Medium Industrial	90.4%	0.0%	$45.0
Large Industrial	90.7%	0.0%	$70.4
ELI 2P-RTP (1)	83.2%	0.0%	$113.5
Total Industrial	**87.4%**	**0.0%**	**$255.1**
Other			
Municipal	91.0%	0.0%	$17.6
Unmetered	99.7%	0.0%	$25.3
Total Other	**95.9%**	**0.0%**	**$42.9**
Total Above-the-line classes	**92.8%**	**0.0%**	**$1,200.8**
BTL (Electric Services)		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$1.3**
Miscellaneous		**0.0%**	**$15.5**
Total Revenue		**0.1%**	**$1,245.8**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**-$93.1**

Figure 10.3 presents revenue to cost ratios for ATL classes after BTL rates have been adjusted for projected 2012 costs and Unmetered Class revenue has been set at cost. This

results in a 7.7 percent average increase to all the ATL classes other than the Unmetered class.

As in the 2009 and 2007 Compliance Filings, the R/C ratio for the unmetered class has been set at 100 percent. As a result, the revenue from this class is determined at this stage without further adjustment for R/C ratios. However, in contrast to prior proceedings, the revenues associated with electric, fixture maintenance and capital services have been set at their respective costs as determined in the COSS. The Unmetered Class Cost of Service and Pricing Study Review, included in Appendix G, provides further details.

At this stage of rate development, the Small General, General, and ELI 2P-RTP classes have revenue to cost ratios outside of the 95 – 105 percent range.

Figure 10.3

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.5%**	**7.9%**	**$608.7**
Commercial			
Small General	106.9%	7.9%	$31.7
General Demand	106.4%	7.9%	$294.7
Large General	100.9%	7.9%	$38.8
Total Commercial	**105.8%**	**7.9%**	**$365.3**
Industrial			
Small Industrial	101.0%	7.9%	$28.4
Medium Industrial	97.5%	7.9%	$48.5
Large Industrial	97.8%	7.9%	$75.9
ELI 2P-RTP (1)	89.8%	7.9%	$122.4
Total Industrial	**94.3%**	**7.9%**	**$275.2**
Other			
Municipal	98.2%	7.9%	$19.0
Unmetered	100.0%	0.3%	$25.4
Total Other	**99.2%**	**3.4%**	**$44.4**
Total Above-the-line classes	**100.0%**	**7.7%**	**$1,293.5**
BTL (Electric Services)		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$1.3**
Miscellaneous		**2.5%**	**$15.9**
Total Revenue		**7.6%**	**$1,338.9**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**$0.0**

NS Power's objective in allocation of revenue responsibilities among rate classes is to ensure, by using a transparent allocation process, that the revenue to cost ratios of all rate classes fall within the 95 percent to 105 percent bandwidth. The use of this bandwidth is a long-standing regulatory practice in this jurisdiction.

Nova Scotia Power used a process of adjusting the 7.7 percent increase by rate class, such that all classes were brought within the allowable band, while at the same time providing sufficient revenue to meet the revenue requirement.

The process used is as follows:

- The Small General increase was reduced from 7.9 percent to 5.9 percent and the General class increase was reduced from 7.9 percent to 6.5 percent in order to set their revenue-to-cost ratios at 105.0 percent, reduced from 106.9 percent and 106.4 percent, respectively. This change reduces the revenue from the Small General class and General class, producing a revenue shortfall of $4.4 million as shown in Figure 10.4.

Figure 10.4

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.5%**	**7.9%**	**$608.7**
Commercial			
Small General	105.0%	5.9%	$31.1
General Demand	105.0%	6.5%	$290.9
Large General	100.9%	7.9%	$38.8
Total Commercial	**104.5%**	**6.6%**	**$360.8**
Industrial			
Small Industrial	101.0%	7.9%	$28.4
Medium Industrial	97.5%	7.9%	$48.5
Large Industrial	97.8%	7.9%	$75.9
ELI 2P-RTP (1)	89.8%	7.9%	$122.4
Total Industrial	**94.3%**	**7.9%**	**$275.2**
Other			
Municipal	98.2%	7.9%	$19.0
Unmetered	100.0%	0.3%	$25.4
Total Other	**99.2%**	**3.4%**	**$44.4**
Total Above-the-line classes	**99.7%**	**7.4%**	**$1,289.1**
BTL (Electric Services)		0.0%	**$27.2**
Exports		0.0%	**$1.0**
LED SL Capital-related Costs		N/A	**$1.3**
Miscellaneous		**2.4%**	**$15.9**
Total Revenue		**7.2%**	**$1,334.5**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**-$4.4**

- As Figure 10.5 shows, the $4.4 million shortfall is eliminated by allocating it across other classes such that R/C targets are kept, with the exception of ELI 2P-RTP.

Figure 10.5

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.9%**	**8.4%**	**$611.5**
Commercial			
Small General	105.0%	5.9%	$31.1
General Demand	105.0%	6.5%	$290.9
Large General	101.4%	8.4%	$39.0
Total Commercial	**104.6%**	**6.6%**	**$361.0**
Industrial			
Small Industrial	101.4%	8.4%	$28.5
Medium Industrial	98.0%	8.4%	$48.7
Large Industrial	98.3%	8.4%	$76.3
ELI 2P-RTP (1)	90.3%	8.4%	$123.0
Total Industrial	**94.8%**	**8.4%**	**$276.5**
Other			
Municipal	98.6%	8.4%	$19.1
Unmetered	100.0%	0.3%	$25.4
Total Other	**99.4%**	**3.6%**	**$44.4**
Total Above-the-line classes	**100.0%**	**7.7%**	**$1,293.5**
BTL (Electric Services)		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$1.3**
Miscellaneous		**2.5%**	**$15.9**
Total Revenue		**7.6%**	**$1,338.9**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**$0.0**

- Increasing the R/C ratio of the ELI 2P-RTP class to the minimum 95 percent results in a revenue surplus of $6.5 million as shown in Figure 10.6.

Figure 10.6

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.9%**	**8.4%**	**$611.5**
Commercial			
Small General	105.0%	5.9%	$31.1
General Demand	105.0%	6.5%	$290.9
Large General	101.4%	8.4%	$39.0
Total Commercial	**104.6%**	**6.6%**	**$361.0**
Industrial			
Small Industrial	101.4%	8.4%	$28.5
Medium Industrial	98.0%	8.4%	$48.7
Large Industrial	98.3%	8.4%	$76.3
ELI 2P-RTP (1)	95.0%	14.1%	$129.5
Total Industrial	**97.0%**	**10.9%**	**$283.0**
Other			
Municipal	98.6%	8.4%	$19.1
Unmetered	100.0%	0.3%	$25.4
Total Other	**99.4%**	**3.6%**	**$44.4**
Total Above-the-line classes	**100.5%**	**8.3%**	**$1,300.0**
BTL (Electric Services)		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$1.3**
Miscellaneous		**2.7%**	**$15.9**
Total Revenue		**8.1%**	**$1,345.4**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**$6.5**

- Figure 10.7 shows the result of allocating this $6.5 million surplus across all classes within the 95-105 range.

Figure 10.7

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.1%**	**7.5%**	**$606.7**
Commercial			
Small General	105.0%	5.9%	$31.1
General Demand	105.0%	6.5%	$290.9
Large General	100.6%	7.5%	$38.7
Total Commercial	**104.5%**	**6.5%**	**$360.7**
Industrial			
Small Industrial	100.6%	7.5%	$28.3
Medium Industrial	97.2%	7.5%	$48.3
Large Industrial	97.5%	7.5%	$75.7
ELI 2P-RTP (1)	95.0%	14.1%	$129.5
Total Industrial	**96.6%**	**10.5%**	**$281.8**
Other			
Municipal	97.9%	7.5%	$18.9
Unmetered	100.0%	0.3%	$25.4
Total Other	**99.1%**	**3.3%**	**$44.3**
Total Above-the-line classes	**100.0%**	**7.7%**	**$1,293.5**
Below-the-line		**0.0%**	**$27.2**
Exports		**0.0%**	**$1.0**
LED SL Capital-related Costs		**N/A**	**$1.3**
Miscellaneous		**2.5%**	**$15.9**
Total Revenue		**7.6%**	**$1,338.9**
Revenue Requirement		**0.0%**	**$1,338.9**
Revenue Shortfall/Surplus			**$0.0**

10.4 Combined 2012 Revenue Increase Effect Reflective of all known Rate Changes

At the time of preparing this Application, early in the fiscal year, NS Power did not make a projection of the FAM AA effect. However, ENSC's proposed 2012 DSM budget is known, as is the estimate of the 2012 FAM BA amount. All of the rider amounts will be approved for recovery by the Board in separate FAM and DSM processes to be held in the fall of 2011. The combined effect of the proposed rate changes in this GRA and the FAM BA and DCRR rider amounts, as measured against the 2012 revenues priced at present rates and adjusted for the 2011 rider effects of FAM AA/BA and DSM DCRR, are presented in the following table.

Please note that Figures 10.7 and 10.8 do not show the same percent increases as they are not compared to the same base revenue rates.

1 **Figure 10.8**

Combined Revenue Effect of all Rate Changes in 2012
(as Measured Against 2012 Revenues at Present Rates Adjusted for FAM and DSM Rider Effects from 2011)

Rate Classes	2012 GRA	FAM 2012 AA	FAM 2012 BA	DCRR 2012	DCRR BA 2012	Combined effect in 2012
ATL						
Residential	**7.1%**	**-1.2%**	**2.4%**	**0.5%**	**0.0%**	**8.8%**
Small General	5.5%	-1.1%	2.5%	-0.2%	0.0%	6.7%
General Demand	6.1%	-1.1%	3.0%	-0.5%	0.0%	7.5%
Large General	7.0%	-1.0%	3.6%	-2.5%	0.0%	7.1%
Total Commercial	**6.1%**	**-1.1%**	**3.0%**	**-0.7%**	**0.0%**	**7.4%**
Small Industrial	7.2%	-1.1%	3.1%	1.9%	0.0%	11.1%
Medium Industrial	7.1%	-1.0%	3.4%	1.4%	0.0%	11.0%
Large Industrial	7.2%	-1.0%	4.1%	0.4%	0.0%	10.7%
ELI 2PT - RTP	13.5%	-1.3%	4.5%	0.0%	0.0%	16.6%
Total Industrial	**10.0%**	**-1.2%**	**4.1%**	**0.6%**	**0.0%**	**13.4%**
Municipal	7.0%	-1.2%	3.5%	-0.2%	0.0%	9.1%
Unmetered	0.3%	-0.5%	1.5%	0.2%	0.0%	1.6%
Total Other	**3.2%**	**-0.8%**	**2.4%**	**0.0%**	**0.0%**	**4.8%**
Total ATL Classes	**7.3%**	**-1.1%**	**2.9%**	**0.1%**	**0.0%**	**9.2%**
BTL						
GRLF	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Mersey Additional Energy	0.0%	-1.4%	3.5%	0.1%	0.0%	2.2%
Bowater Mersey	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total BTL Classes	**0.0%**	**-0.6%**	**1.5%**	**0.0%**	**0.0%**	**0.9%**
FAM classes	7.2%	**-1.1%**	**2.9%**	**0.1%**	**0.0%**	**9.2%**
In Province Total	**7.2%**	**-1.1%**	**2.9%**	**0.1%**	**0.0%**	**9.1%**
Export	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Electric Sales	**7.2%**	**-1.1%**	**2.9%**	**0.1%**	**0.0%**	**9.1%**
Misc Revenue	**0.0%**	0.0%	0.0%	0.0%	0.0%	2.5%
Grand Total	**7.2%**	**-1.1%**	**2.9%**	**0.1%**	**0.0%**	**9.1%**

2

Detailed calculations behind the percentage increases above are provided in Appendix I.

10.5 Proposed Rates

Electric rates typically comprise:

- Demand charges ($/kVA or kW)
- Energy charges (cents/kWh)
- Customer charges ($/month)

From a pure rate design perspective, demand charges are generally intended to recover the demand-related costs of providing electric service. The energy charge is intended to recover the energy-related costs, and the customer charge is intended to recover the costs associated with customer-related activity. Due to historical revisions to the rates resulting from various regulatory proceedings, NS Power's rate components are not currently set purely in this fashion.

Consistent with the UARB's decision regarding Generic Rate Design in 2003,[45] NS Power is not proposing to increase customer charges in this Application. In addition, NS Power is not proposing changes to the interruptible and transformer ownership credits. Only demand and energy charges are proposed to change. NS Power proposes to set the energy charges for firm and interruptible services under the Large Industrial Rate at the same level. The current separation of these charges came into effect in 2009 as a result of a "temporary equalization adjustment" reached in the 2008 Settlement Agreement for the purposes of setting rates in the 2009 GRA Proceeding only.

[45] NSPI 2003 Generic Rate Design, UARB Decision, NSUARB – NSPI - P-878, August 1, 2003, paragraph 128.

The allocated revenue responsibilities by rate class, shown in Figure 10.7, form an input into calculations of rate components presented in the "Proof of Revenue" included in the standard filing sections of this Application. Figure 10.9 shows proposed rates components by class and their changes against current values.

Figure 10.9

PROPOSED INCREASES BY RATE COMPONENT					
RESIDENTIAL TARIFFS					
Domestic Service Rate		**units**	**Current Rate**	**Proposed Rate**	**% change**
Customer Charge		$/mo	10.830	10.830	0.0%
Energy Charge		¢/kWh	11.798	12.787	8.4%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	18.820	0.0%
December, January & Feb: energy charge					
	on-peak	¢/kWh	15.322	16.631	8.5%
	shoulder	¢/kWh	11.798	12.787	8.4%
	off-peak	¢/kWh	6.030	6.546	8.6%
Other months: energy charge					
	on-peak	¢/kWh	11.798	12.787	8.4%
	off-peak	¢/kWh	6.030	6.546	8.6%
COMMERCIAL TARIFFS					
Small General Rate		**units**	**Current Rate**	**Proposed Rate**	**% change**
Customer Charge		$/mo	12.650	12.650	0.0%
Energy Charge, block 1 (first 200 kWhs)		¢/kWh	13.067	13.952	6.8%
Energy Charge, block 2		¢/kWh	11.496	12.274	6.8%
General Rate					
Demand Charge		$/kW	9.034	9.618	6.5%
Energy Charge, block 1 (first 200kWh * demand)		¢/kWh	9.646	10.270	6.5%
Energy Charge, block 2		¢/kWh	6.824	7.265	6.5%
Transformer Ownership Credit		¢/kVA	(32.000)	(32.000)	0.0%
Large General Rate					
Demand Charge (Ratcheted)		$/kVA	11.000	11.827	7.5%
Energy Charge		¢/kWh	6.618	7.115	7.5%
Transformer Ownership Credit		¢/kVA	(32.000)	(32.000)	0.0%

1 **Figure 10.9 (continued)**

INDUSTRIAL TARIFFS				
Small Industrial Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge	$/kVA	6.442	6.928	7.5%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	8.426	9.061	7.5%
Energy Charge, block 2	¢/kWh	6.436	6.921	7.5%
Transformer Ownership Credit	¢/kVA	(32.000)	(32.000)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	10.369	11.150	7.5%
Energy Charge	¢/kWh	6.006	6.459	7.5%
Transformer Ownership Credit	¢/kVA	(32.000)	(32.000)	0.0%
Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	9.886	10.573	6.9%
Energy Charge to firm Customers	¢/kWh	6.067	6.432	6.0%
Energy Charge to interruptible customers		5.996	6.432	7.3%
Transformer Ownership Credit	¢/kVA	(32.000)	(32.000)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%
Extra Large Industrial Rate				
Customer Charge	$/mo	20,700.000	20,700.000	0.0%
Demand Charge (Ratcheted)	$/kVA	-	-	NA
Energy Charge	¢/kWh	6.228	7.109	14.1%
Interruptible Credit	$/kVA	-	-	NA
MUNICIPAL TARIFFS				
Municipal Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge (Ratcheted)	$/kVA	10.256	11.026	7.5%
Energy Charge	¢/kWh	6.213	6.680	7.5%
Transformer Ownership Credit	$/kVA	(32.000)	(32.000)	0.0%

11.0 MISCELLANEOUS CHARGES

Nova Scotia Power provides a variety of services to customers. Section 7 (Schedule of Charges) of the Board-approved Regulations sets out the charges for these services.[46] NS Power reviews these charges from time to time in light of changes in service delivery, cost structure, and technological advances.

Nova Scotia Power seeks to apply the average general rate of increase for Above-the-Line rates to Miscellaneous Charges. The Board approved this approach in the 2006 Rate Case.[47]

In any case where applying the average general rate increase results in a charge greater than the cost of delivering the service, we cap the charge at the estimated actual cost. A number of changes are proposed to charges associated with Regulation 7.3 and are described in Appendix J.

Miscellaneous revenue is forecasted to increase $1.4 million. As shown in PR-02, the application of the average general rate of increase for Above-the-Line rates to Miscellaneous Charges brings the rates closer to the costs of providing the service.

Nova Scotia Power requests UARB approval of these changes to miscellaneous charges as presented in PR-02 and PR-03.

[46] NSPI Tariffs & Regulations (UARB Approved), January 1, 2011, Retrieved on May 3, 2011 from http://www.nspower.ca/en/home/aboutnspi/ratesandregulations/nsuarbsapprovedregulations.aspx
[47] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 610.

12.0 A FINAL WORD

Electricity plays a crucial role in the livelihoods and lifestyles of Nova Scotians. It forms an intrinsic part of our way of life in the 21st Century. An application to increase the price of electricity is a matter of interest to every business and household in the province. We understand this, and we recognize our obligation to produce and deliver electricity safely, reliably, and efficiently—while managing the cost of doing so.

This Application takes place at a time of profound change in the way we produce electricity. Governments have mandated a transition to new, local, more renewable sources of electricity. They have done so for sound policy reasons that NS Power supports: to reduce the environmental impact of coal-based generation; to lessen our vulnerability to volatile world energy markets; to replace foreign fuel purchases with local economic activity and employment; and to preserve and enhance Nova Scotia's treasured environmental heritage.

Making such a profound change is a complex and difficult business. It requires an orderly, carefully planned transition from legacy solid-fuel plants to new renewable generation. We can't simply scrap one system and replace it overnight with the new.

Even with the addition of new renewable energy sources, much of our electricity will continue to come from plants that use coal and petcoke. They require necessary and appropriate systems to meet new limits on emissions of mercury, mercury, sulphur dioxide, and nitrogen oxide. Coal clean enough to meet these standards is harder to find and more expensive.

World fuel prices, meanwhile, remain volatile, and that volatility follows a relentless upward course. In the last three months alone, solid-fuel prices have risen by 30 percent.

This upward trend is proof that Nova Scotia's environmental leadership is not just the right policy, but the smart one. If we did not begin an orderly transition from imported, carbon-based fuels to local, cleaner, more renewable generation, we would leave ourselves and our children vulnerable to spiralling world energy prices over which we have neither control nor influence.

We believe our customers are buying a better product today than they bought three years ago. They are buying electricity that is cleaner and more sustainable. It will become even cleaner and more reliable in the years ahead.

With this Application, Nova Scotia Power seeks an order, effective January 1, 2012, approving:

a) The 2012 revenue requirement set out in this Application to enable Nova Scotia Power to recover the reasonable costs of providing service to customers and to meet its financial obligations, including provision for a just and reasonable return; and, as a consequence, the rates, charges and regulations requested in this Application.

b) A change in the Extra-Large Industrial Two-Part Real-Time Pricing tariff described in this Application.

c) Adjustments to the rates, charges, or regulations as needed to reflect decisions and directives in Nova Scotia Power-related proceedings, or as the UARB may determine in response to this Application.

d) An increase on the return on common equity from the current 9.35 percent to 9.6 percent, with a corresponding adjustment to the range of return.

e) NS Power's portion of the Point Tupper Wind Farm OM&G, financing, and depreciation costs, currently recovered through the Fuel Adjustment Mechanism, be recovered through the fixed rate component NS Power's rates, in the traditional manner.

We look forward to rigorous examination and robust discussion of the facts and arguments underpinning these requests. We have done our best to present the case with clarity that will help every interested Nova Scotian understand what's at stake and the reasons for our position, while meeting the requirements of this Board's oversight role.

Nova Scotia Renewable Energy Supply	2011	2013	2015	2020	Source	Energy
NS Electricity Sales Forecast (GWh) (Note 1)	11,603	11,558	11,328	10,635		
RES Requirement (%) (Note 2)	5%	10%	25%	40%		
Renewable Energy Requirement (GWh) (Note 3)	580	1,156	2,832	4,254		
Pre 2001 Renewable Energy (GWh)						
NSPI Hydro			970	970	NSPI	Hydro
IPP Hydro (Morgan Falls, Black River)			4	4	IPP	Hydro
IPP Biomass (Brooklyn Energy, Taylor Lumber)			157	157	IPP	Biomass
Total Pre 2001 Renewable Energy			1,131	1,131		
Post 2001 Renewable Energy - Committed (GWh)						
NSPI Wind (Existing, Nuttby, Digby) (Note 4)		261	261	261	NSPI	Wind
Port Hawkesbury Biomass Project		388	388	388	NSPI	Biomass
FPL Energy Pubnico	88	88	88	88	IPP	Wind
Confederation Power Inc.	55	57	57	57	IPP	Wind
Halifax Renewable Energy Corp.	9	9	9	9	IPP	Biogas
RESL	64	64	64	64	IPP	Wind
Shear Wind	145	169	169	169	IPP	Wind
RMS Energy	165	165	165	165	IPP	Wind
Maryvale	16	16	16	16	IPP	Wind
IPPs Distribution connected (December 19, 2008 RFP)		125	125	125	IPP	Various
Total Post 2001 Renewable Energy - Committed	542	1,342	1,342	1,342		
Total Renewable Energy Supply (GWh)	542	1,342	2,473	2,473		
Surplus / (Shortfall) (GWh) (Note 5)	(38)	186	(359)	(1,781)		
Options for 2015 and beyond Renewable Energy Supply						
Co-generation Large Scale Biomass (GWh)			170	170	IPP	Biomass
IPP and NSPI Large Scale Wind Projects (GWh)			600	600-1,500	IPP/NSPI	Wind
NSPI Co-firing (GWh)			150	150-300	NSPI	Biomass
Import Power - eg. Lower Churchill Muskrat Falls (GWh)				1,000-2,000	Import	Hydro
Community based Feed-in-Tariff (COMFIT) (GWh)			50-300	50-600	COMFIT	Various
New NSPI Small Hydro (GWh)			0-10	0-10	NSPI	Hydro
Bay of Fundy Tidal (GWh)			0-10	0-300	Various	Hydro

Notes:

1) NSPI 2011 Base Cost of Fuel FAM Forecast, August 16, 2010; NSPI 10 Year Energy and Demand Forecast, April 30, 2010.

2) RES for 2011 and 2013 are based on renewable energy sources post 2001; 2020 figure is a target only

3) Renewable energy requirement excludes any planning contingency for margin of safety with resource uncertainties

4) NSPI renewable energy not eligible for 2011 RES

5) In the event of a shortfall in 2011, additional renewable energy will be supplied with RES qualified import power

Prepared February 2011

Utility Performance Benchmarking Analysis

March 2011

energy everywhere.

NOVA SCOTIA POWER
An Emera Company

Background

- Operating Maintenance & General (OM&G) 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 OM&G 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:
  - OM&G expense as a percent of revenue
  - OM&G expense per customer
  - OM&G 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 OM&G 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 OM&G.

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. NBPower's vegetation management program and NFPower'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. • 1.2 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. • 338,100 electric customers. Former generation portfolio included 3,500 MW of capacity at 31 facilities in Canada and US.
Énergie NB Power	• NBPower is a vertically integrated electric utility. Cost of service regulation. Government owned and operated. • 380,000 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. • 467,000 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)

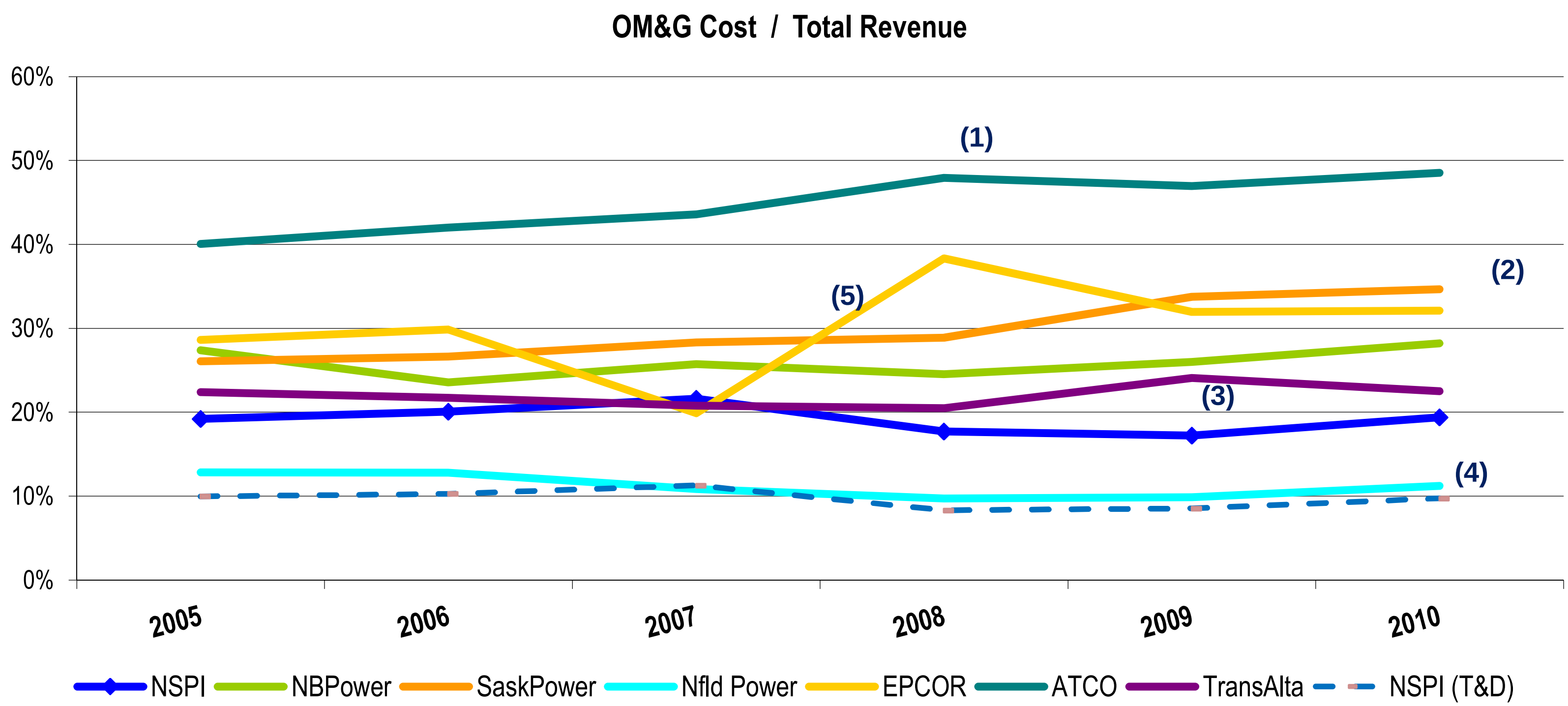
Comparables Profile

Company	Net Assets ($ Billion)	Number of Customers	Utility Type	Generation Capacity (MW)	Transmission Line (Kms)	Distribution Line (Kms)
ATCO	$10 Billion	1,294,528	Pipes, Wires, and Generation	4,885 MW	10,000 km	63,000 km
EPCOR	$1 Billion (1)	338,100 (1)	Wires Only (1)	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	243,000	Wires Only	140 MW	11,000 kms of both T&D	
NSPI	$3 Billion	489,429	Vertically Integrated	2,368 MW	5,000 km	29,000 km
SaskPower	$5 Billion	467,329	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

(1) Statistics for EPCOR in the table above include distribution and transmission business only.

OM&G 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.



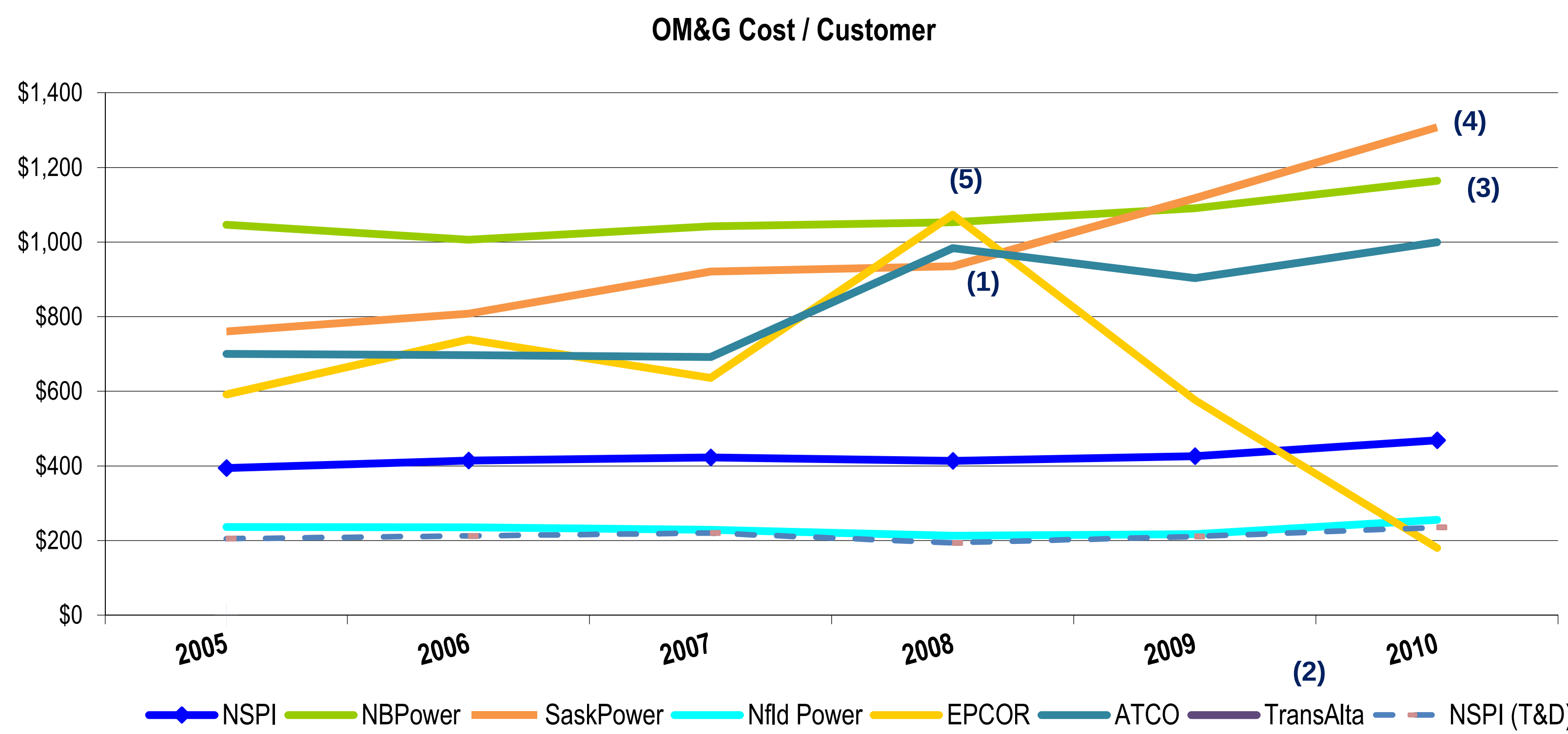
NSPI (T&D) is represented with Customer Operations, Customer Service, 50% of Corporate and Technical & Construction Service Groups and 70% of Corporate Adjustments including applied overhead credit.

OM&G Expense vs. Revenue

- Comparable trending observations:
  1) ATCO experienced increased OM&G costs relative to increases in revenues largely within its power production group that includes 69% natural gas fired plants.
  2) SaskPower has experienced increased OM&G costs at an annual average of 11% based on increased maintenance and pension benefit costs. Results for 2010 reflect forecast values as actual results are not available at this time.
  3) TransAlta's increase in plant maintenance and depressed market prices influenced the 2009 position.
  4) Newfoundland Power's OM&G expense has remained stable with an increase in 2010 associated with storm restoration with Hurricane Igor and increased pension expense. The downward trending with OM&G/Revenue is based on increased revenue recoveries associated with higher purchased power expense.
  5) EPCOR's lower operating costs in 2007 related to timing of major plant maintenance cycles is a large factor in the annual trending. Included in 2008 OM&G were major maintenance costs at the Genesee facility. The 2009 results include six months of operations related to the generation segment as it was sold to Capital Power.

OM&G 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.



energy everywhere.™ NOVA SCOTIA POWER An Emera Company

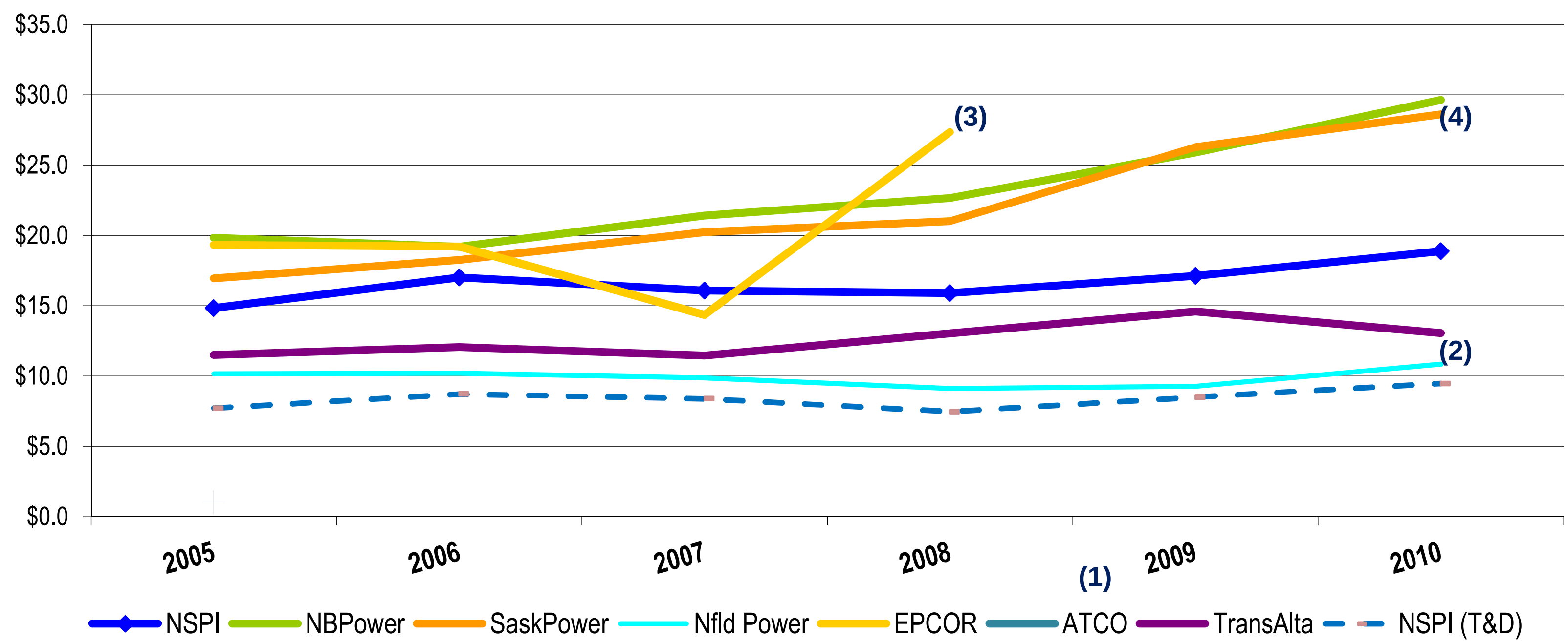
OM&G Expense per Customer

- Comparable trending observations:
  1) ATCO experienced increased OM&G costs relative to increases in customers largely within its power production group.
  2) Customer information was not available for TransAlta. As a merchant generation company, the OM&G expense per customer metric is not meaningful as it sells power to other utilities and larger users.
  3) NBPower has one of the highest OM&G expense per customer with an upward trending profile.
  4) The operating costs pressures resulting from increased maintenance and pension benefit costs at SaskPower are most evident on a per customer basis. Results for 2010 reflect forecast values as actual results are not available at this time.
  5) Timing of plant maintenance at EPCOR as noted earlier is the key factor with its results. Included in 2008 OM&G were major maintenance costs at the Genesee facility. The 2009 results include six months of operations related to the generation segment as it was sold to Capital Power.

OM&G Expense per MWh

Relative to its vertically integrated utility peers, NSPI has the lowest OM&G expense per MWh and has demonstrated a more favourable trend profile.

OM&G Cost / MWh (Total Supplied)



energy everywhere.

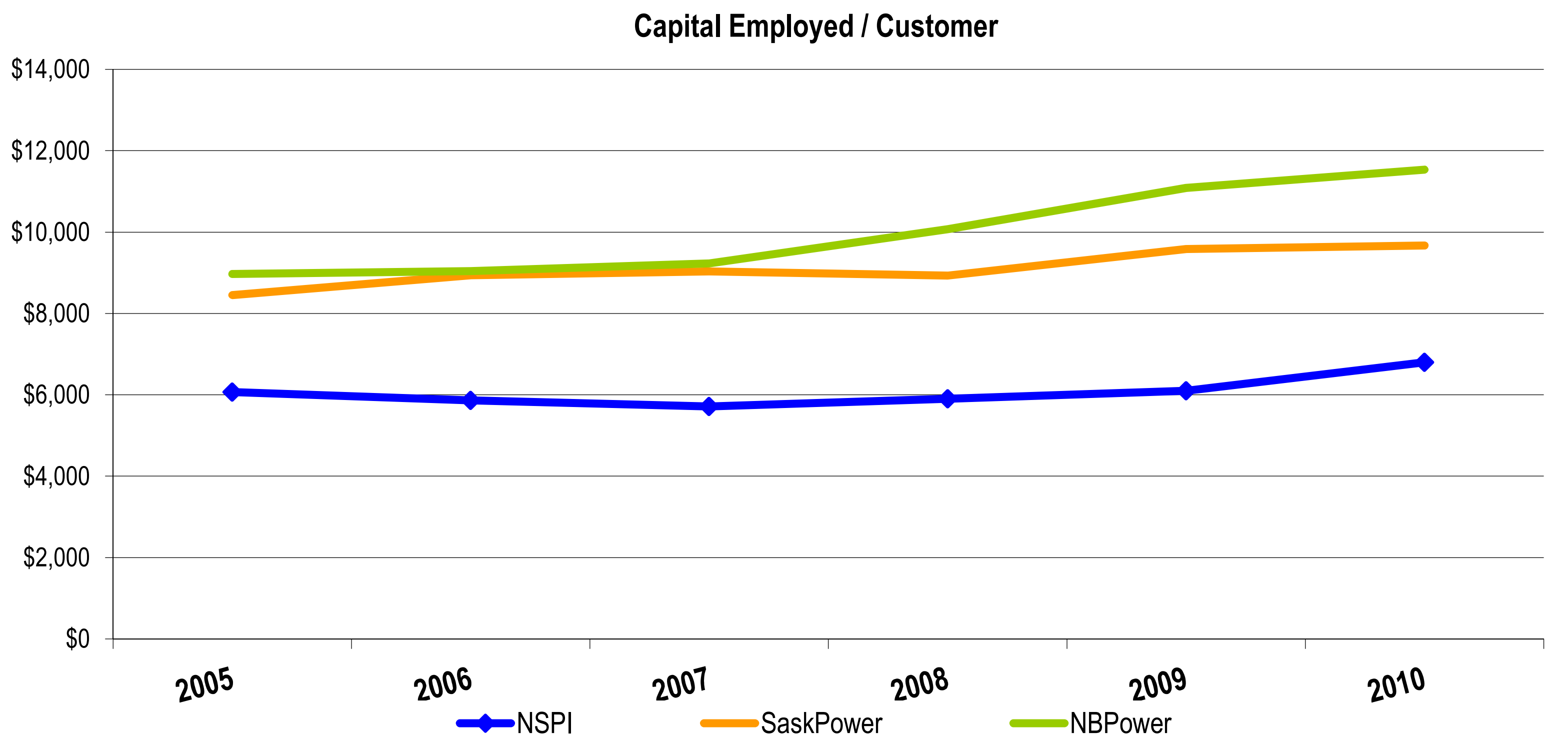
NOVA SCOTIA POWER An Emera Company

OM&G Expense per MWh

- Comparable trending observations:
  1) ATCO metrics were not included as a large portion of its operating costs include natural gas distribution operations that is benchmarked with gigajoules of natural gas. The utility segment reporting within the public financial reports includes both natural gas distribution and electricity distribution & transmission operations together.
  2) Newfoundland Power is a distribution and transmission company and therefore has a lower OM&G expense per MWh as the operating costs associated with the production of electricity is reflected in the purchased power costs.
  3) EPCOR sold its major generation assets (Capital Power) in 2009 and reported MWh's for 2009 and beyond were not available through annual financial reports.
  4) SaskPower results for 2010 reflect forecast values as actual results are not available at this time.

Capital Employed per Customer

NSPI has the lowest capital employed per customer among its vertically integrated peers. NSPI is achieving low operating costs relative to its peers without a higher level of investment in plants, wires, equipment and other assets.



The capital employed per customer was not a metric adopted in the Kaiser Report. However, it provides useful insight to asset management and operating practices when applied to directly comparable organizations.

energy everywhere.

NOVA SCOTIA POWER
An Emera Company

Notes

Appendix C
Operating Maintenance and General (OM&G) Expense
Line-by-Line Account and Variance Analysis

Redacted

NOVA SCOTIA POWER INC.
REGULATED OPERATING, MAINTENANCE AND GENERAL EXPENSES
FOR THE YEARS 2009 THROUGH 2012

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*% of Total OM&G*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Actual*	*2012 Fct. Vs. 2011 Forecast*
Executive Management	1,941	1,941	1,152	[redacted]	1,254	0.5%	(687)	102	[redacted]
Corporate Office of Secretary and General Counsel	6,761	6,761	7,052	[redacted]	8,485	3.4%	1,724	1,433	[redacted]
Corporate Finance	4,804	4,804	5,918	[redacted]	5,684	2.3%	880	(234)	[redacted]
Investor Relations, Communications and Public Affairs	1,766	1,766	2,418	[redacted]	2,486	1.0%	720	68	[redacted]
Corporate Human Resources (including Safety)	4,096	4,096	4,837	[redacted]	5,216	2.1%	1,120	379	[redacted]
Facilities and Procurement	10,139	10,139	10,266	[redacted]	8,965	3.6%	(1,174)	(1,301)	[redacted]
Information Technology	9,100	9,100	9,037	[redacted]	10,510	4.2%	1,410	1,473	[redacted]
Regulatory Affairs	5,362	5,362	5,291	[redacted]	5,859	2.4%	497	568	[redacted]
TOTAL CORPORATE GROUPS	**43,969**	**43,969**	**45,971**	[redacted]	**48,459**	19.5%	**4,490**	**2,488**	[redacted]
TECHNICAL & CONSTRUCTION SERVICES	**-**	**9,363**	**11,694**	[redacted]	**13,524**	5.4%	**4,161**	1,830	[redacted]
SUSTAINABILITY	**-**	**1,229**	**3,348**	[redacted]	**1,973**	0.8%	**744**	(1,375)	[redacted]
Renewable Planning	6,747	-	-	[redacted]	-	0.0%	-	-	[redacted]
Head Office	10,831	10,831	10,875	[redacted]	16,915	6.8%	6,084	6,040	[redacted]
Thermal Plants	62,318	62,318	65,306	[redacted]	66,671	26.8%	4,353	1,365	[redacted]
Combustion Turbines	1,109	1,109	1,218	[redacted]	1,318	0.5%	209	100	[redacted]
Hydro & Wind Energy	8,121	8,121	10,092	[redacted]	15,133	6.1%	7,012	5,041	[redacted]
Energy, Fuels and Risk Management	3,269	3,269	3,408	[redacted]	3,825	1.5%	556	417	[redacted]
TOTAL POWER PRODUCTION	**92,395**	**85,648**	**90,898**	[redacted]	**103,862**	41.8%	**18,214**	**12,964**	[redacted]
Regional Operations	15,305	15,305	22,366	[redacted]	12,992	5.2%	(2,313)	(9,374)	[redacted]
Control Center	6,829	6,829	7,142	[redacted]	8,097	3.3%	1,268	955	[redacted]
Reliability and Workforce Management and Resource Allocation	28,271	24,924	33,554	[redacted]	31,005	12.5%	6,081	(2,549)	[redacted]
Administration (incl Storm)	16,918	16,918	9,474	[redacted]	21,152	8.5%	4,234	11,678	[redacted]
TOTAL CUSTOMER OPERATIONS	**67,323**	**63,976**	**72,536**	[redacted]	**73,246**	29.5%	**9,270**	**710**	[redacted]
CUSTOMER SERVICE	**30,660**	**30,162**	**34,340**	[redacted]	**32,459**	13.1%	**2,297**	**(1,881)**	[redacted]
Pension Expense				[redacted]		-	-	-	[redacted]
Corporate Adjustments	(17,678)	(17,678)	(29,160)	[redacted]	(25,055)	-10.1%	(7,377)	4,105	[redacted]
TOTAL CORPORATE ADJUSTMENTS	**(17,678)**	**(17,678)**	**(29,160)**	[redacted]	**(25,055)**	-10.1%	**(7,377)**	**4,105**	[redacted]
TOTAL REGULATED OM&G	**216,669**	**216,669**	**229,627**	[redacted]	**248,468**	100.0%	**31,799**	**18,841**	[redacted]

Executive Management

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Act.*	*2012 Fct. Vs. 2011 Fct.*
Total Labour	***1,153***	***1,153***	***468***	[redacted]	***539***	***(614)***	***71***	[redacted]
010 Office Supplies	6	6	24	[redacted]	8	2	(16)	[redacted]
011 Travel Expense	95	95	61	[redacted]	55	(40)	(6)	[redacted]
012 Materials	1	1	4	[redacted]	-	(1)	(4)	[redacted]
013 Contracts	15	15	6	[redacted]	5	(10)	(1)	[redacted]
015 Frt, Post & Delivery	1	1	1	[redacted]	1	-	-	[redacted]
021 Telephones	12	12	10	[redacted]	8	(4)	(2)	[redacted]
028 Consulting	200	200	264	[redacted]	204	4	(60)	[redacted]
029 Membership Dues	105	105	191	[redacted]	194	89	3	[redacted]
032 Subscrpt/Info.Software	2	2	-	[redacted]	-	(2)	-	[redacted]
034 Appl. Software	1	1	-	[redacted]	-	(1)	-	[redacted]
035 Comp.Hrdwr & Op.Sftwr	1	1	12	[redacted]	-	(1)	(12)	[redacted]
037 Ext. Legal & Audit	-	-	1	[redacted]		-	(1)	[redacted]
041 Meals & Entertainment	86	86	64	[redacted]	69	(17)	5	[redacted]
042 Employee Benefits	246	246	87	[redacted]	154	(92)	67	[redacted]
056 Training & Development	2	2	5	[redacted]	5	3	-	[redacted]
066 Other Goods & Services	15	15	(46)	[redacted]	12	(3)	58	[redacted]
Total Non-Labour	***788***	***788***	***684***	[redacted]	***715***	***(73)***	***31***	[redacted]
Total	**1,941**	**1,941**	**1,152**	[redacted]	**1,254**	**(687)**	**102**	[redacted]

Responsibility Area Corporate Groups Executive Management	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	1,254	[redacted]	1,941	1,152
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Executive Management is responsible for providing corporate leadership and strategic direction and return to investors.		[redacted]	(687)	102
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Other Variations**		[redacted]		
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** decrease due to reduction of FTE's resulting from succession planning.			(614)	
> **Employee Benefits** decrease due to decrease in allocated pension expense			(92)	
> **Membership Dues** increase due to membership fees for Halifax Chamber of Commerce and Greater Halifax Partnership			89	
> **Other Variations**			(69)	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases				71
> **Consulting** decrease due to completion of contracted work to conduct customer surveys and produce a report of the results				(60)
> **Employee Benefits** increase due to increased pension expense				67
> **Other Variations**				24

Corporate Secretary and General Counsel

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Act.*	*2012 Fct. Vs. 2011 Fct.*
Total Labour	***1,186***	***1,186***	***1,119***	[redacted]	***1,256***	***70***	***137***	[redacted]
010 Office Supplies	13	13	13		12	(1)	(1)	
011 Travel Expense	43	43	32		62	19	30	
012 Materials	-	-	(11)		-	-	11	
013 Contracts	5	5	4		5	-	1	
015 Frt, Post & Delivery	9	9	18		15	6	(3)	
021 Telephones	12	12	16		15	3	(1)	
027 Corporate Filing Fees	100	100	75		122	22	47	
028 Consulting	-	-	327		-	-	(327)	
029 Membership Dues	26	26	27		35	9	8	
032 Subscrpt/Info.Software	15	15	17		17	2	-	
033 Rental/Mtnce equipment/software	33	33	-		20	(13)	20	
034 Appl. Software	2	2	6		-	(2)	(6)	
035 Comp.Hrdwr & Op.Sftwr	1	1	1		-	(1)	(1)	
036 Directors' Fees & Exp	608	608	739		1,010	402	271	
037 Ext. Legal & Audit	525	525	410		487	(38)	77	
038 Annual Shareholder Meeting	260	260	153		255	(5)	102	
041 Meals & Entertainment	19	19	46		45	26	(1)	
042 Employee Benefits	231	231	210		353	122	143	
043 Insurance	4,183	4,183	4,307		5,400	1,217	1,093	
056 Training & Development	20	20	8		17	(3)	9	
057 Corp. Support Transfe	(534)	(534)	(499)		(654)	(120)	(155)	
066 Other Goods & Services	4	4	34		13	9	(21)	
Total Non-Labour	***5,575***	***5,575***	***5,933***		***7,229***	***1,654***	***1,296***	
Total	***6,761***	***6,761***	***7,052***		***8,485***	***1,724***	***1,433***	

Responsibility Area Corporate Groups Corporate Secretary and General Counsel	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	8,485	[redacted]	6,761	7,052
Overview		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance Restated	2012 Forecast vs. 2010 Actual
The office of the Corporate Secretary and General Counsel provides corporate secretarial, legal and risk management (insurance and claims) services to the Company.		[redacted]	1,724	1,433
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Directors' Fees & Expenses** increase due to increased allowances per individual members		[redacted]		
> **Employee Benefits** increase due to increased pension expense				
> **Insurance** increase due to increased premiums				
> **Other variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and an additional FTE.			70	
> **Directors' Fees & Expenses** increase due to increased allowances per individual members			402	
> **Employee Benefits** increase due to increased pension expense			122	
> **Insurance** increase due to increased premiums			1,217	
> **Corporate Support Transfer** increase due to increased affiliate allocations			(120)	
> **Other variations**			33	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to additional FTE				137
> **Consulting** decrease due to paperless office project being completed in 2011				(327)
> **Directors' Fees & Expenses** increase due to higher valuation price				271
> **Annual Shareholder meeting** increase due to anticipated increased costs				102
> **Employee Benefits** increase due to increased pension expense				143
> **Insurance** increase due to increased premiums				1,093
> **External Legal and Audit** increase due to increasing costs of outsourced legal services				77
> **Corporate Support Transfer** increase due to increased affiliate allocations				(155)
> **Other variations**				92

Corporate Finance

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***3,643***	***3,643***	***4,654***	[redacted]	***4,908***	***1,265***	***254***	[redacted]
010 Office Supplies	42	42	68	[redacted]	61	19	(7)	[redacted]
011 Travel Expense	80	80	123	[redacted]	130	50	7	[redacted]
012 Materials	-	-	3	[redacted]	4	4	1	[redacted]
013 Contracts	477	477	381	[redacted]	415	(62)	34	[redacted]
015 Frt, Post & Delivery	1	1	1	[redacted]	1	-	-	[redacted]
021 Telephones	28	28	41	[redacted]	49	21	8	[redacted]
028 Consulting	1,028	1,028	1,658	[redacted]	285	(743)	(1,373)	[redacted]
029 Membership Dues	23	23	30	[redacted]	32	9	2	[redacted]
032 Subscrpt/Info.Software	27	27	62	[redacted]	65	38	3	[redacted]
033 Rental/Mtnce equipment/software	19	19	25	[redacted]	20	1	(5)	[redacted]
034 Appl. Software	6	6	8	[redacted]	3	(3)	(5)	[redacted]
035 Comp.Hrdwr & Op.Sftwr	2	2	3	[redacted]	1	(1)	(2)	[redacted]
037 Ext. Legal & Audit	296	296	832	[redacted]	330	34	(502)	[redacted]
041 Meals & Entertainment	31	31	47	[redacted]	47	16	-	[redacted]
042 Employee Benefits	788	788	876	[redacted]	1,340	552	464	[redacted]
051 Gen.Cost Recovery	(211)	(211)	(302)	[redacted]	(264)	(53)	38	[redacted]
052 Non Reg.Cost Recovery	-	-	-	[redacted]	-	-	-	[redacted]
056 Training & Development	97	97	63	[redacted]	117	20	54	[redacted]
057 Corp. Support Transfer	(1,588)	(1,588)	(2,681)	[redacted]	(1,893)	(305)	788	[redacted]
066 Other Goods & Services	15	15	26	[redacted]	33	18	7	[redacted]
Total Non-Labour	***1,161***	***1,161***	***1,264***	[redacted]	***776***	***(385)***	***(488)***	[redacted]
Total	***4,804***	***4,804***	***5,918***	[redacted]	***5,684***	***880***	***(234)***	[redacted]

Responsibility Area Corporate Groups Corporate Finance	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	5,684	[redacted]	4,804	5,918
Overview		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance Restated	2012 Forecast vs. 2010 Actual
Corporate Finance includes costs for the activities of : Finance, Corporate & Capital Accounting, Tax Planning and Compliance, Internal Audit, Security, and Treasury.		[redacted]	880	(234)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases and an additional FTE		[redacted]		
> **External Legal and Audit** decrease due to decreased costs assocated with external audit services				
> **Employee Benefits** increase due to increased pension costs allocation				
> **Corporate Support Transfer** decrease due to US GAAP conversion project nearing completion				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's			1,265	
> **Travel** increase due to increased FTE's			50	
> **Employee Benefits** increase due to increased pension costs and larger allocation			552	
> **Contracts** decrease due to contracting out to third party for Employee Common Share Purchase Plan			(62)	
> **Consulting** decrease due to US GAAP conversion project nearing completion and reduced Consulting in Internal Audit			(743)	
> **General Cost Recovery** increase due to increased charge out to Defined benefit plan			(53)	
> **Corporate Support Transfer** increase due to increased allocation out to affiliate			(305)	
> **Other Variations**			176	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases				254
> **Consulting** decrease due to US GAAP project nearing completion and recruitment fees				(1,373)
> **External Legal & Audit** decrease due to US GAAP project nearing completion				(502)
> **Employee Benefits** increase due to increased pension costs				464
> **Training & Development** increase due to increased costs of Training and Development				54
> **Corporate Support Transfers** decrease due to US GAAP project nearing completion				788
> **Other Variations**				81

Investor Relations, Communications & Public Affairs

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***621***	***621***	***925***	[redacted]	***847***	***226***	***(78)***	[redacted]
010 Office Supplies	5	5	11		5	-	(6)	
011 Travel Expense	40	40	52		51	11	(1)	
012 Materials	5	5	44		7	2	(37)	
013 Contracts	60	60	188		145	85	(43)	
014 Overtime Meals	-	-	(1)		-	-	1	
015 Frt, Post & Delivery	1	1	1		4	3	3	
021 Telephones	15	15	19		20	5	1	
028 Consulting	715	715	797		737	22	(60)	
029 Membership Dues	10	10	2		6	(4)	4	
032 Subscrpt/Info.Software	8	8	24		6	(2)	(18)	
034 Appl. Software	5	5	4		7	2	3	
035 Comp.Hrdwr & Op.Sftwr	5	5	8		10	5	2	
040 Advertising	100	100	88		365	265	277	
041 Meals & Entertainment	25	25	31		25	-	(6)	
042 Employee Benefits	137	137	177		241	104	64	
056 Training & Development	8	8	6		10	2	4	
057 Corp. Support Transfe	3	3	-		-	(3)	-	
066 Other Goods & Services	3	3	42		-	(3)	(42)	
Total Non-Labour	***1,145***	***1,145***	***1,493***		***1,639***	***494***	***146***	
Total	***1,766***	***1,766***	***2,418***		***2,486***	***720***	***68***	

Responsibility Area Corporate Groups Investor Relations and Communications & Public Affairs	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	2,486	[redacted]	1,766	2,418
Overview		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance Restated	2012 Forecast vs. 2010 Actual
Communications & Public Affairs and Investor Relations provides all public affairs, investor and government relations for the Company.		[redacted]	720	68
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to consolidation of responsibilities; elimination of some term positions.		[redacted]		
> **Employee Benefits** increase due to increased pension costs				
> **Other Variances**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to increased focus on customer communications, capital program communication, and stakeholder relationships			226	
> **Contracts** increase due to increased focus on customer communications and capital program communication			85	
> **Employee Benefits** increase due to increased pension costs			104	
> **Advertising** increase due to increased focus on customer communications, awareness regarding cost of energy and renewables			265	
> **Other Variances**			40	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** decrease due to consolidation of responsibilities; elimination of term positions except co-op student.				(78)
> **Consulting** decrease due to plans in place regarding customer communications and stakeholder engagement				(60)
> **Advertising** increase due to increased focus on customer communications, awareness regarding cost of energy and renewables				277
> **Employee Benefits** increase due to increased pension costs				64
> **Other Variations**				(135)

Human Resources

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***1,867***	***1,867***	***2,659***	[redacted]	***2,793***	***926***	***135***	[redacted]
010 Office Supplies	-	-	34	[redacted]	21	21	(13)	[redacted]
011 Travel Expense	232	232	209	[redacted]	284	52	75	[redacted]
012 Materials	122	122	177	[redacted]	186	64	9	[redacted]
013 Contracts	543	543	1,125	[redacted]	540	(3)	(585)	[redacted]
015 Frt, Post & Delivery	-	-	1	[redacted]	3	3	2	[redacted]
021 Telephones	27	27	36	[redacted]	52	25	16	[redacted]
028 Consulting	504	504	133	[redacted]	561	57	428	[redacted]
029 Membership Dues	12	12	7	[redacted]	26	14	19	[redacted]
032 Subscrpt/Info.Software	-	-	3	[redacted]	2	2	(1)	[redacted]
033 Rental/Mtnce equipment/softwar	49	49	37	[redacted]	55	6	18	[redacted]
035 Comp.Hrdwr & Op.Sftwr	-	-	13	[redacted]	5	5	(8)	[redacted]
037 Ext. Legal & Audit	167	167	51	[redacted]	123	(44)	72	[redacted]
040 Advertising	-	-	-	[redacted]	10	10	10	[redacted]
041 Meals & Entertainment	91	91	197	[redacted]	168	77	(29)	[redacted]
042 Employee Benefits	603	603	507	[redacted]	766	163	259	[redacted]
045 Pensioner Benefits	-	-	94	[redacted]	98	98	4	[redacted]
052 Non Reg.Cost Recovery	-	-	(4)	[redacted]	-	-	4	[redacted]
056 Training & Development	185	185	16	[redacted]	40	(145)	24	[redacted]
057 Corp. Support Transfe	(272)	(272)	(537)	[redacted]	(522)	(250)	15	[redacted]
059 HR Costs	-	-	-	[redacted]	-	-	-	[redacted]
066 Other Goods & Services	(34)	(34)	79	[redacted]	5	39	(74)	[redacted]
190 Misc revenue/recoveries (OM&G	-	-	-	[redacted]	-	-	-	[redacted]
Total Non-Labour	***2,229***	***2,229***	***2,178***	[redacted]	***2,423***	***194***	***245***	[redacted]
Total	***4,096***	***4,096***	***4,837***	[redacted]	***5,216***	***1,120***	***380***	[redacted]

Responsibility Area Corporate Groups Human Resources	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	5,216	[redacted]	4,096	4,837
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Human Resources team supports all NSPI employees in the areas of employee and industrial relations, training, apprenticeship, performance management, safety, pension, benefits and wellness administration, recruitment and payroll.		[redacted]	1,120	379
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to a reduction in FTE's		[redacted]		
> **Employee Benefits** increase due to increased pension expense				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's.			926	
> **Travel** increase due to increased FTE's			52	
> **Materials** increase due to increased costs and the cost of Safety materials			64	
> **Consulting** increase due to costs budgeted in Training and Development being reallocated to Consulting			57	
> **Employee Benefits** increase due to increased pension expense			163	
> **Pensioner Benefits** increase as Pension Benefits were missed as part of the 2009 GRA			98	
> **Training & Development** decrease due to reallocation of portion of expenses to Consulting			(145)	
> **Meals and Entertainment** increase due to increased FTE's.			77	
> **Corporate Support Transfers** increase due to allocation of larger budget and increased number of employees in affiliates			(250)	
> **Other Goods & Services** increase due to Defined Contribution Pension Plan administrative costs			39	
> **Other Variations**			39	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and full year of additional FTE's				135
> **Travel** increase due to increase in travel related costs and additional FTE's				75
> **Contracts** decrease due to reallocation of costs between Contracts and Consulting and anticipated reduction in usage of external consulting/contracts as program development work will be completed in 2011				(585)
> **Consulting** increase due to reallocation of costs between Contracts and Consulting				428
> **Employee Benefits** increase due to increased pension costs				259
> **External Legal and Audit** increase due to anticipated increases costs associated with Collective Bargaining.				72
> **Other Goods and Services** decrease due to reallocation of Storm expense costs from HR to Customer Operations Administration				(74)
> **Other Variations**				69

Facilities and Procurement

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*3,892*	*3,892*	*3,960*	[redacted]	*4,913*	*1,021*	*953*	[redacted]
010 Office Supplies	5	5	1	[redacted]	15	10	14	[redacted]
011 Travel Expense	85	85	125	[redacted]	94	9	(31)	[redacted]
012 Materials	119	119	118	[redacted]	116	(3)	(2)	[redacted]
013 Contracts	1,478	1,478	1,860	[redacted]	2,787	1,309	927	[redacted]
014 Overtime Meals	1	1	1	[redacted]	1	-	-	[redacted]
015 Frt, Post & Delivery	251	251	190	[redacted]	256	5	66	[redacted]
019 Water	35	35	47	[redacted]	36	1	(11)	[redacted]
021 Telephones	38	38	54	[redacted]	48	10	(6)	[redacted]
028 Consulting	-	-	1	[redacted]	10	10	9	[redacted]
029 Membership Dues	7	7	6	[redacted]	7	-	1	[redacted]
032 Subscrpt/Info.Software	2	2	1	[redacted]	2	-	1	[redacted]
033 Rental/Mtnce equipment/software	1	1	6	[redacted]	1	-	(5)	[redacted]
034 Appl. Software	-	-	1	[redacted]	-	-	(1)	[redacted]
035 Comp.Hrdwr & Op.Sftwr	1	1	8	[redacted]	1	-	(7)	[redacted]
041 Meals & Entertainment	18	18	33	[redacted]	23	5	(10)	[redacted]
042 Employee Benefits	832	832	672	[redacted]	1,298	466	626	[redacted]
044 Energy Use (Non-Elect	101	101	55	[redacted]	211	110	156	[redacted]
046 Energy Use	383	383	353	[redacted]	-	(383)	(353)	[redacted]
050 Rent	4,089	4,089	4,179	[redacted]	90	(3,999)	(4,089)	[redacted]
051 Gen.Cost Recovery	(2,520)	(2,520)	(1,949)	[redacted]	(1,110)	1,410	839	[redacted]
052 Non Reg.Cost Recovery	(719)	(719)	(682)	[redacted]	(1,139)	(420)	(457)	[redacted]
056 Training & Development	48	48	44	[redacted]	59	11	15	[redacted]
058 Personal Equipment	13	13	8	[redacted]	13	-	5	[redacted]
061 Write-offs	300	300	(376)	[redacted]	50	(250)	426	[redacted]
062 Recoveries	-	-	(109)	[redacted]	-	-	109	[redacted]
066 Other Goods & Services	7	7	30	[redacted]	7	-	(23)	[redacted]
083 Short-term interest	946	946	1,085	[redacted]	1,201	255	116	[redacted]
091 Tax Assessment	876	876	780	[redacted]	-	(876)	(780)	[redacted]
190 Misc revenue/recoveries	(150)	(150)	(236)	[redacted]	(25)	125	211	[redacted]
Total Non-Labour	*6,247*	*6,247*	*6,306*	[redacted]	*4,052*	*(2,195)*	*(2,254)*	[redacted]
Total	*10,139*	*10,139*	*10,266*	[redacted]	*8,965*	*(1,174)*	*(1,301)*	[redacted]

Responsibility Area Corporate Groups Facilities & Procurement	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	8,965	[redacted]	10,139	10,266
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Facilities and Procurement provide related services to all NSPI operating groups. The Procurement group is involved in the sourcing of expenditures for NSPI. The Facilities group is responsible for management of all land & facilities not directly associated with the production or delivery of energy.		[redacted]	(1,174)	(1,301)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Contracts** increase due to full year of occupancy at Lower Water Street		[redacted]		
> **Employee Benefits** increase due to increased pension costs				
> **Energy Use** decrease due to full year occupancy at Lower Water Street				
> **Rent** decrease due to full year occupancy at Lower Water Street				
> **General Cost Recovery** decrease due to full year occupancy at Lower Water Street				
> **Non-regulated Cost Recovery** increase due to full year of occupancy at Lower Water Street				
> **Short term interest** increase due to increase in inventory to support increased capital spend				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additonal FTEs			1,021	
> **Contracts** increase due to move to Lower Water Street			1,309	
> **Employee Benefits** increase due to increased pension costs			466	
> **Energy Use** decrease due to full year of occupancy at Lower Water Street			(273)	
> **Rent** decrease due to full year of occupancy at Lower Water Street			(3,999)	
> **General Cost Recovery** decrease due to move to Lower Water Street			1,410	
> **Non-regulated Cost Recovery** increase due to full year of occupancy at Lower Water Street			(420)	
> **Write-offs** decrease due to writeoffs being reallocated to Corporate Adjustments in 2012			(250)	
> **Short-term Interest** increase due to increase in inventory to support increased capital spend			255	
> **Tax Assessment** decrease full year of occupancy at Lower Water Street			(876)	
> **Miscellaneous Revenue / Recoveries** decrease due to move to Lower Water Street as lost opportunity to sublease additional space			125	
> **Other Variations**			58	

Responsibility Area Corporate Groups Facilities & Procurement	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	8,965	[redacted]	10,139	10,266
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Facilities and Procurement provide related services to all NSPI operating groups. The Procurement group is involved in the sourcing of expenditures for NSPI. The Facilities group is responsible for management of all land & facilities not directly associated with the production or delivery of energy.		[redacted]	(1,174)	(1,301)
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and additonal FTEs				953
> **Contracts** increase due to move to Lower Water Street				927
> **Freight, Postage and Delivery** increase due to adjusted Frieght and Postage in 2010				66
> **Employee Benefits** increase due to increased pension costs				626
> **Energy Use** decrease due to move to Lower Water Street				(197)
> **Rent** decrease due to move to Lower Water Street				(4,089)
> **General Cost Recovery** decrease due to move to Lower Water Street				839
> **Non-regulated Cost Recovery** increase due to move to Lower Water Street				(457)
> **Write-offs** decrease due to new inventory system installed in 2010				426
> **Recoveries** decrease due to lower rebates from suppliers				109
> **Short term interest** increase due to increase in inventory to support increased capital spend				116
> **Tax Assessment** decrease due to move to Lower Water Street				(780)
> **Miscellaneous Revenue / Recoveries** decrease due to move to Lower Water Street				211
> **Other Variations**				(51)

Information Technology

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***2,502***	***2,502***	***2,535***	[redacted]	***2,822***	***320***	***287***	[redacted]
010 Office Supplies	1	1	5	[redacted]	3	2	(2)	[redacted]
011 Travel Expense	22	22	43	[redacted]	34	12	(9)	[redacted]
012 Materials	1	1	3	[redacted]	1	-	(2)	[redacted]
013 Contracts	3,212	3,212	3,006	[redacted]	3,259	47	253	[redacted]
015 Frt, Post & Delivery	-	-	1	[redacted]	2	2	1	[redacted]
021 Telephones	(3)	(3)	(61)	[redacted]	14	17	75	[redacted]
023 Data Communication Circuits	1,408	1,408	1,326	[redacted]	1,356	(52)	30	[redacted]
028 Consulting	69	69	314	[redacted]	258	189	(56)	[redacted]
029 Membership Dues	2	2	2	[redacted]	1	(1)	(1)	[redacted]
033 Rental/Mtnce equipment/software	1,781	1,781	1,924	[redacted]	2,463	682	539	[redacted]
034 Appl. Software	2	2	21	[redacted]	3	1	(18)	[redacted]
035 Comp.Hrdwr & Op.Sftwr	-	-	8	[redacted]	2	2	(6)	[redacted]
041 Meals & Entertainment	15	15	32	[redacted]	16	1	(16)	[redacted]
042 Employee Benefits	494	494	439	[redacted]	768	274	329	[redacted]
051 Gen.Cost Recovery	-	-	(9)	[redacted]	(13)	(13)	(4)	[redacted]
052 Non Reg.Cost Recovery	(443)	(443)	(601)	[redacted]	(556)	(113)	45	[redacted]
056 Training & Development	30	30	29	[redacted]	63	33	34	[redacted]
066 Other Goods & Services	7	7	20	[redacted]	14	7	(6)	[redacted]
Total Non-Labour	***6,598***	***6,598***	***6,502***	[redacted]	***7,688***	***1,090***	***1,186***	[redacted]
Total	***9,100***	***9,100***	***9,037***	[redacted]	***10,510***	***1,410***	***1,473***	[redacted]

Responsibility Area Corporate Groups Information Technology	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	10,510	[redacted]	9,100	9,037
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Information Technology department provides equipment and related support and services to all NSPI operating groups.		[redacted]	1,410	1,473
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases and sucession planning		[redacted]		
> **Contracts** increase due to cost of infrastructure outsourcing				
> **Rental / Maintenance Equipment / Software** increase due to increased costs and new application support agreements (e.g. Maximo Viryanet/Service Hub, Design Studio).				
> **Employee Benefits** increase due to increased pension costs				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and sucession planning			320	
> **Consulting** increase due to increased costs and the requirement for additional consultants to support various projects (e.g. Oracle Financials, Microsoft Office Upgrade).			189	
> **Rental / Maintenance Equipment / Software** increase due to increased costs and new application support agreements (e.g. Maximo Viryanet/Service Hub, Design Studio).			682	
> **Employee Benefits** increase due to increased pension costs			274	
> **Non-Regulated Cost Recovery** increase due to goods and services purchased on behalf of other divisions and affiliates			(113)	
> **Other Variations**			58	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and sucession planning				287
> **Contracts** increase due to cost of infrastructure for outsourcing				253
> **Telephones** expenses increase due to 2010 amounts containing a one-time credit.				75
> **Consulting** increase due to increased costs and the requirement for additional consultants to support various projects (e.g. Oracle Financials, Microsoft Office Upgrade).				(56)
> **Rental / Maintenance Equipment / Software** increase due to increased costs and new application support agreements (e.g. Maximo Viryanet/Service Hub, Design Studio).				539
> **Employee Benefits** increase due to increased pension costs				329
> **Other Variations**				46

Regulatory Affairs

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Act.*	*2012 Fct. Vs. 2011 Fct.*
Total Labour	***1,390***	***1,390***	***1,356***	[redacted]	***1,539***	***149***	***183***	[redacted]
010 Office Supplies	10	10	3		3	(7)	-	
011 Travel Expense	24	24	25		33	9	8	
012 Materials	10	10	33		11	1	(22)	
013 Contracts	-	-	-		-	-	-	
014 Overtime Meals	-	-	-		-	-	-	
015 Frt, Post & Delivery	4	4	2		3	(1)	1	
021 Telephones	11	11	12		13	2	1	
028 Consulting	2,000	2,000	1,945		2,060	60	115	
029 Membership Dues	10	10	10		11	1	1	
032 Subscrpt/Info.Software	3	3	19		-	(3)	(19)	
033 Rental/Mtnce equipment/software	-	-	-		2	2	2	
034 Appl. Software	12	12	2		16	4	14	
035 Comp.Hrdwr & Op.Sftwr	-	-	1		1	1	-	
037 Ext. Legal & Audit	1,379	1,379	1,466		1,584	205	118	
040 Advertising	40	40	59		40	-	(19)	
041 Meals & Entertainment	27	27	41		29	2	(12)	
042 Employee Benefits	307	307	244		428	121	184	
052 Non Reg.Cost Recovery	-	-	(11)		-	-	11	
056 Training & Development	40	40	18		33	(7)	15	
066 Other Goods & Services	95	95	66		53	(42)	(13)	
Total Non-Labour	***3,972***	***3,972***	***3,935***		***4,320***	***348***	***385***	
Total	***5,362***	***5,362***	***5,291***		***5,859***	***497***	***568***	

Responsibility Area Corporate Groups Regulatory Affairs	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	5,859	[redacted]	5,362	5,291
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Regulatory Affairs includes the resources responsible for regulatory compliance and management.		[redacted]	497	568
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases		[redacted]		
> **Consulting** increase due to FAM Audit-related costs				
> **External Legal & Audit** increase due to anticipated escalation in Board assessment				
> **Employee Benefits** increase due to increased pension costs				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's			149	
> **Consulting** increase due to FAM Audit processes and General Rate Application forecast in 2012			60	
> **External Legal & Audit** increase due to anticipated Board assessment increase			205	
> **Employee Benefits** increase due to increased pension costs			121	
> **Other Goods and Services** decrease due to budget reallocations			(42)	
> **Other Variations**			4	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and half year of new FTE				183
> **Consulting** increase due to General Rate Application work less non-recurring 2010 projects (e.g. Renewables projects)				115
> **External Legal & Audit** increase due to anticipated Board assessment increase				118
> **Employee Benefits** increase due to increased pension costs				184
> **Other Variations**				(32)

Technical & Construction Services

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Act.*	*2012 Fct. Vs. 2011 Fct.*
Total Labour	**-**	***7,357***	***8,140***	[redacted]	***8,955***	***1,598***	***815***	[redacted]
010 Office Supplies	-	24	42	[redacted]	33	9	(9)	[redacted]
011 Travel Expense	-	326	424	[redacted]	572	246	148	[redacted]
012 Materials	-	128	141	[redacted]	173	45	32	[redacted]
013 Contracts	-	168	640	[redacted]	530	362	(110)	[redacted]
014 Overtime Meals	-	-	1	[redacted]	1	1	-	[redacted]
015 Frt, Post & Delivery	-	22	19	[redacted]	23	1	4	[redacted]
016 Tools & Equipment	-	41	12	[redacted]	53	12	41	[redacted]
017 Chemicals	-	6	4	[redacted]	8	2	4	[redacted]
021 Telephones	-	63	162	[redacted]	114	51	(48)	[redacted]
025 Leasing	-	-	4	[redacted]	1	1	(3)	[redacted]
028 Consulting	-	307	498	[redacted]	185	(122)	(313)	[redacted]
029 Membership Dues	-	81	31	[redacted]	99	18	68	[redacted]
031 Fleet Fuel	-	12	19	[redacted]	25	13	6	[redacted]
032 Subscrpt/Info.Software	-	15	24	[redacted]	12	(3)	(12)	[redacted]
033 Rental/Mtnce equipment/software	-	92	87	[redacted]	112	20	25	[redacted]
034 Appl. Software	-	26	22	[redacted]	49	23	27	[redacted]
035 Comp.Hrdwr & Op.Sftwr	-	8	22	[redacted]	17	9	(5)	[redacted]
041 Meals & Entertainment	-	86	185	[redacted]	185	99	-	[redacted]
042 Employee Benefits	-	654	1,454	[redacted]	2,506	1,852	1,052	[redacted]
050 Rent	-	4	13	[redacted]	12	8	(1)	[redacted]
052 Non Reg.Cost Recovery	-	-	(120)	[redacted]	-	-	120	[redacted]
056 Training & Development	-	76	92	[redacted]	105	29	13	[redacted]
057 Corp. Support Transfe	-	-	(113)	[redacted]	(162)	(162)	(49)	[redacted]
058 Personal Equipment	-	16	12	[redacted]	20	4	8	[redacted]
066 Other Goods & Services	-	65	57	[redacted]	107	42	50	[redacted]
190 Misc revenue/recoveries (OM&G)	-	(214)	(178)	[redacted]	(211)	3	(33)	[redacted]
Total Non-Labour	**-**	***2,006***	***3,554***	[redacted]	***4,569***	***2,563***	***1,015***	[redacted]
Total	**-**	***9,363***	***11,694***	[redacted]	***13,524***	***4,161***	***1,830***	[redacted]

Responsibility Area Technical & Construction Services	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	13,524	[redacted]	9,363	11,694
In 2009 Technical & Construction Services replaced the former Generation Planning & Development group. The Technical and Construction Services group focuses on the execution of initiatives to further enhance reliability, asset management and operational excellence, and support for renewable, environmental transformation and providing technical support to the Power production and Customer Operations groups.		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance Restated	2012 Forecast vs. 2010 Actual
		[redacted]	4,161	1,830
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to succession planning that commenced in 2009 being realized		[redacted]		
> **Employee Benefits** increase due to increased pension costs				
> **Corporate Support Transfers** increase due to increased allocation to affiliates				
> **Other variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to FTE's added late 2009 and 2010 to support capital programs and succession planning			1,598	
> **Travel** increase due to increased FTEs, succession planning, and capital program management/oversight			246	
> **Materials** increase due to increase in materials used by the Protective Equipment Testing Center			45	
> **Contracts** increase due to increased foot and helicopter patrols for the T&D inspection program			362	
> **Consulting** decrease due to hiring of specialized FTEs			(122)	
> **Telephones** increase due to addition of FTEs			51	
> **Meals & Entertainment** increase due addition of FTEs			99	
> **Employee Benefits** increase due to increased pension costs and additional FTE's			1,852	
> **Corporate Support Transfers** increase due to increase allocation to affiliates			(162)	
> **Other Goods and Services** increase due to T&D Engineering CEA-TI project participation/funding			42	
> **Other Variations**			150	

Responsibility Area Technical & Construction Services	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	13,524	[redacted]	9,363	11,694
In 2009 Technical & Construction Services replaced the former Generation Planning & Development group. The Technical and Construction Services group focuses on the execution of initiatives to further enhance reliability, asset management and operational excellence, and support for renewable, environmental transformation and providing technical support to the Power production and Customer Operations groups.		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
		[redacted]	4,161	1,830
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to FTE's added in 2010 to support capital programs and succession planning				815
> **Travel** increase due to increased FTEs, succession planning, and capital program management/oversight				148
> **Contracts** decrease due to capital investment planning analysis in 2010				(110)
> **Consulting** decrease due to capital investment planning analysis in 2010				(313)
> **Membership Dues** increase due to anticipated government funding				68
> **Employee Benefits** increase due to increased pension costs				1,052
> **Non-Regulatory Cost Recovery** decrease as recovery not identified				120
> **Other Goods and Services** increase due to T&D Engineering CEA-TI project participation/funding				50
> **Other Variations**				-

Sustainability

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***505***	***505***	***834***	[redacted]	***754***	***249***	***(80)***	[redacted]
010 Office Supplies	5	5	14	[redacted]	15	10	1	[redacted]
011 Travel Expense	86	86	60	[redacted]	64	(22)	4	[redacted]
012 Materials	87	87	3	[redacted]	1	(86)	(2)	[redacted]
013 Contracts	84	84	-	[redacted]	-	(84)	-	[redacted]
015 Frt, Post & Delivery	3	3	-	[redacted]	-	(3)	-	[redacted]
016 Tools & Equipment	5	5	-	[redacted]	-	(5)	-	[redacted]
021 Telephones	28	28	11	[redacted]	15	(13)	4	[redacted]
025 Leasing	1	1	-	[redacted]	-	(1)	-	[redacted]
028 Consulting	235	235	2,190	[redacted]	783	548	(1,407)	[redacted]
029 Membership Dues	11	11	4	[redacted]	14	3	10	[redacted]
031 Fleet Fuel	10	10	-	[redacted]	-	(10)	-	[redacted]
032 Subscrpt/Info.Software	7	7	(8)	[redacted]	9	2	17	[redacted]
034 Appl. Software	5	5	-	[redacted]	-	(5)	-	[redacted]
035 Comp.Hrdwr & Op.Sftwr	3	3	3	[redacted]	9	6	6	[redacted]
037 Ext. Legal & Audit	-	-	7	[redacted]	32	32	25	[redacted]
041 Meals & Entertainment	28	28	14	[redacted]	18	(10)	4	[redacted]
042 Employee Benefits	269	269	170	[redacted]	216	(53)	46	[redacted]
050 Rent	8	8	-	[redacted]	-	(8)	-	[redacted]
051 Gen.Cost Recovery			(6)	[redacted]		-	6	[redacted]
052 Non Reg.Cost Recovery	-	-	-	[redacted]	-	-	-	[redacted]
056 Training & Development	17	17	10	[redacted]	7	(10)	(3)	[redacted]
057 Corp. Support Transfe	(139)	(139)	-	[redacted]	-	139	-	[redacted]
058 Personal Equipment	2	2	-	[redacted]	-	(2)	-	[redacted]
066 Other Goods & Services	(31)	(31)	42	[redacted]	36	67	(6)	[redacted]
Total Non-Labour	***724***	***724***	***2,514***	[redacted]	***1,219***	***495***	***(1,295)***	[redacted]
Total	***1,229***	***1,229***	***3,348***	[redacted]	***1,973***	***744***	***(1,375)***	[redacted]

Responsibility Area Sustainability	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	1,973	[redacted]	1,229	3,348
Sustainability consists of the former Renewable Energy group which was formerly part of Environmental Planning. The Environmental Planning, Environmental Policy, and Ambient Air Group were moved to Technical and Construction Services in 2009.		2012 Forecast vs. 2011 Forecast [redacted]	2012 Forecast vs. 2009 Compliance 744	2012 Forecast vs. 2010 Actual (1,375)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to reduced requirements expected to achieve Renewable Energy Standards (RES) Compliance.		[redacted]		
> **Consulting** increase due to third party studies on potential wind sites.				
> Other variations				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to RES Compliance efforts.			249	
> **Materials** decrease due to change in requirement			(86)	
> **Contracts** decrease due to re-allocation to Consulting			(84)	
> **Consulting** increase due to RES Compliance efforts and re-allocation of Contracts to Consulting.			548	
> **Employee Benefits** decrease due to change in labour mix.			(53)	
> **Corporate Support Transfer** decrease due to redirection of provison of services to other groups.			139	
> **Other Goods & Services** increase due to RES Compliance Efforts.			67	
> Other Variations			(36)	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** decrease due to reduced requirements expected to achieve RES Compliance.				(80)
> **Consulting** decrease due to 2010 expense for Carbon Capture and Storage not reoccuring				(1,407)
> Other Variations				112

Power Production
Head Office

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*469*	*469*	*1,010*	[redacted]	*1,001*	*532*	*(9)*	[redacted]
010 Office Supplies	5	5	8	[redacted]	8	3	-	[redacted]
011 Travel Expense	25	25	103	[redacted]	92	67	(11)	[redacted]
012 Materials	6	6	14	[redacted]	5	(1)	(9)	[redacted]
013 Contracts	25	25	146	[redacted]	17	(8)	(129)	[redacted]
015 Frt, Post & Delivery	1	1	-	[redacted]	1	-	1	[redacted]
021 Telephones	6	6	34	[redacted]	16	10	(18)	[redacted]
028 Consulting	85	85	752	[redacted]	225	140	(527)	[redacted]
029 Membership Dues	7	7	107	[redacted]	110	103	3	[redacted]
032 Subscrpt/Info.Software	11	11	139	[redacted]	179	168	40	[redacted]
034 Appl. Software	2	2	30	[redacted]	-	(2)	(30)	[redacted]
035 Comp.Hrdwr & Op.Sftwr	4	4	2	[redacted]	-	(4)	(2)	[redacted]
037 Ext. Legal & Audit	650	650	2,046	[redacted]	2,036	1,386	(10)	[redacted]
041 Meals & Entertainment	6	6	40	[redacted]	14	8	(26)	[redacted]
042 Employee Benefits	9,378	9,378	7,384	[redacted]	13,632	4,254	6,248	[redacted]
052 Non-Reg Cost Recovery	-	-	(3)	[redacted]	-	-	3	[redacted]
056 Training & Development	31	31	40	[redacted]	5	(26)	(35)	[redacted]
065 By-product Sales	-	-	(1,099)	[redacted]	(503)	(503)	596	[redacted]
066 Other Goods & Services	120	120	122	[redacted]	77	(43)	(45)	[redacted]
Total Non-Labour	*10,362*	*10,362*	*9,865*	[redacted]	*15,914*	*5,552*	*6,049*	[redacted]
Total	*10,831*	*10,831*	*10,875*	[redacted]	*16,915*	*6,084*	*6,040*	[redacted]

Responsibility Area Power Production Head Office	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	16,915	[redacted]	10,831	10,875
Overview		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance	2012 Forecast vs. 2010 Actual
Head Office costs include Power Production Executive, Plant Operations and Management Information		[redacted]	6,084	6,040
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Employee Benefits** increase due to increased pension costs		[redacted]		
> **By-product sales decrease** due to uncertainty in market place				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE			532	
> **Travel** increase due to reallocation of Legal Services travel			67	
> **Consulting** increase to support standardization across the fleet			140	
> **Membership Dues** increase due to CEA membership			103	
> **Subscriptions / Information Software** increase due to service agreement for new maintenance management system			168	
> **External Legal & Audit** increase due to fuel contracts			1,386	
> **Employee Benefits** increase due to increased pension costs.			4,254	
> **By-product sales** increase due to change in market			(503)	
> **Other Variances**			(63)	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Contracts** decrease due to netting expenses against ash sales				(129)
> **Consulting** decrease due to a one time expenditure in 2010				(527)
> **Employee Benefits** increase due to increased pension costs				6,248
> **By-product sales** decrease due to uncertainty in market conditions				596
> **Other Variances**				(148)

Thermal Plants

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*39,044*	*39,044*	*39,752*	[redacted]	*44,193*	*5,149*	*4,441*	[redacted]
010 Office Supplies	84	84	91		83	(1)	(8)	
011 Travel Expense	168	168	321		231	63	(90)	
012 Materials	7,538	7,538	7,170		6,904	(634)	(266)	
013 Contracts	11,763	11,763	13,939		11,456	(307)	(2,483)	
014 Overtime Meals	206	206	144		114	(92)	(30)	
015 Frt, Post & Delivery	92	92	125		105	13	(20)	
016 Tools & Equipment	239	239	231		257	18	26	
017 Chemicals	561	561	606		776	215	170	
018 Gases	219	219	233		262	43	29	
019 Water	856	856	1,079		1,006	150	(73)	
021 Telephones	142	142	160		148	6	(12)	
028 Consulting	57	57	412		86	29	(326)	
029 Membership Dues	11	11	27		28	17	1	
030 Lubricants	191	191	272		215	24	(57)	
031 Fleet Fuel	322	322	43		47	(275)	4	
033 Rental/Mtnce equipment/software	66	66	152		124	58	(28)	
034 Appl. Software	25	25	14		24	(1)	10	
035 Comp.Hrdwr & Op.Sftwr	20	20	22		11	(9)	(11)	
041 Meals & Entertainment	104	104	212		141	37	(71)	
042 Employee Benefits			2			-	(2)	
050 Rent	-	-	41		-	-	(41)	
051 Gen.Cost Recovery	42	42	(2)		42	-	44	
055 Warranty & Service Contracts	5	5	(1)		6	1	7	
056 Training & Development	284	284	193		179	(105)	(14)	
058 Personal Equipment	182	182	236		233	51	(3)	
061 Write-offs			-			-	-	
065 By-product Sales	-	-	(2)		-	-	2	
066 Other Goods & Services	97	97	38		-	(97)	(38)	
189 Steam Sales	-	-	(204)		-	-	204	
Total Non-Labour	*23,274*	*23,274*	*25,554*		*22,478*	*(796)*	*(3,076)*	
Total	*62,318*	*62,318*	*65,306*		*66,671*	*4,353*	*1,365*	

Responsibility Area Power Production Thermal	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	66,671	[redacted]	62,318	65,306
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
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.		[redacted]	4,353	1,365
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due wage increases as well as additional FTE's for new generation offset by a reduction in overtime		[redacted]		
> **Materials** increase due to anticipated increased costs and added materials for Tufts Cove 6				
> **Contracts** increase due to anticipated increased costs and added contracts for Tufts Cove 6 and regulatory compliance.				
> **Chemicals** increase due to anticipated increased costs and Tufts Cove 6				
> **Water** increase due to proposed rate increase				
> Other Variations				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's offset by solid fuel handling costs moved to FAM			5,149	
> **Materials** decrease due to maintenance outage scope			(634)	
> **Contracts** decrease due to solid fuel handling expeneses falling under FAM which are offset by increases for Tufts Cove 6 and regulatory compliance			(307)	
> **Overtime meals** decrease due to mistake in calculation in 2009 General Rate Application.			(92)	
> **Chemicals** increase due to increased costs and additional expenses for Tufts Cove 6			215	
> **Water** increase due to rate increases			150	
> **Fleet Fuel** decrease due to coal unloading costs falling under FAM			(275)	
> **Rental and Maintenance Equipment** increase due to reallocation from Contracts			58	
> **Other Goods & Services** decrease due to miscellaneous expense			(97)	
> Other Variations			186	

Responsibility Area Power Production Thermal	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	66,671	[redacted]	62,318	65,306
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
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.		[redacted]	4,353	1,365
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases, vacancies being filled, and additional FTE's				4,441
> **Travel expense** decrease due to cost reduction effort				(90)
> **Materials** decrease due to change in maintenance outage scope in 2010				(266)
> **Contracts** decrease due to Tufts cove overrun and maintenance outage work 2010				(2,483)
> **Chemicals** increase due to Tufts Cove 6				170
> **Water** decrease due to one time expenditure in 2010				(73)
> **Consulting** decrease due to Tufts Cove 6 overrun				(326)
> **Lubricants** decrease due to increased maintenance outage work in 2010				(57)
> **Meals and Entertainment** decrease due to cost reduction effort				(71)
> **Steam Sales** decrease due to uncertainty with market				204
> **Other Variations**				(84)

Combustion Turbines

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*700*	*700*	*808*	[redacted]	*788*	*88*	*(20)*	[redacted]
						-	-	
010 Office Supplies	2	2	4		3	1	(1)	
011 Travel Expense	16	16	33		23	7	(10)	
012 Materials	129	129	109		140	11	31	
013 Contracts	207	207	166		291	84	125	
014 Overtime Meals	3	3	1		3	-	2	
015 Frt, Post & Delivery	6	6	16		7	1	(9)	
016 Tools & Equipment	7	7	2		4	(3)	2	
019 Water	-	-	1		1	1	-	
021 Telephones	7	7	7		7	-	-	
030 Lubricants	16	16	53		33	17	(20)	
033 Rental/Mtnce equipment/software	6	6	-		4	(2)	4	
035 Comp.Hrdwr & Op.Sftwr	1	1	-		-	(1)	-	
041 Meals & Entertainment	3	3	10		6	3	(4)	
056 Training & Development	3	3	1		5	2	4	
058 Personal Equipment	3	3	5		3	-	(2)	
066 Other Goods & Services	-	-	2		-	-	(2)	
Total Non Labour	*409*	*409*	*410*		*530*	*121*	*120*	
Total	*1,109*	*1,109*	*1,218*		*1,318*	*209*	*100*	

Responsibility Area Power Production Combustion Turbines	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	1,318	[redacted]	1,109	1,218
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Combustion Turbines includes all costs related with the engineering, maintenance and operation of the combustion turbines.		[redacted]	209	100
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases		[redacted]		
> **Contracts** increase due to tank inspection not included in OMG in prior years				
> Other Variances				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due wage increases and change in FTE			88	
> **Contracts** increase due to inflation and tank inspection			84	
> Other Variances			37	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Materials** increase due to inflation and timing of maintenance				31
> **Contracts** increase due to inflation and timing of maintenance				125
> Other Variances				(56)

Hydro & Wind Energy

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*5,618*	*5,618*	*5,439*	[redacted]	*6,586*	*968*	*1,147*	[redacted]
010 Office Supplies	21	21	21		21	(0)	(0)	
011 Travel Expense	114	114	200		146	32	(54)	
012 Materials	520	520	568		667	147	99	
013 Contracts	819	819	1,834		4,566	3,747	2,732	
014 Overtime Meals	17	17	9		8	(9)	(1)	
015 Frt, Post & Delivery	5	5	10		5	-	(5)	
016 Tools & Equipment	35	35	20		37	2	17	
019 Water	-	-	-		0	0	0	
021 Telephones	78	78	83		108	30	25	
028 Consulting	465	465	516		482	17	(34)	
029 Membership Dues	4	4	38		18	14	(20)	
030 Lubricants	11	11	20		15	4	(6)	
031 Fleet Fuel	214	214	163		209	(5)	46	
032 Subscrpt/Info.Software	-	-	-		-	-	-	
033 Rental/Mtnce equipment/software	38	38	23		45	7	22	
034 Appl. Software	-	-	1		0	0	(1)	
035 Comp.Hrdwr & Op.Sftwr	2	2	2		-	(2)	(2)	
041 Meals & Entertainment	55	55	94		76	21	(18)	
043 Insurance	-	-	-		123	123	123	
050 Rent	-	-	-		1,040	1,040	1,040	
056 Training & Development	29	29	22		40	11	18	
058 Personal Equipment	42	42	63		47	5	(16)	
066 Other Goods & Services	32	32	966		36	4	(930)	
083 Short-term interest	2	2	-		-	(2)	-	
091 Tax Assessment	-	-	-		861	861	861	
Total Non-Labour	*2,503*	*2,503*	*4,653*		*8,547*	*6,044*	*3,894*	
Total	*8,121*	*8,121*	*10,092*		*15,133*	*7,012*	*5,041*	

Responsibility Area Power Production Hydro & Wind Energy	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	15,133	[redacted]	8,121	10,092
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Hydro includes all costs related with the engineering, maintenance and operation of hydro generation stations. Wind Energy includes all costs related to the engineering, maintenance and operation of wind turbine generation stations.		[redacted]	7,012	5,041
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases and an additional FTE		[redacted]		
> **Contracts** increase due to in-stream tidal and adjustments for wind road maintenance				
> Other Variances				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE			968	
> **Materials** increase due to increased costs and additional wind generation			147	
> **Contracts** increase due to in-stream tidal and additional wind generation			3,747	
> **Insurance** increase due to wind generation			123	
> **Rent** increase due to wind generation			1,040	
> **Tax Assessment** increase due to wind generation			861	
> Other Variances			127	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's offset by vacancies in 2010				1,147
> **Travel expense** decrease due to severe weather in 2010				(54)
> **Materials** increase due to additional wind generation				99
> **Contracts** increase due to additional wind generation				2,732
> **Insurance** increase due to additional wind generation				123
> **Rent** increase due to additional wind generation				1,040
> **Other Goods and Services** decrease due to one time payment				(930)
> **Tax Assessment** increase due to additional wind				861
> Other Variances				25

Energy, Fuels and Risk Management

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	*2,206*	*2,206*	*2,268*	[redacted]	*2,549*	*343*	*281*	[redacted]
010 Office Supplies	10	10	5	[redacted]	8	(2)	3	[redacted]
011 Travel Expense	100	100	61	[redacted]	109	9	48	[redacted]
012 Materials	-	-	7	[redacted]	4	4	(3)	[redacted]
013 Contracts	343	343	221	[redacted]	155	(188)	(66)	[redacted]
015 Frt, Post & Delivery	1	1	1	[redacted]	-	(1)	(1)	[redacted]
016 Tools & Equipment	-	-	(1)	[redacted]	-	-	1	[redacted]
021 Telephones	25	25	31	[redacted]	58	33	27	[redacted]
028 Consulting	272	272	234	[redacted]	281	9	47	[redacted]
029 Membership Dues	58	58	4	[redacted]	7	(51)	3	[redacted]
032 Subscrpt/Info.Software	133	133	391	[redacted]	331	198	(60)	[redacted]
033 Rental/Mtnce equipment/software	-	-	-	[redacted]	77	77	77	[redacted]
034 Appl. Software	-	-	-	[redacted]	-	-	-	[redacted]
035 Comp.Hrdwr & Op.Sftwr	44	44	3	[redacted]	-	(44)	(3)	[redacted]
037 Ext. Legal & Audit	-	-	92	[redacted]	123	123	31	[redacted]
041 Meals & Entertainment	18	18	16	[redacted]	40	22	24	[redacted]
052 Non Reg.Cost Recovery	-	-	(4)	[redacted]	-	-	4	[redacted]
056 Training & Development	47	47	41	[redacted]	61	14	20	[redacted]
066 Other Goods & Services	12	12	38	[redacted]	22	10	(16)	[redacted]
Total Non-Labour	*1,063*	*1,063*	*1,140*	[redacted]	*1,276*	*213*	*136*	[redacted]
Total	*3,269*	*3,269*	*3,408*	[redacted]	*3,825*	*556*	*417*	[redacted]

Responsibility Area Power Production Energy, Fuels and Risk Management	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	3,825	[redacted]	3,269	3,408
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Energy, Fuels and Risk Management includes the resources responsible for fuel procurement, trading, management and generation dispatch.		[redacted]	556	417
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases		[redacted]		
> **Other Variances**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's			343	
> **Contracts** decrease due to reduction in fuel testing			(188)	
> **Membership Dues** decrease due to reallocation of expenses to Subscriptions/Information Software			(51)	
> **Subscriptions / Information Software** increase due to requirements of FAM forecasting and risk management			198	
> **Rental and Maintenance Equipment** increase due to upgraded dispatch software			77	
> **External Legal and Audit** increase due to FAM audit requirements			123	
> **Other Variances**			54	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and vacancies in 2010 for senior positions				281
> **Contracts** decrease due to mercury study				(66)
> **Subscriptions / Information Software** decrease due to reallocation of costs to Rental and Maintenance Equipment				(60)
> **Rental and Maintenance Equipment** increase due to reallocation of costs				77
> **Other Variances**				185

Regional Operations

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***12,956***	***12,956***	***17,598***	[redacted]	***10,325***	***(2,631)***	***(7,273)***	[redacted]
010 Office Supplies	56	56	53	[redacted]	61	5	8	[redacted]
011 Travel Expense	127	127	511	[redacted]	154	27	(357)	[redacted]
012 Materials	665	665	543	[redacted]	638	(27)	95	[redacted]
013 Contracts	858	858	2,177	[redacted]	1,050	192	(1,127)	[redacted]
014 Overtime Meals	35	35	105	[redacted]	39	4	(66)	[redacted]
015 Frt, Post & Delivery	15	15	16	[redacted]	13	(2)	(3)	[redacted]
016 Tools & Equipment	197	197	220	[redacted]	239	42	19	[redacted]
019 Water	4	4	18	[redacted]	19	15	1	[redacted]
020 Royalties/Easements/Appraisals	84	84	60	[redacted]	54	(30)	(6)	[redacted]
021 Telephones	454	454	512	[redacted]	496	42	(16)	[redacted]
028 Consulting	4	4	-	[redacted]	-	(4)	-	[redacted]
029 Membership Dues	4	4	3	[redacted]	3	(1)	-	[redacted]
033 Rental/Mtnce equipment/software	-	-	1	[redacted]	1	1	-	[redacted]
034 Appl. Software	2	2	-	[redacted]	3	1	3	[redacted]
035 Comp.Hrdwr & Op.Sftwr	3	3	2	[redacted]	5	2	3	[redacted]
040 Advertising	2	2	-	[redacted]	2	-	2	[redacted]
041 Meals & Entertainment	101	101	437	[redacted]	106	5	(331)	[redacted]
042 Employee Benefits	95	95	50	[redacted]	-	(95)	(50)	[redacted]
056 Training & Development	-	-	7	[redacted]	21	21	14	[redacted]
058 Personal Equipment	42	42	247	[redacted]	286	244	39	[redacted]
059 HR Costs	253	253	2	[redacted]	-	(253)	(2)	[redacted]
066 Other Goods & Services	241	241	452	[redacted]	362	121	(90)	[redacted]
190 Misc revenue/recoveries	(893)	(893)	(648)	[redacted]	(885)	8	(237)	[redacted]
Total Non-Labour	***2,349***	***2,349***	***4,768***	[redacted]	***2,667***	***318***	***(2,101)***	[redacted]
Total	***15,305***	***15,305***	***22,366***	[redacted]	***12,992***	***(2,313)***	***(9,374)***	[redacted]

Responsibility Area Customer Operations Regional Operations	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	12,992	[redacted]	15,305	22,366
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Regional Operations includes field related transmission and distribution line services across the province.		[redacted]	(2,313)	(9,374)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease as a result of a reduction in FTE's due mostly to retirements		[redacted]		
> **Other Variances**		[redacted]		
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** decrease as a result of a reduction in FTE's due mostly to retirements and reorganization of work force management/resource allocation functions			(2,631)	
> **Contracts** increase due to increased outsourcing costs			192	
> **Other Goods and Services** increase due to increased costs and activity.			121	
> **Other Variances**			5	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** decrease due to reduction in FTE's and storm costs being reallocated to Customer Operations Administration and reorganization of work force management/resource allocation functions				(7,273)
> **Travel expense** decrease due to reallocation of storm costs to Customer Operations Administration				(357)
> **Materials** increase in services materials				95
> **Contracts** decrease due to reallocation of storm costs to Customer Operations Administration				(1,127)
> **Overtime Meals** decrease due to reallocation of storm costs to Customer Operations Administration				(66)
> **Meals and Entertainment** decrease due to reallocation of storm costs to Customer Operations Administration				(331)
> **Employee Benefits** decrease due to reallocation of storm costs to Customer Operations Administration				(50)
> **Other Goods and Services** decrease due to anticipated reduction in activity from 2010 level				(90)
> **Miscellaneous Revenues / Recoveries** increase due to an anticipated increase in customer-driven work				(237)
> **Other Variances**				62

Control Center

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***5,174***	***5,174***	***5,329***	[redacted]	***6,025***	***851***	***696***	[redacted]
010 Office Supplies	9	9	12	[redacted]	9	-	(3)	[redacted]
011 Travel Expense	56	56	60	[redacted]	89	33	29	[redacted]
012 Materials	59	59	52	[redacted]	46	(13)	(6)	[redacted]
013 Contracts	299	299	393	[redacted]	365	66	(28)	[redacted]
014 Overtime Meals	-	-	3	[redacted]	3	3	-	[redacted]
015 Frt, Post & Delivery	3	3	5	[redacted]	5	2	-	[redacted]
016 Tools & Equipment	2	2	1	[redacted]	2	-	1	[redacted]
019 Water	-	-	-	[redacted]	-	-	-	[redacted]
020 Royalties/Easements/Appraisals	42	42	46	[redacted]	47	5	1	[redacted]
021 Telephones	84	84	82	[redacted]	91	7	9	[redacted]
023 Data Communication Circuits	321	321	353	[redacted]	410	89	57	[redacted]
028 Consulting	-	-	(69)	[redacted]	-	-	69	[redacted]
029 Membership Dues	235	235	368	[redacted]	378	143	10	[redacted]
032 Subscrpt/Info.Software	1	1	6	[redacted]	1	-	(5)	[redacted]
033 Rental/Mtnce equipment/software	261	261	69	[redacted]	108	(153)	39	[redacted]
034 Appl. Software	2	2	1	[redacted]	2	-	1	[redacted]
035 Comp.Hrdwr & Op.Sftwr	2	2	2	[redacted]	2	-	-	[redacted]
040 Advertising	4	4	-	[redacted]	4	-	4	[redacted]
041 Meals & Entertainment	19	19	37	[redacted]	39	20	2	[redacted]
042 Employee Benefits	-	-	-	[redacted]	-	-	-	[redacted]
050 Rent	112	112	113	[redacted]	125	13	12	[redacted]
055 Warranty & Service Contracts	117	117	288	[redacted]	336	219	48	[redacted]
056 Training & Development	42	42	35	[redacted]	73	31	38	[redacted]
058 Personal Equipment	2	2	2	[redacted]	16	14	14	[redacted]
059 HR Costs	-	-	-	[redacted]	-	-	-	[redacted]
066 Other Goods & Services	8	8	98	[redacted]	8	-	(90)	[redacted]
190 Misc revenue/recoveries	(25)	(25)	(144)	[redacted]	(87)	(62)	57	[redacted]
Total Non Labour	***1,655***	***1,655***	***1,813***	[redacted]	***2,072***	***417***	***259***	[redacted]
Total	***6,829***	***6,829***	***7,142***	[redacted]	***8,097***	***1,268***	***955***	[redacted]

Responsibility Area Customer Operations Control Center	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	8,097	[redacted]	6,829	7,142
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
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.		[redacted]	1,268	955
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to decrease in FTE's		[redacted]		
> **Other Variances**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due wage increases and additional FTE's as part of succession planning			851	
> **Contracts** increase due to more work required for mobile radio repairs and radio site building repairs as a result of aging equipment.			66	
> **Data Communication Circuits** increase due increase of SCADA pole-top re-closers across the province.			89	
> **Membership Dues** increase due to rising costs and additional NERC fees			143	
> **Rental / Maintenance Equipment / Software** decrease due to reduced activity since 2009			(153)	
> **Warranty & Service Contracts** increase due increase SCADA software/hardware, NERC training software and increase costs			219	
> **Miscellaneous Revenue\Recoveries** increase due to forecasted Generation Interconnection Procedure (GIP) projects			(62)	
> **Other Variances**			115	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and additional FTE's as part of succession planning				696
> **Data Communication Circuits** increase due increase of SCADA pole-top re-closers across the province.				57
> **Consulting** increase due to non-recurring credit in 2010				69
> **Other Goods and Services** decrease due to one-time charges in 2010				(90)
> **Miscellaneous Revenue\Recoveries** decrease due to forecasted Generation Interconnection Procedure (GIP) projects				57
> **Other Variances**				166

Reliability and Workforce Management and Resource Allocation

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***15,013***	***12,198***	***14,503***	[redacted]	***16,654***	***4,456***	***2,151***	[redacted]
010 Office Supplies	51	49	39	[redacted]	37	(12)	(2)	[redacted]
011 Travel Expense	476	338	335	[redacted]	254	(84)	(81)	[redacted]
012 Materials	1,522	1,479	1,553	[redacted]	1,337	(142)	(216)	[redacted]
013 Contracts	14,337	14,232	21,676	[redacted]	17,176	2,944	(4,500)	[redacted]
014 Overtime Meals	18	18	39	[redacted]	24	6	(15)	[redacted]
015 Frt, Post & Delivery	11	11	12	[redacted]	7	(4)	(5)	[redacted]
016 Tools & Equipment	85	48	31	[redacted]	34	(14)	3	[redacted]
020 Royalties/Easements/Appraisals	18	18	27	[redacted]	28	10	1	[redacted]
021 Telephones	198	180	325	[redacted]	260	80	(65)	[redacted]
025 Leasing	16	16	66	[redacted]	39	23	(27)	[redacted]
028 Consulting	42	41	68	[redacted]	62	21	(6)	[redacted]
029 Membership Dues	31	15	37	[redacted]	14	(1)	(23)	[redacted]
031 Fleet Fuel	-	-	2	[redacted]	1	1	(1)	[redacted]
032 Subscrpt/Info.Software	2	2	-	[redacted]	-	(2)	-	[redacted]
033 Rental/Mtnce equipment/software	29	16	35	[redacted]	66	50	31	[redacted]
034 Appl. Software	3	-	2	[redacted]	2	2	-	[redacted]
035 Comp.Hrdwr & Op.Sftwr	12	7	2	[redacted]	1	(6)	(1)	[redacted]
041 Meals & Entertainment	186	150	119	[redacted]	123	(27)	4	[redacted]
042 Employee Benefits	36	36	16	[redacted]	-	(36)	(16)	[redacted]
050 Rent	-	-	1	[redacted]	1	1	-	[redacted]
056 Training & Development	114	86	23	[redacted]	56	(30)	33	[redacted]
058 Personal Equipment	136	126	105	[redacted]	199	73	94	[redacted]
066 Other Goods & Services	**(306)**	(383)	(439)	[redacted]	(404)	(21)	35	[redacted]
190 Misc revenue/recoveries	(3,759)	(3,759)	(5,023)	[redacted]	(4,966)	(1,207)	57	[redacted]
Total Non-Labour	***13,258***	***12,726***	***19,051***	[redacted]	***14,351***	***1,625***	***(4,700)***	[redacted]
Total	***28,271***	***24,924***	***33,554***	[redacted]	***31,005***	***6,081***	***(2,549)***	[redacted]

Responsibility Area Customer Operations Reliability and Workforce Management and Resource Allocation	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	31,005	[redacted]	24,924	33,554
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Included in this section are costs related to reliability programming, including Vegetation Management, and Work Management and Resource Allocation. Workforce Management and Resource Allocation optimizes the planning, scheduling, and dispatch of work to Customer Operations and Customer Service personnel. Fleet Management costs are also included in this section.		[redacted]	6,081	(2,549)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to reduced number of FTE's		[redacted]		
> **Contracts** increase due to increase to fund off right-of-way tree initiative				
> **Micellaneous Revenues\Recoveries** increase due to increased forestry/make-ready work				
> **Other Variances**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and reorganization of Workforce Management and Resource Allocation functions			4,456	
> **Travel Expense** decrease due to reallocation of labour to other division			(84)	
> **Materials** decrease due to reduction in fleet maintenance			(142)	
> **Contracts** increase due to increased costs and increase to fund off right-of-way tree intiatives			2,944	
> **Telephones** increase due to increased costs and reorganization of workforce management and resource allocation functions			80	
> **Rental and Maintenance Equipment** increase due to reorganization of workforce management and resource allocation functions			50	
> **Personal Equipment** increase due to increased apprentice usage			73	
> **Miscellaneous Revenues / Recoveries** increase due to increased forestry work and make-ready rates			(1,207)	
> **Other Variances**			(89)	

Responsibility Area Customer Operations Reliability and Workforce Management and Resource Allocation	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	31,005	[redacted]	24,924	33,554
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Included in this section are costs related to reliability programming, including Vegetation Management, and Work Management and Resource Allocation. Workforce Management and Resource Allocation optimizes the planning, scheduling, and dispatch of work to Customer Operations and Customer Service personnel. Fleet Management costs are also included in this section.		[redacted]	6,081	(2,549)
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and reorganization of Workforce Management and Resource Allocation offset by reallocation of storm costs to Customer Operations Administration				2,151
> **Travel expense** decrease due to reallocation of storm costs to Customer Operations Adminsitration				(81)
> **Materials** decrease due to reduction in make-ready work and decrease in other work activities				(216)
> **Contracts** decrease due to reallocation of Storm Costs to Customer Operations Administration offset by increase to fund off right-of-way tree intiatives				(4,500)
> **Telephones** decrease due to reduction in telecommunications rate				(65)
> **Personal Equipment** increase due to increased apprentice usage and overall general increased usage				94
> **Miscellaneous Revenues** increase due to increased volume in system maintenance offset by reduction in vegetation management revenues				57
> **Other Variances**				11

Customer Operations - Administration (including Storm)

(in Thousands of $)

	2009 Compliance	*2009 Compliance Restated*	*2010 Actual*	*2011 Forecast*	*2012 Forecast*	*2012 Fct. Vs. 2009 Compliance Restated*	*2012 Fct. Vs. 2010 Act.*	*2012 Fct. Vs. 2011 Fct.*
Total Labour	***4,194***	***4,194***	***968***	[redacted]	***5,568***	***1,374***	***4,600***	[redacted]
				[redacted]				[redacted]
010 Office Supplies	9	9	4	[redacted]	6	(3)	2	[redacted]
011 Travel Expense	307	307	33	[redacted]	389	82	356	[redacted]
012 Materials	115	115	9	[redacted]	60	(55)	51	[redacted]
013 Contracts	2,246	2,246	155	[redacted]	3,157	911	3,002	[redacted]
014 Overtime Meals	40	40	-	[redacted]	72	32	72	[redacted]
015 Frt, Post & Delivery	1	1	-	[redacted]	1	-	1	[redacted]
021 Telephones	52	52	23	[redacted]	66	14	43	[redacted]
028 Consulting	43	43	556	[redacted]	228	185	(328)	[redacted]
029 Membership Dues	10	10	-	[redacted]	1	(9)	1	[redacted]
031 Fleet Fuel	2,669	2,669	2,602	[redacted]	2,637	(32)	35	[redacted]
032 Subscrpt/Info.Software	4	4	-	[redacted]	-	(4)	-	[redacted]
041 Meals & Entertainment	185	185	20	[redacted]	228	43	208	[redacted]
042 Employee Benefits	6,987	6,987	5,528	[redacted]	8,910	1,923	3,382	[redacted]
056 Training & Development	22	22	3	[redacted]	2	(20)	(1)	[redacted]
058 Personal Equipment	10	10	-	[redacted]	19	9	19	[redacted]
066 Other Goods & Services	24	24	-	[redacted]	12	(12)	12	[redacted]
190 Misc revenue/recoveries (OM&G)	-	-	(427)	[redacted]	(204)	(204)	223	[redacted]
Total Non-Labour	***12,724***	***12,724***	***8,506***	[redacted]	***15,584***	***2,860***	***7,078***	[redacted]
				[redacted]				[redacted]
Total	***16,918***	***16,918***	***9,474***	[redacted]	***21,152***	***4,234***	***11,678***	[redacted]

Responsibility Area Customer Operations Administration & Storm	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	21,152	[redacted]	16,918	9,474
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance**	**2012 Forecast vs. 2010 Actual**
Customer Operations Administration includes the costs associated with the management of the customer operations functions. For tracking and control purposes, storm costs for the entire province are forecasted in Customer Operations.		[redacted]	4,234	11,678
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** increase due to wage increases and increased storm costs		[redacted]		
> **Travel expense** increase due to increased storm costs		[redacted]		
> **Contracts** increase due to increased storm costs		[redacted]		
> **Fleet Fuel** increase due to increased costs		[redacted]		
> **Meals and Entertainment** increase due to increased storm costs		[redacted]		
> **Employee Benefits** increase due to increased pension costs		[redacted]		
> **Other Variances**		[redacted]		
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases and increased storm costs offset by reduction in FTE's			1,374	
> **Travel expense** increase due to increased storm costs			82	
> **Contracts** increase due to increased costs and increased storm costs			911	
> **Consulting** increase due to increased costs and increased storm costs			185	
> **Employee Benefits** increase due to increased pension costs			1,923	
> **Miscellaneous Revenues** increase due to anticipated increase in other revenues not allocated to other cost centers			(204)	
> **Other Variances**			(37)	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases, increased storm costs, and reallocation of Storm costs from other divisions				4,600
> **Travel expense** increase due to increased storm costs				356
> **Materials** increase due to increased storm costs				51
> **Contracts** decrease due to increased storm costs and reallocation of Storm costs from other cost centers				3,002
> **Overtime meals** increase due to increased storm costs				72
> **Consulting** decrease due to reduced activity				(328)
> **Meals & Entertainment** increase due to increased storm costs				208
> **Employee Benefits** increase due to increased pension costs				3,382
> **Miscellaneous Revenues** decrease due to revenue realized in 2010 not likely to occur in 2012				223
> **Other Variances**				112

Customer Service

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***16,682***	***16,029***	***17,099***	[redacted]	***17,517***	***1,488***	***418***	[redacted]
010 Office Supplies	52	50	64		51	1	(13)	
011 Travel Expense	171	167	349		178	11	(171)	
012 Materials	379	350	434		496	146	62	
013 Contracts	1,722	1,721	896		1,542	(179)	646	
014 Overtime Meals	5	5	10		7	2	(3)	
015 Frt, Post & Delivery	2,203	2,190	2,189		2,119	(71)	(70)	
016 Tools & Equipment	3	2	2		2	-	-	
017 Chemicals	6	-	-		-	-	-	
021 Telephones	478	477	485		282	(195)	(203)	
025 Leasing	24	24	24		29	5	5	
028 Consulting	440	440	4,281		415	(25)	(3,866)	
029 Membership Dues	72	72	107		99	27	(8)	
031 Fleet Fuel	584	584	431		459	(125)	28	
032 Subscrpt/Info.Software	-	-	-		-	-	-	
033 Rental/Mtnce equipment/software	1,210	1,210	760		818	(392)	58	
034 Appl. Software	2	2	(57)		6	4	63	
035 Comp.Hrdwr & Op.Sftwr	2	2	(42)		40	38	82	
040 Advertising	483	483	383		513	30	130	
041 Meals & Entertainment	102	101	150		108	7	(42)	
042 Employee Benefits	3,111	3,111	2,564		4,087	976	1,523	
051 Gen.Cost Recovery	-	-	-		-	-	-	
052 Non Reg.Cost Recovery	-	-	-		-	-	-	
055 Warranty & Service Contracts	10	10	1		10	-	9	
056 Training & Development	71	71	286		76	5	(210)	
058 Personal Equipment	72	71	52		48	(23)	(4)	
059 HR Costs	-	-	89		-	-	(89)	
060 Commissions	254	254	233		439	185	206	
061 Write-offs	4,319	4,319	5,235		5,722	1,403	487	
062 Recoveries	(1,390)	(1,390)	(1,558)		(2,336)	(946)	(778)	
064 Customer Recovery	21	21	63		23	2	(40)	
066 Other Goods & Services	-	-	48		-	-	(48)	
083 Short-term interest	(114)	(114)	(156)		(157)	(43)	(1)	
190 Misc revenue/recoveries	(314)	(100)	(82)		(134)	(34)	(52)	
Total Non-Labour	***13,978***	***14,133***	***17,241***		***14,942***	***809***	***(2,299)***	
Total	***30,660***	***30,162***	***34,340***		***32,459***	***2,297***	***(1,881)***	

Responsibility Area Customer Service	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	32,459	[redacted]	30,162	34,340
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Customer Service includes the customer care centre, billing and payment services, meter services, credit and collections, customer communications, heating solutions, large customer management, load and revenue forecasting and energy utilization programs.		[redacted]	2,297	(1,881)
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Labour** decrease due to the completion of customer service improvement initiative reduction in FTE's through retirements and attrition offset by wage increases		[redacted]		
> **Contracts** decrease due to the completion of customer service improvement initiatives				
> **Tools and Equipment** decrease due to reallocation to other division				
Telephone decrease due to cost efficiencies gained through centralized management of telephone expenses				
> **Consulting** decrease due to the completion of customer service improvement initiative				
> **Advertising** decrease due to the completion of customer service improvement initiative				
> **Employee Benefits** increase due to increased pension costs				
> **Commission** increase due to increased recoveries due to cost efficiencies gained in the management of Net Bad Debt				
> **Training and Development** due to the completion of customer service improvement initiative				
> **Short-term interest** decrease due to an increase in Demand Side Management financing contracts on behalf of Efficiency Nova Scotia, Inc.				
> **Misc Revenue\Recoveries** increase due to the establishment of wiring inspection seminars				
> **Recoveries** increased due to cost efficiencies gained in the management of Net Bad Debt				
> **Write-offs** increase due to expected increase in the average write-off amount				
> **Other variances**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases			1,488	
> **Materials** increase due to growth and forecasted decrease in partner funding in the customer energy utilization program for Holiday Lighting Exchanges			146	
> **Contracts** decrease due to NSPI no longer sourcing temporary contact centre labour services through external services			(179)	
> **Freight, Post & Delivery** decrease due to higher penetration of ebilling and reduced postage cost			(71)	
> **Telephone** decrease due to cost efficiencies gained through centralized management of telephone expenses			(195)	
> **Fleet Fuel** decrease due to lower fuel costs than projected and as a result of fleet fuel becoming more efficient (new vehicles, less idling)			(125)	
> **Rental/Maintenance Equipment/Software** decrease due to re-negotiation of third party agreement and completion of website redesign			(392)	
> **Employee Benefits** increase due to increased pension costs			976	
> **Commission** increase due to increased recoveries due to cost efficiencies gained in the management of Net Bad Debt			185	
> **Write-offs** increase due to expected increase in the average write-off amount and increased allowance for doubtful accounts due to increases in bills between 2009 and 2012.			1,403	
> **Recoveries** increased due to process improvement in the management of Net Bad Debt			(946)	
> **Other Variances**			7	

Responsibility Area Customer Service	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	32,459	[redacted]	30,162	34,340
Overview		**2012 Forecast vs. 2011 Forecast**	**2012 Forecast vs. 2009 Compliance Restated**	**2012 Forecast vs. 2010 Actual**
Customer Service includes the customer care centre, billing and payment services, meter services, credit and collections, customer communications, heating solutions, large customer management, load and revenue forecasting and energy utilization programs.		[redacted]	2,297	(1,881)
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases and Energy Efficiency overhead credit for 2010 offset by completion of customer service initiatives in 2010 and reductions in labour due to retirements and attrition				418
> **Travel expense** decrease due to one time travel costs associated with customer service initiatives				(171)
> **Materials** increase due to wiring inspector codebooks				62
> **Contracts** increase due to several one-time savings opportunities realized in 2010				646
> **Freight, Post & Delivery** decrease due to higher penetration of ebilling and reduced postage cost				(70)
> **Telephone** decrease due to cost efficiencies gained through centralized management of cell phone expenses				(203)
> **Consulting** decrease due to significant Customer Service improvement initiatives completed in 2010				(3,866)
> **Application Software** increase due to a one time software credit in 2010				63
> **Rental/Maintenance equipment/Software** increase due to new Automated Meter Infrastructure software license and one time 2010 credit				58
> **Computer Hardware & Operating Software** increase due to one time 2010 credit				82
> **Advertising** increase due to one time credit in 2010				130
> **Employee Benefits** increase due to increased pension costs				1,523
> **Training and Development** due to the completion of customer service improvement initiatives				(210)
> **Severance Costs** decrease due to one time 2010 expenses amount				(89)
> **Commission** increase due to increased recoveries due to cost efficiencies gained in the management of Net Bad Debt				206
> **Write-offs** increase due to expected increase in the average write-off amount				487
> **Recoveries** increased due to process improvements gained in the management of Net Bad Debt				(778)
> **Other Goods and Services** decrease due to one time 2010 expense				(48)
> **Misc Revenue\Recoveries** decreased due to the establishment of wiring inspection seminars				(52)
> **Other Variances**				(69)

Corporate Adjustments

(in Thousands of $)

	2009 Compliance	2009 Compliance Restated	2010 Actual	2011 Forecast	2012 Forecast	2012 Fct. Vs. 2009 Compliance Restated	2012 Fct. Vs. 2010 Act.	2012 Fct. Vs. 2011 Fct.
Total Labour	***3,013***	***3,013***	***3,506***	[redacted]	***3,247***	***234***	***(259)***	[redacted]
				[redacted]		-	-	[redacted]
036 Directors' Fees & Exp	-	-	264	[redacted]	-	-	(264)	[redacted]
042 Employee Benefits	-	-	(691)	[redacted]	-	-	691	[redacted]
057 Corp. Support Transfe	(756)	(756)	(1,154)	[redacted]	(1,007)	(251)	147	[redacted]
061 Write-offs	-	-	955	[redacted]	613	613	(342)	[redacted]
066 Other Goods & Services	250	250	248	[redacted]	591	341	343	[redacted]
083 Short-term interest	(946)	(946)	(1,088)	[redacted]	(1,066)	(120)	22	[redacted]
091 Tax Assessment	-	-	(55)	[redacted]	-	-	55	[redacted]
092 Vehicle Allocated Costs	(4,113)	(4,113)	(2,777)	[redacted]	(4,442)	(329)	(1,665)	[redacted]
095 Admin. Overheads	(15,126)	(15,126)	(28,368)	[redacted]	(22,991)	(7,865)	5,377	[redacted]
Total Non-Labour	***(20,691)***	***(20,691)***	***(32,666)***	[redacted]	***(28,302)***	***(7,611)***	***4,364***	[redacted]
				[redacted]		**-**	**-**	[redacted]
				[redacted]		-	-	[redacted]
Total	***(17,678)***	***(17,678)***	***(29,160)***	[redacted]	***(25,055)***	***(7,377)***	***4,105***	[redacted]

Responsibility Area Corporate Groups Total Corporate Adjustments	2012 Forecast	2011 Forecast	2009 Compliance Restated	2010 Actual
	(25,055)	[redacted]	(17,678)	(29,160)
Overview		2012 Forecast vs. 2011 Forecast	2012 Forecast vs. 2009 Compliance	2012 Forecast vs. 2010 Actual
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.		[redacted]	(7,377)	4,105
2012 Forecast vs. 2011 Forecast (Thousands of $)				
> **Vehicle Allocated Costs** decreased recovery due to decreased labour charged to capital		[redacted]		
> **Administrative Overheads** increased recovery due to increased capital spend				
> **Other Variations**				
2012 Forecast vs. 2009 Compliance Restated (Thousands of $)				
> **Labour** increase due to wage increases			234	
> **Corporate Support Transfer** increased due to increased costs			(251)	
> **Other Goods and Services** increase due to increased participation in Employee Share Purchase Plan			341	
> **Short-term Interest** decrease due to reduced inventory carrying costs			(120)	
> **Vehicle Allocated Costs** increased recovery due to increased capital spend			(329)	
> **Administrative Overheads** increased recovery due to increased capital spend			(7,865)	
> **Write-offs** increase in inventory obsolescence reallocation from Procurement			613	
2012 Forecast vs. 2010 Actual (Thousands of $)				
> **Labour** increase due to wage increases				(259)
> **Directors' Fees** decrease a result of actual 2010 director fees.				(264)
> **Employee Benefits** increase due to a resulting difference between actual pension expense and amount transferred to business units				691
> **Corporate Support Transfer** increased due to increased costs				147
> **Write-offs** decrease in inventory obsolescence reallocation from Procurement				(342)
> **Tax Assessment** increase is result of actual 2010 tax consultant costs				55
> **Vehicle Allocated Costs** increased recovery due to increased capital spend				(1,665)
> **Administrative Overheads** decreased recovery due to reduced capital spend				5,377
> **Other Variations**				365

Canadian Electricity Association | Association canadienne de l'électricité

2009

GENERATION EQUIPMENT STATUS

ANNUAL REPORT

EQUIPMENT RELIABILITY INFORMATION SYSTEM

Acknowledgements

The Canadian Electricity Association gratefully acknowledges the support of the participant utilities whose data was used in the preparation of this report. We also wish to thank the Generation Consultative Committee on Outage Statistics (CCOS) and in particular, its chair, Joe Renna (Ontario Power Generation) and its past Chair, Dr. Roy Billinton (University of Saskatchewan), for their support and guidance.

Canadian Electricity Association
Contact: Daniel Gent
gent@electricity.ca
www.electricity.ca

TABLE OF CONTENTS

LIST OF TABLES

INTRODUCTION

The Canadian Electricity Association (CEA) was founded in 1891 and is the voice of the Canadian electricity industry, promoting electricity as the critical enabler of the economy and Canadians' expectations for an enhanced quality of life. A safe, secure, reliable, sustainable and competitively priced supply of electricity is essential to Canada's prosperity. This 2009 Generation Equipment Status Reports contains information that feeds directly into the "reliable" portion of CEA's Mission.

Scope:

This annual report on Generating Unit performance in Canada includes statistics for commercial generating units in Canada of the following specifications:

- Combustion Turbine units with a Maximum Continuous Rating (MCR) > 1 MW
- Fossil units with MCR > 60 MW
- Hydro units with MCR > 5 MW
- Nuclear units with MCR > 200 MW
- Fossil units including Coal, Oil and Natural Gas

Use of Information:

Information from this report can be used by utility companies to

- benchmark Generating Unit performance
- make decisions regarding new Generating Unit Construction
- make decisions regarding existing Unit upgrades
- focus resources for maintenance programs and system planning

The goal of using the information is to maximize Generating Unit performance within a company's financial and logistical constraints.

Contributors:

The publication of this report would not be possible without the data contribution of member utilities. These members include:

ATCO Power
BC Hydro
Churchill Falls (Labrador Corp)
EPCOR
FortisBC
Manitoba Hydro
New Brunswick Power
Newfoundland & Labrador Hydro
Nova Scotia Power
Ontario Power Generation
RioTinto Alcan
SaskPower
TransAlta Utilities Corporation

History:

In 1975, the CEA adopted a proposal to create a system for the centralized collection, processing and reporting of reliability and outage statistics for electrical generation, transmission and distribution equipment. To coordinate the development of this system, CEA constituted the Consultative Committee on Outage Statistics (CCOS). In 2007, after many distinguished years of service, Dr. Roy Billinton stepped down as the Chair of this committee. Through the work for Dr. Billinton and the CCOS committee, statistics have been generated for the electricity systems that have been adopted world-wide. The current chair of the Generation – CCOS program is Joe Renna of Ontario Power Generation. The mission and vision of CCOS are as follows:

Mission:

Provide a comprehensive database of component and system reliability and performance data which will assist member utilities in the optimal utilitization of corporate and financial resources.

Vision:

To be recognized as a world-class reliability database which meets the needs of its member utilities.

DATABASE OVERVIEW

CEA has been collecting performance data for Canadian generating units from participating utilities since 1978. This database of information is used to produce this annual report. There is a wealth of information stored in the database including:

- Performance data on over 1000 generating units
- Details of over 7000 equipment components
- Fuel types including hydro, fossil, combustion turbine, internal combustion and nuclear
- Details about individual generating units including manufacturers, Maximum Continuous Ratings (MCRs), ages
- Design information including speeds, ratings, temperatures, insulation types, pressures, capacities, diameters
- Component information for fans, pumps, condensers, boilers, generators, turbine reactors

Participating utilities monitor every change in state including:

- Normal operation
- derated states – including forced and scheduled
- outage states – including forced and scheduled
- available but not operating

More details about the states monitored can be found in section 4, Definition of Terms, Table of State and Time Codes.

The collection of this data follows a common set of definitions that has been accepted as the global industry standard for over 20 years. This data is reported to CEA annually and CEA follows a rigorous validation process for monitoring data quality to ensure that this report is of a high standard.

To date the database contains over 5,000,000 events.

The **Weighted Capability Factor**, by generating unit type, for 2009 and for the period of 2005-2009 Is as follow:

	Hydro	Fossil	Nuclear	Combustion
2009	91.51	71.21	62.59	88.27
2004-2009	91.37	79.32	72.96	88.62

INDIVIDUAL GENERATING UNIT PERFORMANCE

The tables in this section list the generating units of each type which experienced the lowest Incapability Factors (ICbF) and the highest Operating Factors in the 2009 calendar year.

Table 1 A – Hydro Units by ICbF with Operating Time more than 4000 hrs

Ranking	Plant Name	Unit #	Operated By	ICBF(%)
1	Pointe du Bois	5	Manitoba Hydro	0.00
2	Island Falls	7	SaskPower	0.02
3	McArthur Falls	7	Manitoba Hydro	0.03
4	Corralinn	3	Fortis BC (Aquila Networks)	0.03
5	Wellington	2	SaskPower	0.03
6	Long Spruce	5	Manitoba Hydro	0.04
7	Lower Bonnington	1	Fortis BC (Aquila Networks)	0.04
8	Wellington	1	SaskPower	0.04
9	Lower Bonnington	3	Fortis BC (Aquila Networks)	0.06
10	E. B. Campbell	6	SaskPower	0.07

Table 1 B – Hydro Units by Operating Factor with Operating Time more than 4000 hrs

Ranking	Plant Name	Unit #	Operated By	Op Fact (%)
1	Pine Falls	3	Manitoba Hydro	100.00
2	Charlot River	1	SaskPower	100.00
3	McArthur Falls	7	Manitoba Hydro	99.89
4	Pointe du Bois	5	Manitoba Hydro	99.89
5	Pine Falls	6	Manitoba Hydro	99.88
6	Kelsey	4	Manitoba Hydro	99.88
7	Charlot River	2	SaskPower	99.84
8	Seven Sisters	1	Manitoba Hydro	99.77
9	Coteau Creek	1	SaskPower	99.75
10	Pointe du Bois	6	Manitoba Hydro	99.75

Table 2 A – Fossil Units by ICbF with Operating Time more than 4000 hrs

Ranking	Plant Name	Unit #	Operated By	ICBF(%)
1	Coleson Cove	1	New Brunswick Power	0.63
2	Brandon	5	Manitoba Hydro	1.73
3	Genesee	2	EPCOR	2.67
4	Sheerness	1	ATCO Power	2.74
5	Lingan	1	Nova Scotia Power Inc.	3.67
6	Burrard	3	BC Hydro Corporation	3.95
7	Burrard	2	BC Hydro Corporation	3.99
8	Battle River	5	ATCO Power	4.19
9	Belledune	2	New Brunswick Power	4.29
10	Boundary Dam	6	SaskPower	8.21

Table 2 B – Fossil Units by Operating Factor with Operating Time more than 4000 hrs

Ranking	Plant Name	Unit #	Operated By	Op Fact (%)
1	Sheerness	1	ATCO Power	97.76
2	Boundary Dam	6	SaskPower	95.90
3	Belledune	2	New Brunswick Power	95.73
4	Genesee	2	EPCOR	94.91
5	Lingan	1	Nova Scotia Power Inc.	94.21
6	Battle River	5	ATCO Power	91.34
7	Genesee	1	EPCOR	90.76
8	Point Tupper	2	Nova Scotia Power Inc.	90.37
9	Boundary Dam	4	SaskPower	90.07
10	Sheerness	2	ATCO Power	89.75

Table 3A – Combustion Turbine Units by ICbF with Operating Time more than 100 hrs

Ranking	Plant Name	Unit #	Operated By	ICBF (%)
1	Tusket	1	Nova Scotia Power Inc.	0.00
2	Victoria Junction	1	Nova Scotia Power Inc.	0.10
3	Ermine	1	SaskPower	0.49
4	Grand Manan	3	New Brunswick Power	0.61
5	Victoria Junction	2	Nova Scotia Power Inc.	0.68

Table 3B – Combustion Turbine Units by Operating Factor with Operating Time more than 100 hrs

Ranking	Plant Name	Unit #	Operated By	Op Fact (%)
1	Fort Nelson Gas	1	BC Hydro Corporation	89.95
2	Tufts Cove	5	Nova Scotia Power Inc.	64.57
3	Tufts Cove	4	Nova Scotia Power Inc.	47.14
4	Landis	1	SaskPower	11.17
5	Meadow Lake	1	SaskPower	10.01

Table 4A – Nuclear Units by ICbF with Operating Time more than 100 hrs

Ranking	Plant Name	Unit #	Operated By	ICBF (%)
1	Pickering NGS-B	7	Ontario Power Generation	5.40
2	Pickering NGS-B	8	Ontario Power Generation	7.44
3	Pickering NGS-A	1	Ontario Power Generation	7.52
4	Darlington	1	Ontario Power Generation	9.01
5	Darlington	4	Ontario Power Generation	10.26

Table 4B – Nuclear Units by Operating Factor with Operating Time more than 100 hrs

Ranking	Plant Name	Unit #	Operated By	Op Fact (%)
1	Pickering NGS-B	7	Ontario Power Generation	92.37
2	Pickering NGS-B	8	Ontario Power Generation	85.33
3	Pickering NGS-A	1	Ontario Power Generation	77.84
4	Pickering NGS-B	6	Ontario Power Generation	74.56
5	Darlington	2	Ontario Power Generation	68.92

Definition of terms

Generating Unit: all equipment up to the high voltage terminals of the generator transformer and the station service transformers.

Maximum Continuous Rating (MCR): the gross maximum electrical output (in megawatts) which a generating unit has been designed for and/or shown by acceptance test to be capable of producing continuously.

The definitions of outages, deratings, states and times are reproduced here from the Instruction Manual on Generation Equipment Status.

4.1 Definition of Outages and Deratings

Forced Outage: the occurrence of a component failure or other condition which requires that the generating unit be removed from service immediately or up to and including the very next weekend.

There are 4 types of Forced Outages:
1. **Sudden Forced Outage**: the occurrence of a component failure or other condition which results in the unit being automatically or manually tripped.
2. **Immediately Deferrable Forced Outage:** the occurrence of a component failure or other condition which requires that the unit be removed from service within 10 minutes.
3. **Deferrable Forced Outage**: the occurrence of a component failure or other condition which requires that the unit be removed from service from 10 minutes up to and including the very next weekend.
4. **Starting-Failure Outage**: the unsuccessful attempt to bring a unit from a shutdown to synchronized or from synch-condensed or spin no load to generate with the electric system within a specified time interval. (The specified time interval may be different for individual units and should allow a reasonable time for the unit to pick up load.) This definition is most commonly associated with stand-by and peak units. *Note: repeated failures to start for the same cause without accomplishing corrective repairs are counted as one failure and the repeated attempts at starting are counted as a single attempt.*

Maintenance Outage: the removal of a generating unit from service to perform work on specific components which could have been postponed past the very next weekend. This is work done to prevent a potential forced outage and which could not be postponed from season to season.

Planned Outage: the removal of a generating unit from service for inspection and/or general overhaul of one or more major equipment groups. This work is usually scheduled well in advance (e.g. annual boiler overhaul, five-year turbine overhaul).

Forced Derating: a reduction (below MCR) of generating unit capacity in excess of 2% of its MCR resulting from a component failure or other condition which requires that the generating unit be derated at once or as soon as possible up to and including the very next weekend.

Scheduled Derating: a reduction (below MCR) of generating unit capacity in excess of 2% of its MCR resulting from a planned or maintenance outage of a piece of equipment.

4.2 Definition of States, (State Codes)

Operating State, (11): the generating unit is spinning and/or synchronized with the system and is capable of operating at MCR under normal operating procedures.

Operating under a Forced Derating, (12): the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a forced derating being in effect.

Operating under a Scheduled Derating, (13): the generating unit is synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

Available But Not Operating State, (14): the generating unit can carry its MCR but is not being operated to supply system load.

Available But Not Operating – Forced Derating State, (15): the generating unit can deliver only part of its MCR due to a forced derating but is not being operated to supply system load.

Available But Not Operating – Scheduled Derating State, (16): the generating unit can deliver only part of its MCR due to a scheduled derating but it is not being operated to supply system load.

Forced Outage State, (21): the generating unit has a forced outage which requires that it be removed from service.

Forced Extension of a Maintenance Outage State, (22): the generating unit has an outage resulting from a condition discovered during a maintenance outage which has forced the extension of the maintenance outage.

Forced Extension of a Planned Outage State, (23): the generating unit has an outage resulting from a condition discovered during a planned outage which has forced the extension of the planned outage.

Maintenance Outage State, (24): the generating unit has a maintenance outage which requires that it be removed from service.

Planned Outage State, (25): the generating unit has a planned outage which requires that it be removed from service.

Not in Commercial Service State, (30): the generating unit is decommissioned, mothballed, or on a prolonged outage to make modifications that will alter its performance beyond the original design and/or provide life extension through rehabilitation. The type codes associated with this state are:

1 - Decommissioned
2 - Mothballed
3 - Refurbishment
4 - Deferred

Operating as a Synchronous Condenser/Spin No-Load: The above state codes can also be used to identify the various modes of synchronous condenser or spin no-load (spinning reserve at 0 MW) operation as follows:

STATE OF THE TURBINE	STATE CODE OF THE UNIT
Spin No-Load De-Coupled (Hydro units only)	11, 12, 13
Synchronous Condenser Coupled	11, 12, 13
Unbolted or declutched but available	14, 15, 16
Unbolted or declutched but not available	21,22,23,24, 25

4.3 Definition of Times

O: the number of hours the generating unit was in the Operating State during the period.

O(FD): the number of hours the generating unit was operating under a Forced Derating during the period.

O (SD): the number of hours the generating unit was operating under a Scheduled Derating during the period.

ABNO: the number of hours the generating unit was in the Available But Not Operating State.

ABNO(FD): the number of hours the generating unit was in the Available But Not Operating - Forced Derating State.

ABNO (SD): the number of hours the generating unit was in the Available But Not Operating - Scheduled Derating State.

FO: the number of hours the generating unit was in a Forced Outage State.

FEMO: the number of hours the generating unit was in a Forced Extension of a Maintenance Outage State.

FEPO: the number of hours the generating unit was in a Forced Extension of a Planned Outage State.

MO: the number of hours the generating unit was in the Maintenance Outage State.

PO: the number of hours the generating unit was in the Planned Outage State.

Table of State and Time Codes
(Summary of Section 4.2 and 4.3)

States	State Codes	Duration (Hours)
Available States		
Operating	11	O
Operating under a Forced Derating	12	O(FD)
Operating under a Scheduled Derating	13	O(SD)
Available But Not Operating	14	ABNO
Available But Not Operating - Forced Derating	15	ABNO(FD)
Available But Not Operating - Scheduled Derating	16	ABNO(SD)
Not-Available States:		
Forced Outage	21	FO
Forced Extension of Maintenance Outage	22	FEMO
Forced Extension of Planned Outage	23	FEPO
Maintenance Outage	24	MO
Planned Outage	25	PO
No-in-Commercial Service	30	NICS

The Concept of Adjusted Time:

To take into account the derated levels of a generating unit, the operating time at these levels is transformed into an equivalent outage time. Thus, the time of X% of MCR, called O(FD) x, is converted to an equivalent outage time, called O(FD)adj according to the transformation.

$$O(FD)adj = \left[\frac{100 - X}{100}\right] O(FD)x$$

For example, if a generating unit is derated to 80 percent of its MCR for 5 hours, that would be equivalent to a full outage of the generating unit for 1 hour. O(SD), ABNO(FD) and ABNO(SD) are treated in the same manner.

4.4 Definition of Headings Used on the Tables of Sections 5 and 6

4.4.1 Column Headings

UNIT YEARS (A): the number of Unit Hours divided by 8760. The number of Unit Hours is the sum of the durations of all states (i.e. O + O(FD) + O(SD) + ABNO + ABNO(FD) + ABNO(SD) + FO + FEMO + FEPO + MO + PO) of the generating units being considered.

ABNOF (%): the Available But Not Operating Factor. It is calculated by dividing ABNO + ABNO(FD) + ABNO(SD) by Unit Hours times 100.

OP FACTOR (%): Operating Factor. It is calculated by dividing the Total Operating Time by Unit Hours times 100. Total Operating Time means the sum of O + O(FD) + O(SD).

NO. OF FORCED OUTAGES: the number of occurrences of State Codes 21, 22 and 23.

TOTAL F.O.T. (A): Total Forced Outage Time expressed in years. It is FO + FEMO + FEPO divided by 8760.

MAXIMUM F.O.D. (H): the longest single residence in hours of one of the forced outage states 21, 22 and 23 in the study period.

TOTAL EQ. OUT. TIME (A): the Total Equivalent Outage Time expressed in years. It is the Total Forced Outage Time plus planned and maintenance outage times plus adjusted derated times (i.e. FO + FEMO + FEPO + MO + PO + O(FD) adj + O(SD) adj + ABNO(FD) adj + ABNO(SD) adj all divided by 8760). This equivalent time is used when calculating ICbF.

ICbF (%): the Incapability Factor. It is the ratio of Total Equivalent Outage Time, in hours, to number of Unit Hours times 100.

CbF (%) is the complement of the Incapability Factor. It is calculated by subtracting ICbF from 100. This index is not listed in the report tables.

WEIGHTED CAPABILITY FACTOR (%) is the Capability Factor of a unit weighted by its MCR

Weighted Capability Factor = 1- weighted ICbF

$$= 1 - \frac{\Sigma ICbF*MCR}{\Sigma MCR}$$

FAIL RATE: the Failure Rate. It is the rate at which a generating unit encounters a forced outage. It is computed by dividing the Number of Transitions from an Operating State (11, 12 and 13) to a Forced Outage (21) by the Total Operating Time times 8760.

MEAN F.O.D. (H): the mean duration of a forced outage. It is computed by dividing the Total Forced Outage Time by the Number of Forced Outages.

FOR (%): the Forced Outage Rate. It is the ratio of Total Forced Outage Time to Total Forced Outage Time plus Total Operating Time times 100.

$$FOR = \frac{FO + FEMO + FEPO}{FO+FEMO+FEPO+O+O(FD)+O(SD)} X100$$

Cautionary Note: The Forced Outage Rate obtained by the above equation is not equal to Lambda over Lambda + Mu (l/l+m) where Lambda (l) is the Fail Rate and Mu (m) is the reciprocal of Mean F.O.D.

DAFOR (%): the Derated Adjusted Forced Outage Rate. It is the ratio of Equivalent Forced Outage Time (i.e. FO + FEMO + FEPO + O(FD) adj + ABNO(FD) adj) to Equivalent Forced Outage Time plus Total Equivalent Operating Time (i.e. O + O(SD) + (O(FD) - 0(FD)adj)). This can be written as follows:

$$DAFOR = \frac{FO+FEMO+FEPO+O(FD)adj+ABNO(FD)adj}{FO+FEMO+FEPO+ABNO(FD)adj+O+O(FD)+O(SD)} X100$$

MOF (%): the Maintenance Outage Factor. It is computed by dividing the number of maintenance outage hours by the number of Unit Hours times 100.

POF (%): the Planned Outage Factor. It is computed by dividing the number of planned outage hours by the number of Unit Hours times 100.

SYN. CD. FACTOR (%): the Synchronous Condenser Factor. It is the total hours spent as a synchronous condenser divided by the number of Unit Hours times 100.

SR: the Starting Reliability. It gives the ratio of successful starts to start attempts.

$$\textbf{SR} = \frac{\text{Total Attempted Start} - \text{Total Start Failures}}{\text{Total Attempted Starts}}$$

Total Start Failures= Total number of occurences of State 21 type 4

Total Attempted Starts = Total Start Failures plus the number of transitions to states 11, 12 and 13 from any of the remaining states plus the number of transitions into a synchronous condenser mode from a not operating state.

UFOP (%): the Utilization Forced Outage Probability. It is the probability that a generating unit will not be available when required.

$$\text{UFOP} = \frac{f(FO + FEMO + FEPO)}{f(FO + FEMO + FEPO) + O + O(SD) + O(FD)}$$

Where f = Demand Factor

$$= \left[\frac{1}{R} + \frac{1}{T}\right] \Big/ \left[\frac{1}{D} + \frac{1}{r} + \frac{1}{T}\right]$$

Where r = Average Forced Outage Time (see above)
D = average in-service time per occasion of demand

$$= \frac{O + O(FD) + O(SD)}{SR \times \text{Total Attempted Starts}}$$

T = average reserve shutdown time between periods of need, exclusive of periods for maintenance or other planned unavailability.

$$D + T = \frac{O+O(FD)+O(SD)+ABNO+ABNO(FD) + ABNO(SD)}{\text{Total Attempted Starts}}$$

DAUFOP (%): the Derated Adjusted Utilization Forced Outage Probability. It is the probability that a generating Unit will not be available when required (derating included). It can be calculated as follows:

$$\text{DAUFOP} = \frac{f\,(FO + FEMO + FEPO) + O(FD)adj}{f\,(FO + FEMO + FEPO) + O + O(FD)\,O(SD)}$$

4.4.2 Row Headings

The row headings indicate the data for which the statistics in that row have been calculated.

YEARS 0 UNIT: all year zero data for a particular generating unit type over the specified time interval. For example, in the combined 1998-02 report, this row would have the 2002 data for the generating units commissioned in 2002 and the 2001 data for the generating units commissioned in 2001 and so on.

EXCL YR 0: all data for a particular generating unit type minus the year 0 data.

ALL UNITS: the data for all generating units of a particular type.

CLASSIFICATION BY MCR (MW): the data for all generating units whose MCR's fall within the indicated range.

CLASSIFICATION BY YEAR OF SERVICE: the data for all generating units in the indicated year or years of service. For example, a generating unit that was commissioned in 1994 would have its 1994 data grouped in the "0" row and its 1995 data in the "1st" row.

CLASSIFICATION BY OPERATING FACTOR: the data for all generating units with operating factors in the indicated ranges over the specified time interval.

4.5 Calculation of Cumulative Normalized Unit Years

Cumulative Normalized Unit Years is plotted on one of the graphs in Section 5-1 of this report. The information to produce the figure was taken from the Classification By Operating Factor sections of Tables 6.1.1, 6.2.1, 6.3.1 and 6.4.1. The calculation of the Cumulative Normalized Unit Years corresponding to the Operating Factor of 50% for combustion turbine units is given below to illustrate the method of calculation. Referring to Table 6.3.1, the sum of the unit years with operating factor equal to or less than 50% is 34 unit years. As the total for all units is 36.0 unit years, the percentage of unit years with operating factor equal to or less than 50% is (34/36) x 100 or 94.4% as is plotted on the graph.

5.0
All Unit Types Summary Statistics

ALL CANADA Summary

Table 5.1

External Causes Excluded, 2009 Data

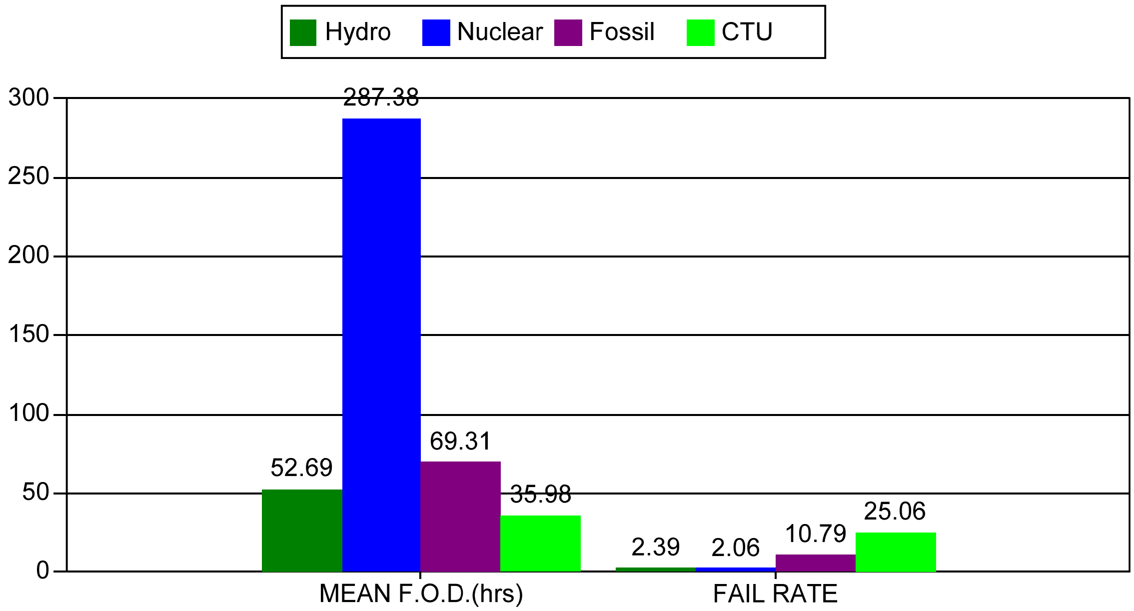
	Unit years (A)	ABNOF (%)	OP Time (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	Attempted Starts	Successful Starts	MOF (%)	POF (%)
Combustion Turbine Unit																	
Year 0 Units	0.2	92.97	0.0	6.42	5	0.0	4.70	1.81	8.64	8.64	0.0	0.61	0	34	29	0.00	0.00
Exc. Year 0	29.1	82.33	2.5	8.59	130	0.6	1108.95	37.29	18.07	37.02	3.4	11.77	23.97	1288	1273	5.24	1.69
All Units	**29.2**	**82.39**	**2.5**	**8.58**	**135**	**0.6**	**1108.95**	**35.98**	**18.03**	**36.93**	**3.4**	**11.70**	**23.86**	**1322**	**1302**	**5.21**	**1.68**
Fossil Generating Unit																	
Year 0 Units	0.0	0.00	0.0	0.00	0	0.0	0.00	0.00	0.00	0.00	0.0	0.00	0	0	0	0.00	0.00
Exc. Year 0	72.3	22.09	39.3	50.32	538	4.3	2850.15	69.31	8.84	17.11	20.8	26.67	9.36	1650	1643	3.17	11.63
All Units	**72.3**	**22.09**	**39.3**	**50.32**	**538**	**4.3**	**2850.15**	**69.31**	**8.84**	**17.11**	**20.8**	**26.67**	**9.36**	**1650**	**1643**	**3.17**	**11.63**
Hydro Generating Unit																	
Year 0 Units	0.9	34.66	0.2	28.74	2	0.0	136.18	98.42	8.23	8.23	0.3	36.41	8.04	61	61	6.96	26.86
Exc. Year 0	448.8	11.88	356.6	77.14	1072	6.4	7246.67	52.60	1.77	1.88	37.9	8.19	1.99	40878	40813	1.06	5.63
All Units	**449.7**	**11.92**	**356.8**	**77.05**	**1074**	**6.5**	**7246.67**	**52.69**	**1.77**	**1.88**	**38.2**	**8.24**	**2.00**	**40939**	**40874**	**1.07**	**5.67**
Nuclear Generating Unit																	
Year 0 Units	0.0	0.00	0.0	0.00	0	0.0	0.00	0.00	0.00	0.00	0.0	0.00	0	0	0	0.00	0.00
Exc. Year 0	10.4	0.00	6.8	56.70	19	0.6	779.87	287.38	6.94	9.65	3.9	32.55	1.67	20	20	0.00	25.11
All Units	**10.4**	**0.00**	**6.8**	**56.70**	**19**	**0.6**	**779.87**	**287.38**	**6.94**	**9.65**	**3.9**	**32.55**	**1.67**	**20**	**20**	**0.00**	**25.11**

TOTAL NUMBER OF COMBUSTION GENERATING UNITS:	31.00
TOTAL NUMBER OF FOSSIL GENERATING UNITS:	77.00
TOTAL NUMBER OF HYDRO UNITS:	462.00
TOTAL NUMBER OF NUCLEAR GENERATING UNITS:	13.00

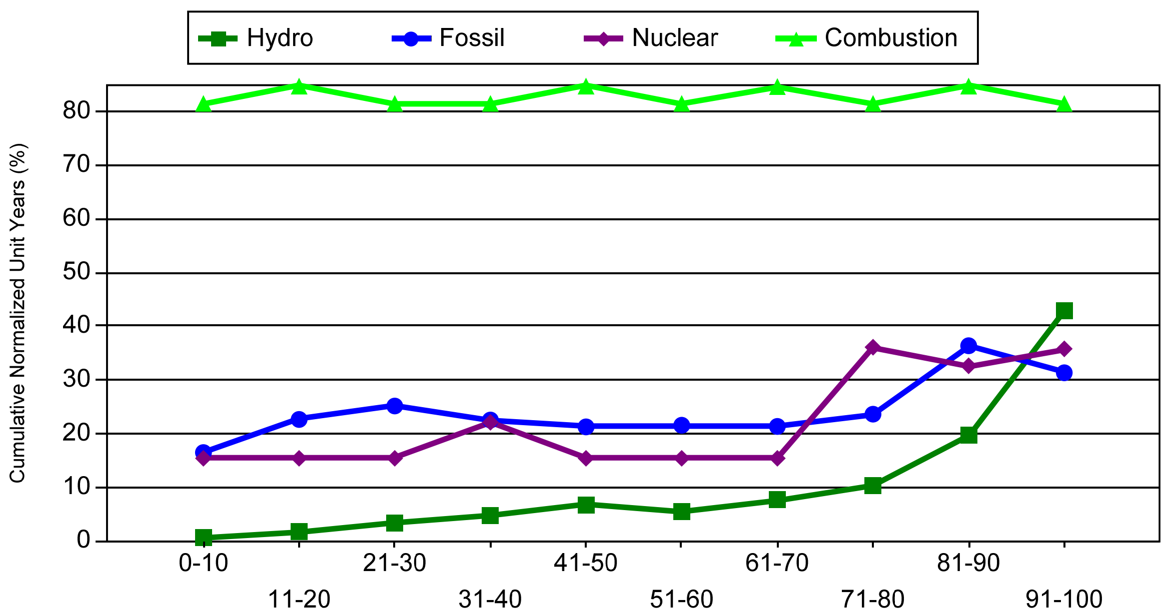
ALL CANADA Summary

External Causes Excluded, 2009 Data

Table 5.1



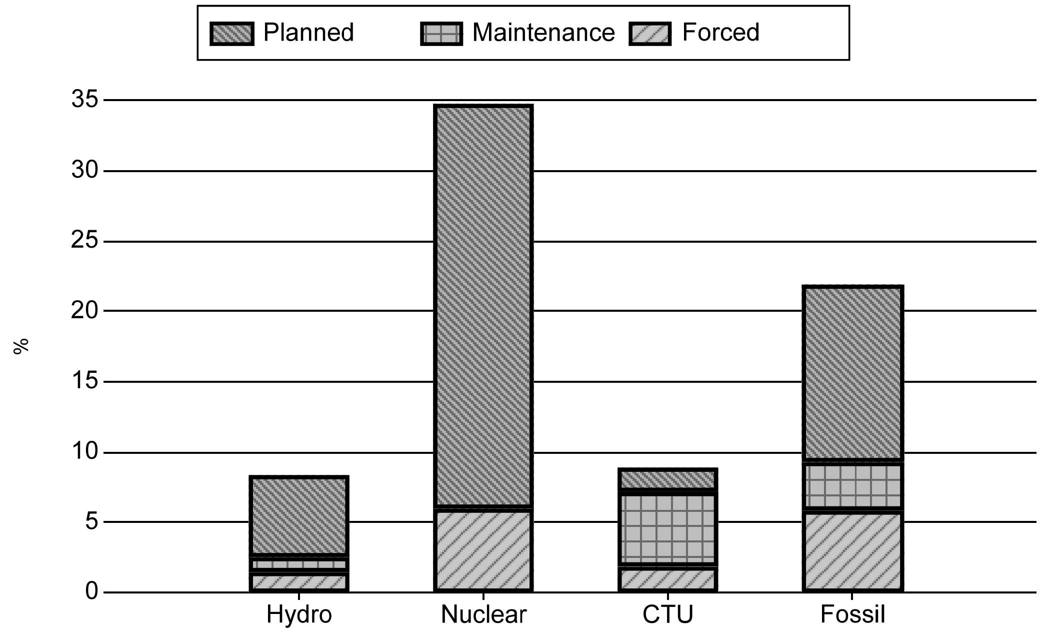
Comparison of Failure Rate & Mean Forced Outage Duration for different generating unit types based on 2009 data.



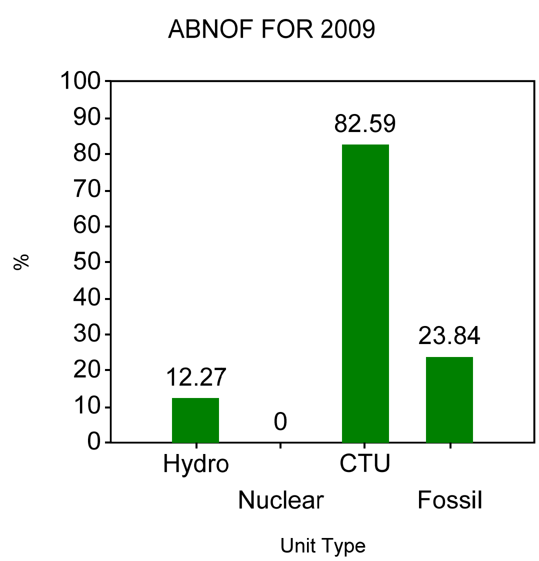
Cumulative Normalized Unit Years vs. Operating Factor for different generating unit types based on 2009 data.

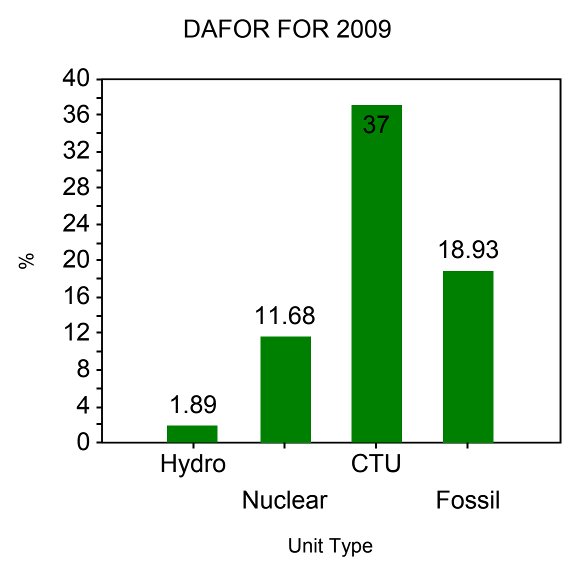
ALL CANADA Summary — Table 5.1

External Causes Excluded, 2009 Data



Comparison of ICbF for different generating unit types based on 2009 data.





ALL CANADA Summary — Table 5.2

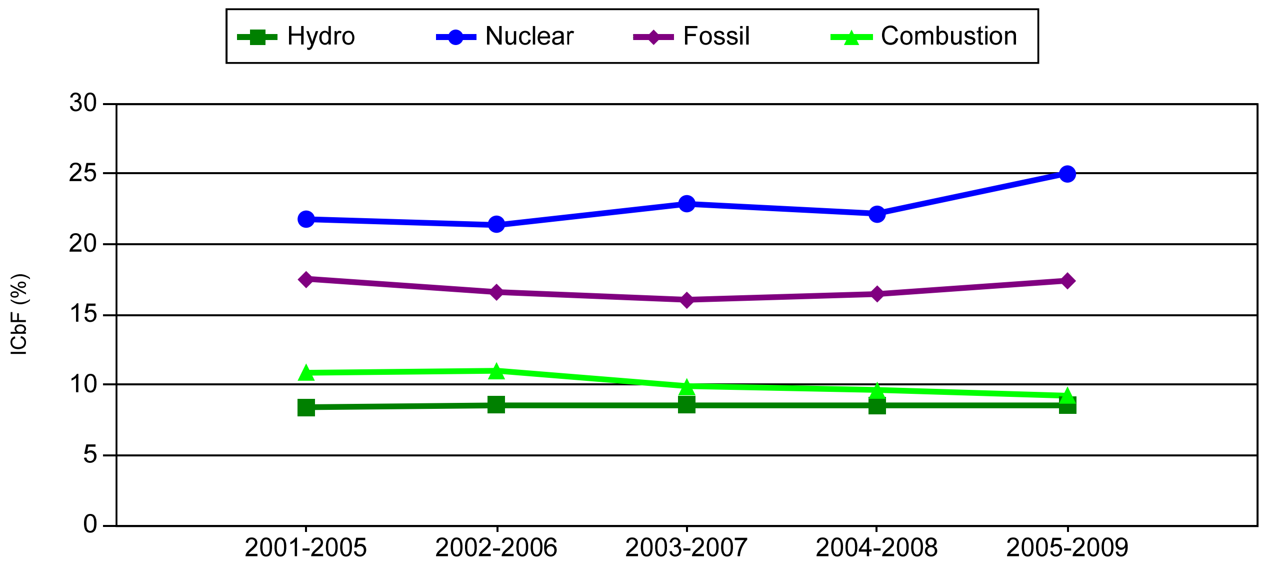
External Causes Excluded, 2005 to 2009 Data

	Unit years (A)	ABNOF (%)	OP Time (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	Attempted Starts	Successful Starts	MOF (%)	POF (%)
Combustion Turbine Unit																	
Year 0 Units	2.2	34.64	1.3	60.14	43	0.0	107.95	7.18	2.64	3.48	0.1	5.64	17.70	541	535	0.56	2.91
Exc. Year 0	164.5	80.99	15.4	9.34	639	5.7	8016.01	77.51	26.78	36.07	19.1	11.56	16.85	7259	7154	2.18	3.71
All Units	**166.6**	**80.39**	**16.7**	**10.00**	**682**	**5.7**	**8016.01**	**73.07**	**25.34**	**34.35**	**19.2**	**11.49**	**16.92**	**7800**	**7689**	**2.15**	**3.70**
Fossil Generating Unit																	
Year 0 Units	0.0	0.00	0.0	0.00	0	0.0	0.00	0.00	0.00	0.00	0.0	0.00	0	0	0	0.00	0.00
Exc. Year 0	384.7	21.15	232.8	58.06	2994	18.9	3688.95	55.28	7.10	11.15	80.1	19.98	9.77	8436	8402	2.58	9.41
All Units	**384.7**	**21.15**	**232.8**	**58.06**	**2994**	**18.9**	**3688.95**	**55.28**	**7.10**	**11.15**	**80.1**	**19.98**	**9.77**	**8435**	**8401**	**2.58**	**9.41**
Hydro Generating Unit																	
Year 0 Units	4.7	10.19	3.3	71.11	19	0.1	162.30	25.85	1.65	1.65	0.9	18.41	3.60	294	287	1.35	15.86
Exc. Year 0	2816.5	12.82	2202.3	75.54	8082	51.3	8783.98	55.65	2.27	2.41	244.3	8.38	2.30	219444	217894	0.73	5.76
All Units	**2821.2**	**12.81**	**2205.7**	**75.53**	**8101**	**51.4**	**8783.98**	**55.58**	**2.27**	**2.41**	**245.2**	**8.40**	**2.31**	**219740**	**218183**	**0.73**	**5.78**
Nuclear Generating Unit																	
Year 0 Units	0.0	0.00	0.0	0.00	0	0.0	0.00	0.00	0.00	0.00	0.0	0.00	0	0	0	0.00	0.00
Exc. Year 0	49.3	0.01	37.0	64.66	125	5.1	5700.87	360.22	10.29	12.11	13.7	23.90	2.14	125	124	0.00	12.58
All Units	**49.3**	**0.01**	**37.0**	**64.66**	**125**	**5.1**	**5700.87**	**360.22**	**10.29**	**12.11**	**13.7**	**23.90**	**2.14**	**125**	**124**	**0.00**	**12.58**

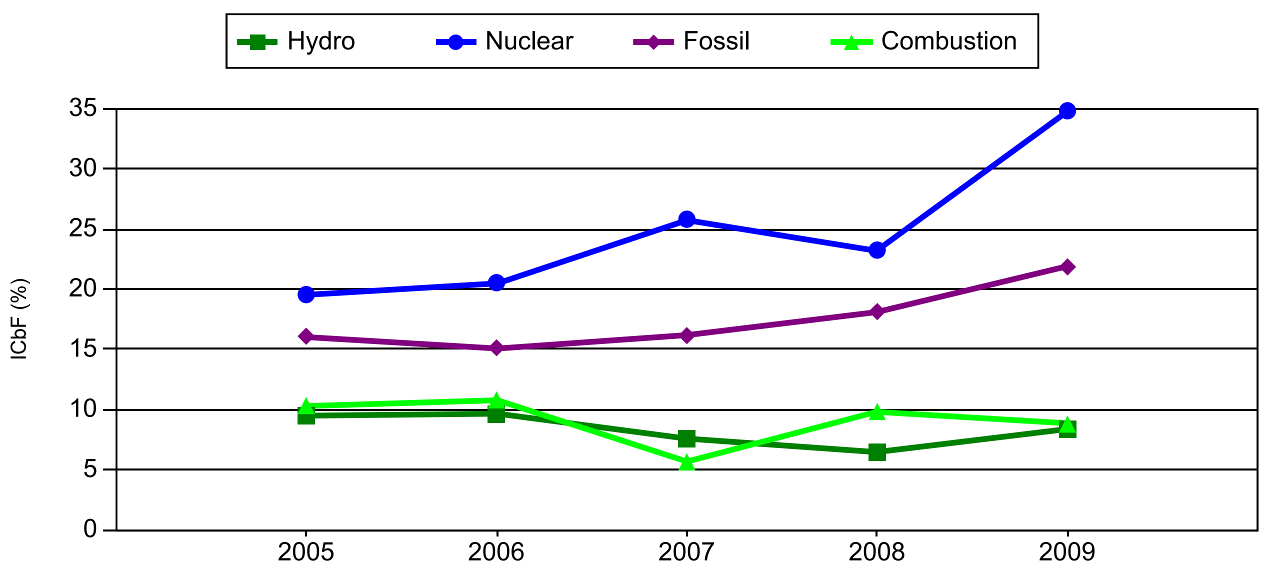
TOTAL NUMBER OF COMBUSTION GENERATING UNITS	47.00
TOTAL NUMBER OF FOSSIL GENERATING UNITS:	94.00
TOTAL NUMBER OF HYDRO UNITS:	796.00
TOTAL NUMBER OF NUCLEAR GENERATING UNITS:	14.00

ALL CANADA Summary — Table 5.2

External Causes Excluded, 2005 - 2009 Data



ICbF by generating unit type - 5 year rolling average trends

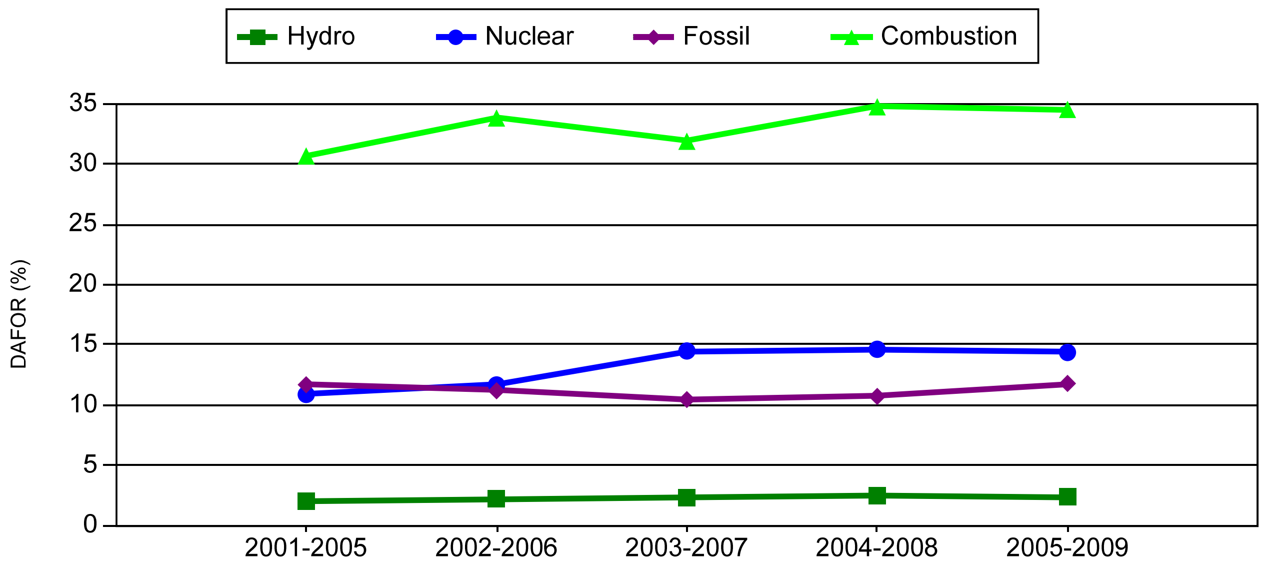


ICbF by generating unit type - 5 year rolling average trends

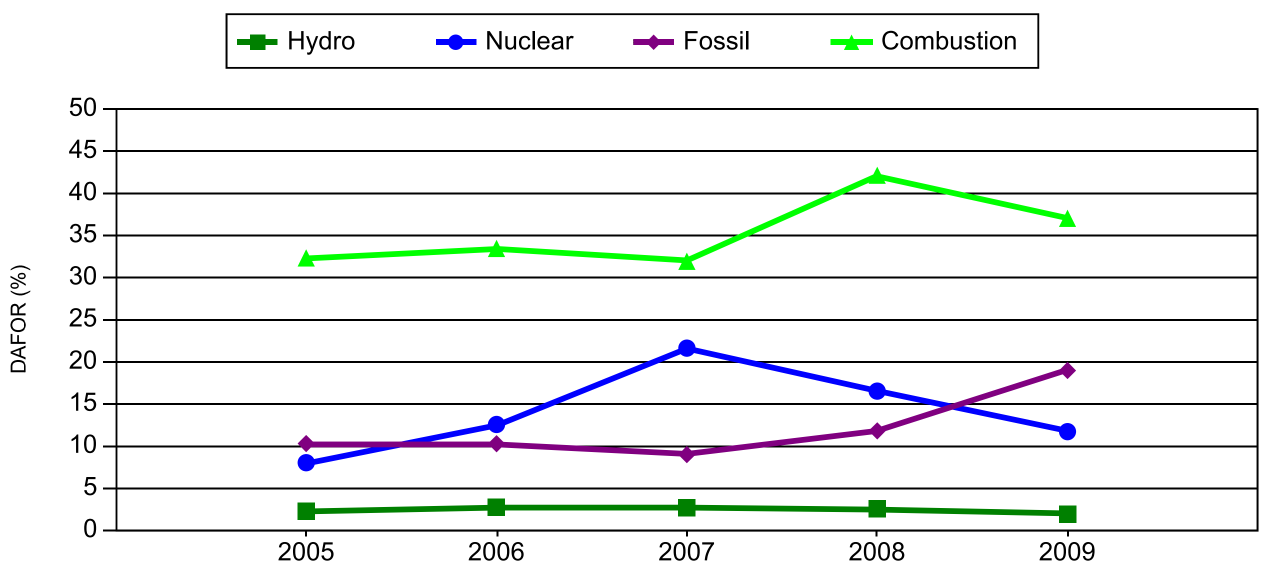
ALL CANADA Summary

Table 5.2

External Causes Excluded, 2005 - 2009 Data



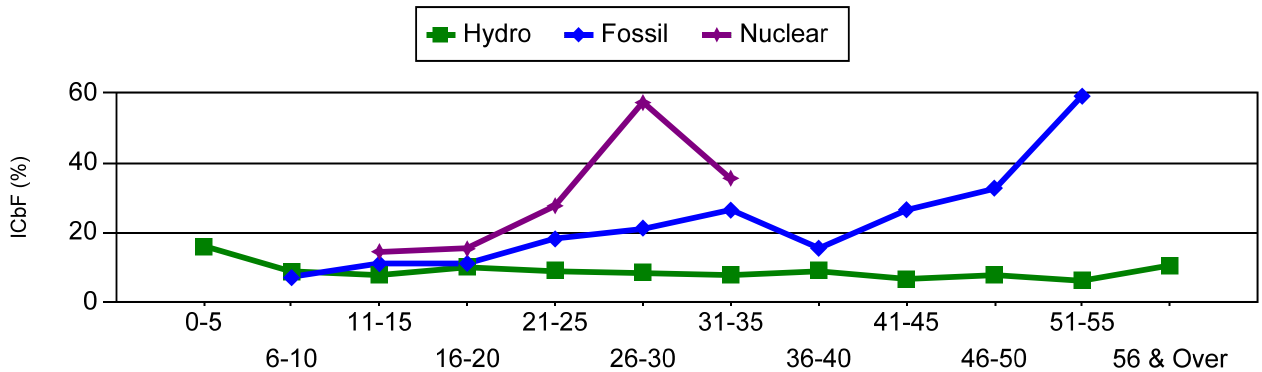
DAFOR by generating unit type - 5 year rolling average trends



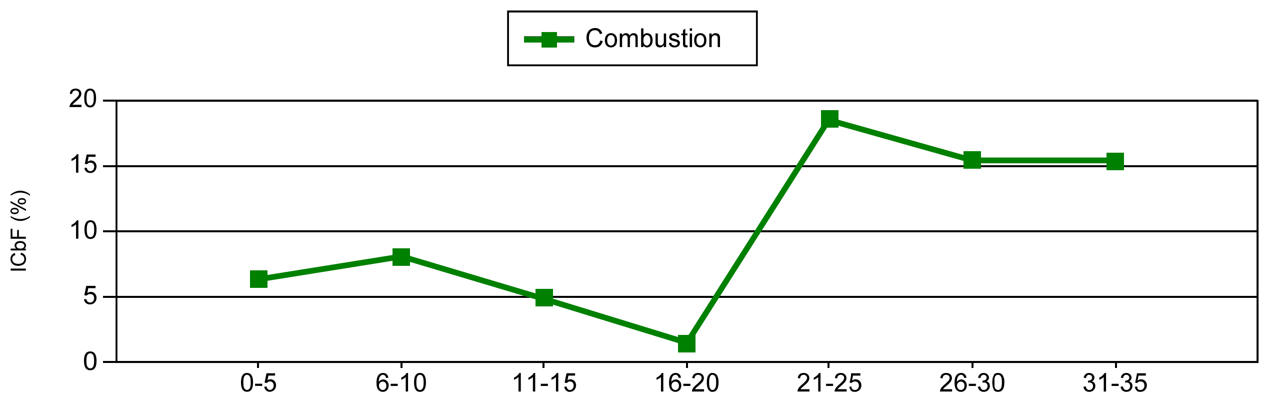
DAFOR by generating unit type

ALL CANADA Summary
External Causes Excluded, 2005 - 2009 Data

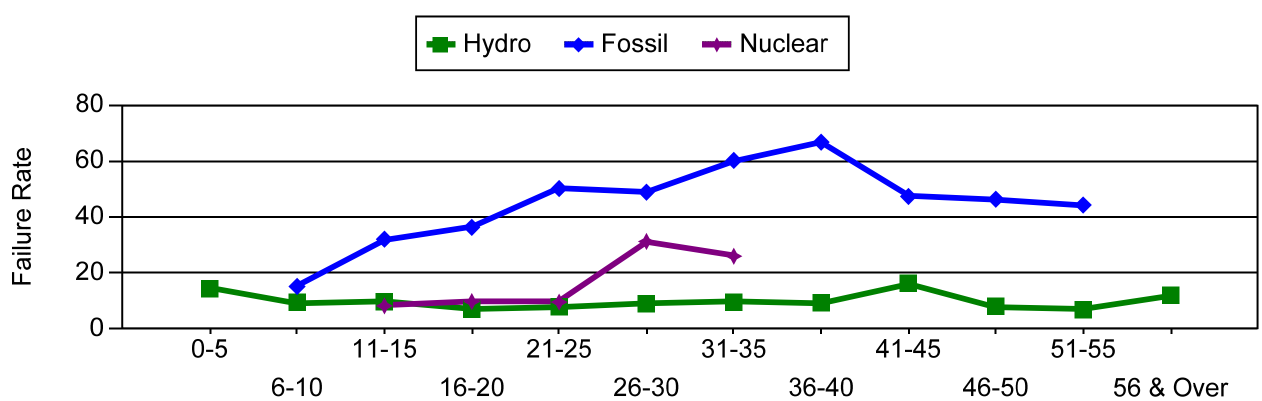
Table 5.2



The effect of age on ICbF for different generating unit types based on 2005-2009 data.



The effect of age on ICbF for different generating unit types based on 2005-2009 data.

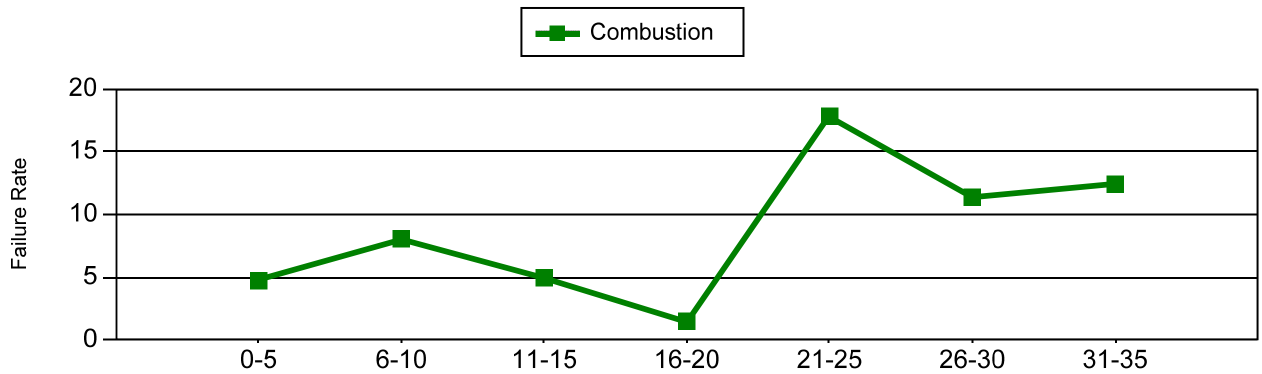


The effect of age on Failure Rate for different generating unit types based on 2005-2009 data.

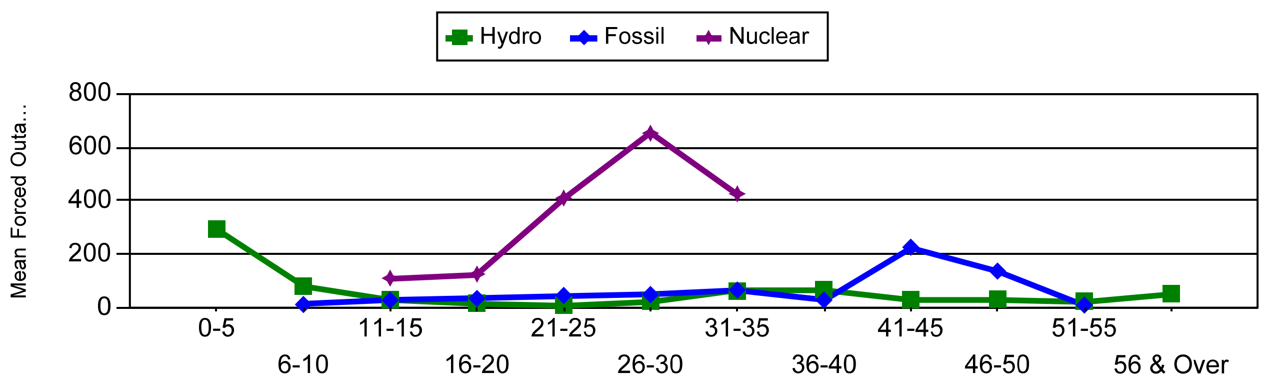
ALL CANADA Summary

External Causes Excluded, 2005 - 2009 Data

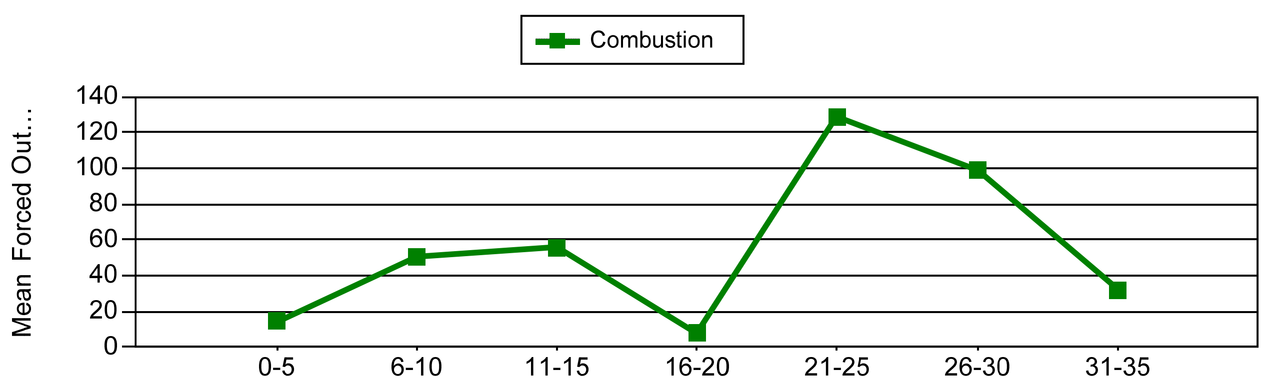
Table 5.2



The effect of age on Failure Rate for different generating unit types based on 2005-2009 data.



The effect of age on Mean Forced Outage Duration for different generating unit types based on 2005-2009 data.



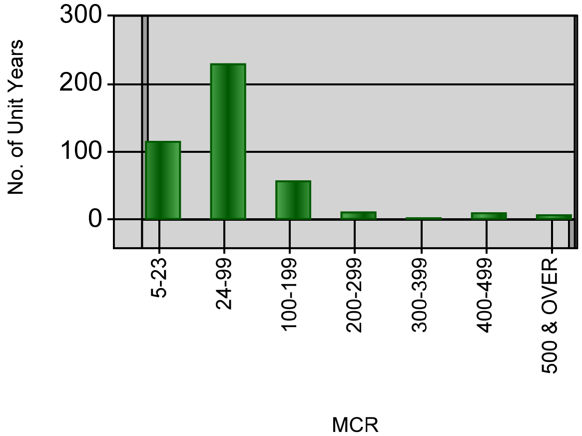
The effect of age on Mean Forced Outage Duration for different generating unit types based on 2005-2009 data.

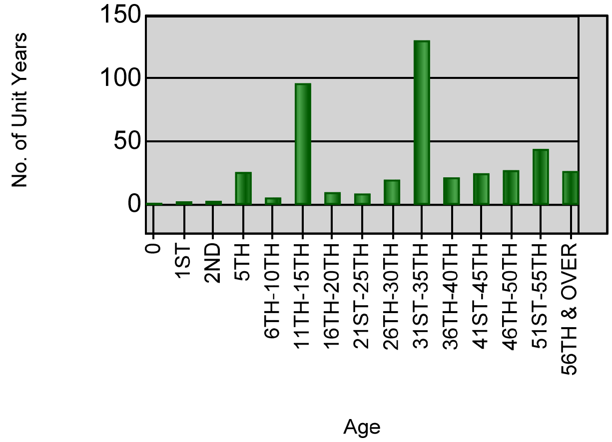
6.0 Generating Unit Statistics

6.1 Hydro Summary Statistics

Hydro Units
External Causes Excluded, 2009 Data

Table 6.1.1



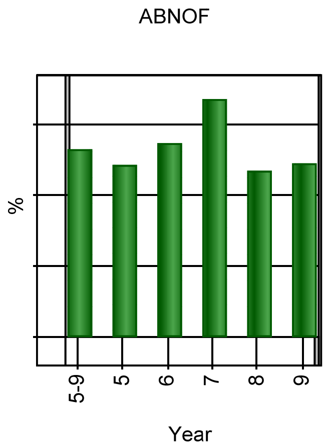


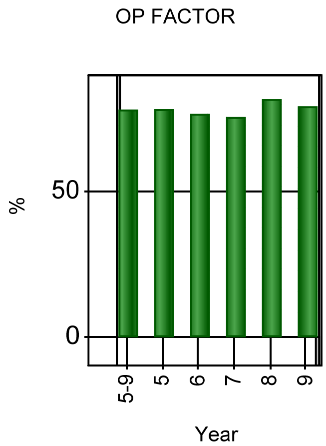
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
5-23	115.9	5.46	0.25	80.58	315	1.3	1663.98	35.35	1.26	1.29	1.29	9.7	7.85	2.30	1.04	5.74
24-99	230.0	14.21	7.62	76.47	561	2.9	4811.53	44.54	1.56	1.73	1.70	17.7	7.55	2.00	1.01	5.17
100-199	57.8	17.55	9.14	73.49	96	0.1	516.20	12.50	0.31	0.33	0.33	4.1	6.93	1.11	0.81	5.87
200-299	12.1	4.75	9.82	74.35	22	0.5	2772.18	188.38	5.00	5.32	5.30	2.6	21.11	1.34	4.45	12.48
300-399	2.0	22.98	0.00	68.45	13	0.0	226.05	26.82	2.81	2.86	2.83	0.2	8.18	6.53	0.60	5.56
400-499	11.0	14.07	12.00	69.76	19	0.1	181.88	25.96	0.73	1.07	1.04	1.8	16.35	2.34	1.57	13.92
500 & OVER	8.0	16.72	0.00	66.11	21	1.0	7246.67	415.34	15.84	15.84	15.71	1.4	17.17	3.21	0.89	3.83
Classification By Year Of Service																
0	0.9	34.66	0.00	28.74	2	0.0	136.18	98.42	8.23	8.23	8.13	0.3	36.41	8.04	6.96	26.86
1ST	2.7	13.76	0.00	66.77	27	0.1	880.68	37.84	6.00	6.00	5.83	0.5	19.21	14.25	5.12	9.82
2ND	3.0	27.84	0.00	69.42	3	0.0	284.38	95.35	1.54	1.54	1.49	0.1	2.74	1.44	0.50	1.15
5TH	26.0	0.19	0.00	85.02	87	1.3	4406.60	133.91	5.67	5.67	5.55	3.8	14.72	2.53	0.34	9.26
6TH-10TH	5.8	10.78	3.28	79.29	21	0.1	347.78	45.83	2.26	2.26	2.23	0.4	7.13	3.36	3.17	2.13
11TH-15TH	96.5	5.97	0.40	80.96	233	0.5	814.92	18.71	0.59	0.63	0.59	6.1	5.90	1.98	0.99	4.38
16TH-20TH	10.0	11.69	0.00	86.56	15	0.1	516.20	41.18	0.81	0.81	0.81	0.2	1.70	1.27	0.36	0.64
21ST-25TH	9.0	9.56	24.80	83.84	15	0.0	39.45	8.22	0.19	0.24	0.24	0.6	6.48	1.86	1.39	4.85
26TH-30TH	20.0	19.93	13.24	70.69	45	0.1	226.05	14.39	0.52	0.55	0.54	1.9	9.35	2.19	0.75	8.21
31ST-35TH	130.5	15.93	4.04	75.00	308	2.2	7246.67	62.25	2.16	2.26	2.2	11.1	8.40	2.02	1.08	5.56
36TH-40TH	21.8	13.16	5.08	76.78	43	0.2	673.98	40.27	1.15	1.15	1.15	2.0	9.21	1.47	1.87	6.43
41ST-45TH	25.1	22.82	19.96	63.85	49	0.7	2772.18	130.92	4.22	4.73	4.54	2.6	10.09	1.51	1.32	5.57
46TH-50TH	27.5	9.11	10.16	80.34	76	0.4	1250.17	42.37	1.60	1.81	1.79	2.5	8.80	2.08	1.14	6.17
51ST-55TH	44.3	12.60	2.77	78.77	92	0.3	365.27	31.21	0.91	0.93	0.92	3.2	7.04	1.32	0.77	5.53
56TH & OVER	26.8	9.54	16.76	73.20	58	0.4	2066.90	57.06	1.74	2.32	2.3	2.9	10.01	2.11	0.99	7.28
Classification By Operating Factor																
0-10	3.3	37.63	0.00	8.62	8	0.9	7246.67	990.52	71.67	67.73	66.34	1.0	19.93	11.60	1.22	0.61
11-20	6.2	37.00	1.89	18.60	13	0.0	78.02	21.24	2.75	5.93	3.92	1.8	23.12	3.36	1.03	20.94
21-30	11.8	51.56	4.94	26.31	36	0.2	272.42	39.65	4.94	4.71	4.56	1.8	14.15	5.61	1.30	11.54
31-40	21.1	40.56	5.18	35.19	61	0.6	2041.58	80.79	7.77	6.27	6.07	3.0	12.38	3.08	0.88	9.12
41-50	28.2	35.05	6.13	45.96	79	1.4	4811.53	160.40	11.65	11.02	10.87	4.9	17.14	2.18	1.81	9.70
51-60	24.7	20.04	5.51	56.54	79	0.8	2772.18	85.27	5.60	4.97	4.87	5.2	20.20	3.95	3.38	13.80
61-70	36.2	11.79	7.77	66.42	116	0.7	2066.90	55.87	3.93	2.92	2.91	6.5	17.11	2.52	1.33	13.65
71-80	46.0	10.69	5.03	76.36	115	0.5	1663.98	36.56	1.63	1.37	1.36	5.1	10.89	2.34	1.12	8.68
81-90	90.9	7.72	4.99	85.86	221	0.8	1250.17	33.01	1.36	1.12	1.10	4.9	5.35	1.82	1.26	3.12
91-100	181.3	1.18	6.02	96.38	346	0.5	578.10	13.41	0.40	0.33	0.33	3.9	2.14	1.60	0.48	1.34
All Units	**449.7**	**11.92**	**5.63**	**77.05**	**1074**	**6.5**	**7,246.67**	**52.69**	**1.77**	**1.88**	**1.87**	**38.2**	**8.24**	**2.00**	**1.07**	**5.67**

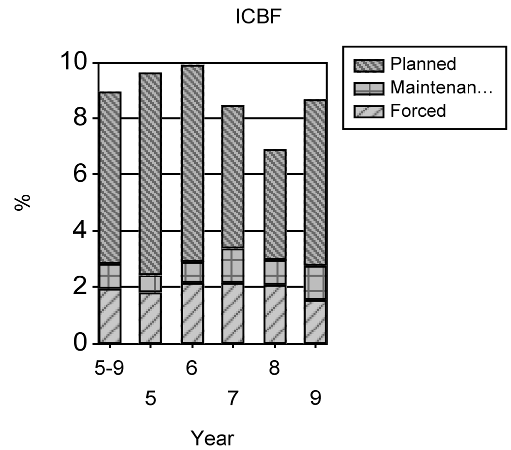
Hydro Units

Table 6.1.2

External Causes Excluded, 2005 to 2009





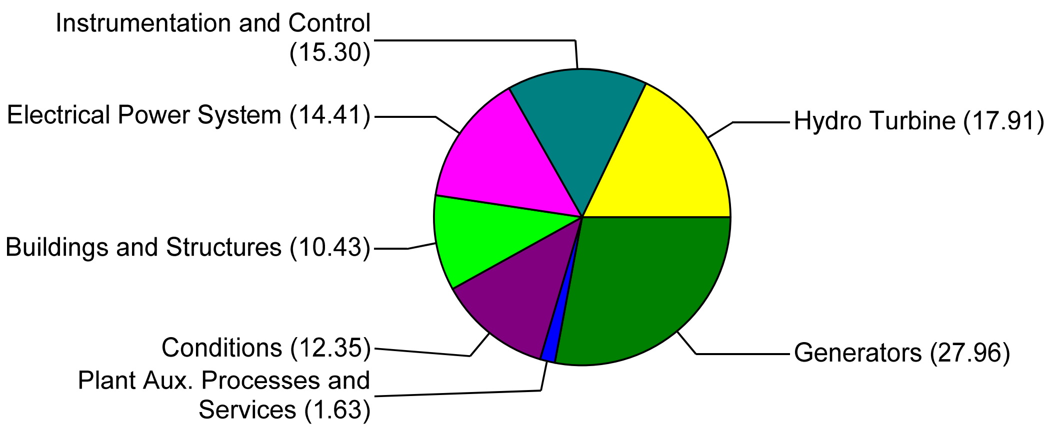


	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
5-23	676.9	10.31	0.44	74.75	1942	18.5	8137.21	83.32	3.29	3.36	3.35	61.4	8.48	2.50	0.86	5.01
24-99	1368.8	12.73	6.09	77.51	3734	15.9	5791.98	37.24	1.43	1.63	1.60	102.9	7.32	2.16	0.70	5.33
100-199	432.9	15.91	4.14	73.56	1163	3.0	2229.63	22.79	0.91	0.98	0.95	34.7	7.79	2.00	0.44	6.53
200-299	102.8	16.17	6.92	67.35	404	2.3	7314.50	49.59	3.19	3.42	3.39	16.8	16.29	2.59	1.33	12.57
300-399	53.9	22.81	0.00	65.64	359	0.4	371.33	10.89	1.24	1.25	1.24	6.2	11.46	3.75	0.47	10.16
400-499	58.1	15.39	9.26	71.23	116	0.5	1947.65	38.91	1.20	1.58	1.53	7.4	12.60	2.13	0.85	10.59
500 & OVER	40.0	12.87	0.00	75.69	106	1.8	7246.67	146.66	5.53	5.53	5.50	4.6	11.43	3.10	1.12	5.88
Classification By Year Of Service																
0	4.7	10.19	0.00	71.11	19	0.1	162.30	25.85	1.65	1.65	1.64	0.9	18.41	3.60	1.35	15.86
1ST	36.7	4.06	0.00	79.86	130	3.3	8759.98	224.10	10.10	10.36	3.72	5.7	15.43	3.89	1.47	4.76
2ND	36.1	16.77	0.46	65.63	102	4.4	6206.98	377.20	15.58	15.59	11.57	6.2	17.17	3.11	0.76	4.28
3RD	29.4	7.30	0.39	74.54	105	4.0	8759.98	334.26	15.44	15.44	12	5.3	17.92	3.83	0.47	3.84
4TH	27.8	1.92	0.70	87.68	86	2.3	8783.98	235.84	8.55	8.58	5.05	2.7	9.57	2.80	0.30	1.00
5TH	29.9	0.26	0.62	82.74	129	2.4	7832.23	166.03	8.96	8.96	7.77	5.0	16.73	3.59	0.35	8.22
6TH-10TH	172.8	6.07	0.13	77.24	565	5.3	8137.21	81.73	3.45	3.56	2.72	14.8	7.82	2.99	1.33	3.62
11TH-15TH	540.6	13.14	0.61	73.01	1524	7.1	5402.25	40.83	1.65	1.70	1.55	42.2	7.29	2.22	0.69	5.33
16TH-20TH	61.2	14.06	1.69	71.80	192	0.5	516.20	20.69	0.98	0.98	0.95	6.2	9.76	2.22	0.42	8.63
21ST-25TH	109.5	18.03	6.32	72.54	402	0.5	394.21	11.07	0.63	0.67	0.66	10.0	9.10	2.30	0.41	8.20
26TH-30TH	759.3	13.16	3.97	75.44	2343	6.9	2919.03	25.88	1.16	1.24	1.1	65.2	8.30	2.53	0.53	6.76
31ST-35TH	322.0	14.35	3.72	77.20	740	6.0	7246.67	70.84	2.33	2.45	1.94	25.5	7.88	1.86	0.88	5.04
36TH-40TH	125.8	21.06	7.87	69.43	291	2.5	7314.50	76.30	2.80	3.00	2.54	11.5	9.06	1.75	1.14	5.77
41ST-45TH	100.6	17.46	15.02	73.17	405	1.4	2772.18	29.82	1.78	2.13	2	6.6	6.38	3.34	0.97	3.81
46TH-50TH	207.4	13.76	4.95	77.88	492	1.9	1848.21	34.65	1.18	1.29	1.27	16.3	7.83	1.39	0.67	6.13
51ST-55TH	136.5	9.02	3.72	83.11	248	0.8	598.35	28.06	0.68	0.81	0.78	8.7	6.25	1.23	0.72	4.84
56TH & OVER	120.7	8.80	18.55	78.76	328	2.0	2336.75	52.48	1.95	2.94	2.89	12.3	9.83	2.45	0.73	6.73
Classification By Operating Factor																
0-10	9.0	10.35	0.26	3.73	19	1.9	7832.23	862.61	83.20	82.16	82.03	7.4	68.57	37.04	0.28	51.05
11-20	38.6	35.49	2.23	18.11	153	4.7	8783.98	270.85	33.66	33.63	33.19	10.6	20.15	7.06	0.68	10.32
21-30	83.8	51.16	2.96	25.99	332	3.0	5402.25	79.86	11.25	11.54	11.14	13.1	14.22	5.66	0.83	10.01
31-40	86.3	40.83	3.50	36.25	347	2.4	2336.75	59.82	6.60	6.86	6.74	15.1	16.30	3.49	1.30	12.33
41-50	84.1	29.75	5.73	46.51	334	3.6	8137.21	94.11	7.91	7.85	7.73	13.7	14.84	4.68	0.75	10.14
51-60	169.3	24.93	3.90	56.27	744	4.4	7812.66	52.15	4.14	4.06	4.00	18.9	10.17	3.65	0.91	6.87
61-70	389.1	18.26	3.57	66.09	1425	10.4	7246.67	63.79	3.73	3.90	3.80	47.0	11.58	3.06	0.89	7.99
71-80	469.8	11.38	3.21	76.06	1491	10.2	6928.63	59.83	2.69	2.81	2.75	45.2	9.29	2.61	1.04	5.96
81-90	848.4	6.67	4.08	86.31	2018	7.5	3390.77	32.52	1.01	1.17	1.16	52.9	6.17	1.86	0.59	4.54
91-100	642.9	1.44	5.44	95.01	1238	3.3	1637.53	23.61	0.55	0.61	0.60	21.3	3.30	1.65	0.43	2.29
All Units	**2821.2**	**12.81**	**4.11**	**75.53**	**8101**	**51.4**	**8,783.98**	**55.58**	**2.27**	**2.41**	**2.38**	**245.2**	**8.40**	**2.31**	**0.73**	**5.78**

Hydro Units — Table 6.1.3

Major Component Outage Code Report, 2005 to 2009

Major Componenent Contribution to Hydro Unit ICbF based on 2005-2009 data.



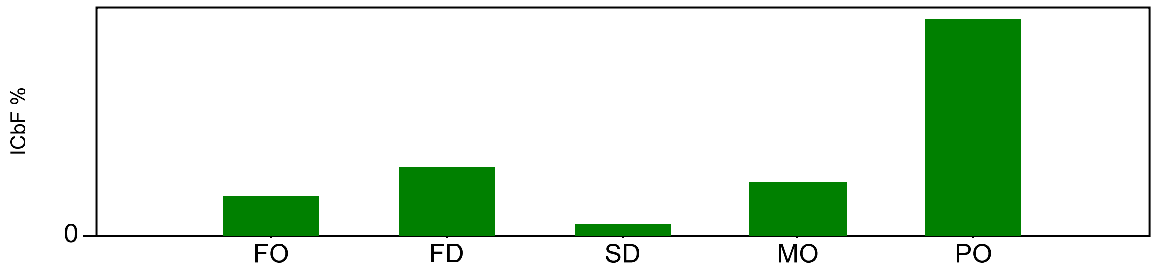
UNIT STATISTICS

Number of Units:	796.00
Number of Unit Yars:	2941.44
Overall Operating Factor:	75.60

MAJOR COMPONENT	FORCED OUTAGES NO. OCC.	FORCED OUTAGES ICBF (%)	FORCED DERATINGS NO. OCC.	FORCED DERATINGS ICBF (%)	SCHEDULED DERATINGS NO. OCC.	SCHEDULED DERATINGS ICBF (%)	MAINTENANCE OUTAGES NO. OCC.	MAINTENANCE OUTAGES ICBF (%)	PLANNED OUTAGES NO. OCC.	PLANNED OUTAGES ICBF (%)	CONTRIBUTION TO UNIT ICBF (%)	CONTRIBUTION TO UNIT FOR (%)	CONTRIBUTION TO UNIT DAFOR (%)
Buildings and Structures	286	0.09	1734	0.18	168	0.02	1378	0.13	1018	0.57	0.96	0.09	0.13
Conditions	1381	0.09	1197	0.10	750	0.05	971	0.07	995	0.15	0.35	0.06	0.08
Electrical Power System	1050	0.20	371	0.04	48	0.01	1251	0.14	1532	0.54	0.97	0.29	0.29
Generators	1790	0.53	2389	0.23	69	0.05	2385	0.20	2711	2.44	3.39	0.65	0.69
Hydro Turbine	1807	0.74	460	0.11	64	0.01	1332	0.20	1583	1.84	2.92	0.94	0.95
Instrumentation and Control	2118	0.17	357	0.04	53	0.00	1036	0.04	965	0.35	0.62	0.22	0.22
Plant Aux. Processes and Services	174	0.03	8	0.01	0	0.00	169	0.00	84	0.02	0.07	0.05	0.05
TOTAL (External Causes Included)	8606	1.85	6516	0.71	1152	0.14	8522	0.78	8888	5.91	9.28	2.30	2.41
TOTAL (External Causes Excluded)	7354	1.91	5320	0.67	402	0.12	7565	0.84	7954	6.06	9.25	2.28	2.37

Hydro Units
Major Component Outage Code Report, 2005 to 2009

Table 6.1.4
Buildings and Structure



Buildings and Structures ICbF by event type forHydro units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

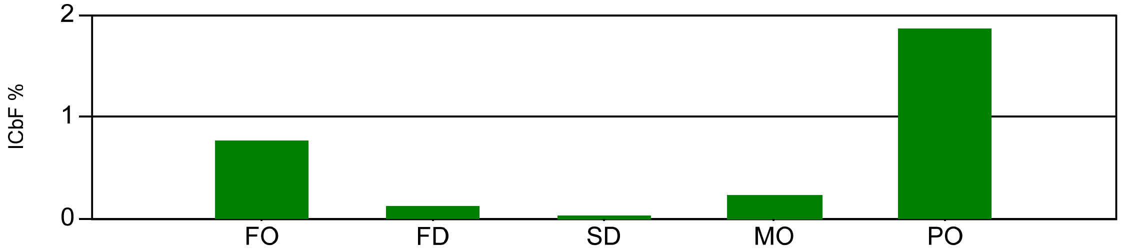
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Buildings and Structures													
22100	Powerhouse Substructure	9	0.00	0	0.00	34	0.00	32	0.00	30	0.01	0.02	0.00
22110	Draft Tubes (Concrete)	1	0.00	0	0.00	1	0.00	29	0.00	3	0.00	0.00	0.00
22121	Scroll Case (Concrete)	2	0.00	0	0.00	0	0.00	10	0.00	7	0.00	0.00	0.00
26000	Water And Earth Retaining Structures	1	0.00	0	0.00	1	0.00	0	0.00	11	0.00	0.00	0.00
26100	Main Dam And Associated Wingwalls - Concrete	0	0.00	0	0.00	1	0.00	2	0.00	4	0.01	0.01	0.00
26200	Main Dam And Associated Wingwalls - Earth And Rock Fill	0	0.00	0	0.00	0	0.00	15	0.00	2	0.01	0.01	0.00
29200	Channels & Tunnels	0	0.00	2	0.00	1	0.00	7	0.00	19	0.01	0.01	0.00
29210	Intake (Headrace) Channel	21	0.02	26	0.00	0	0.00	79	0.01	52	0.01	0.04	0.03
29250	Tailrace (Channel)	10	0.00	6	0.00	4	0.00	354	0.02	46	0.02	0.04	0.00
29260	Tunnels (Including Shafts And Pipelines)	3	0.00	9	0.00	0	0.00	9	0.02	23	0.05	0.08	0.00
29270	Dewatering Structure (Tunnel)	1	0.00	0	0.00	4	0.00	12	0.00	1	0.00	0.00	0.00
29300	Intake Structures Or Control Structures	58	0.01	13	0.02	4	0.00	73	0.01	140	0.10	0.13	0.02
29320	Intake Sectional Service Gates And Followers (Also Stop Logs)	7	0.00	0	0.00	3	0.00	44	0.01	43	0.01	0.02	0.00
29330	Trash Racks And Followers	57	0.03	113	0.03	69	0.01	342	0.02	212	0.02	0.09	0.04
29400	Sluiceway And Spillway (Concrete)	0	0.00	1	0.00	0	0.00	10	0.00	1	0.00	0.00	0.00
29420	Sluice Gates (Power Operated)	2	0.00	6	0.00	10	0.00	12	0.00	2	0.00	0.01	0.00
29440	Fishladders And Log Chutes	0	0.00	2	0.00	0	0.00	4	0.00	6	0.00	0.00	0.00
29500	Headworks	4	0.00	0	0.00	1	0.00	67	0.00	119	0.06	0.07	0.00
29550	Headgates	69	0.01	10	0.00	30	0.00	226	0.01	174	0.19	0.21	0.01
29620	Penstock	25	0.02	1546	0.13	3	0.01	37	0.03	105	0.05	0.20	0.03
29626	Penstock Relief Valve	9	0.00	0	0.00	2	0.00	7	0.00	9	0.02	0.02	0.00
29800	Surge Tanks And Chambers	7	0.00	0	0.00	0	0.00	6	0.00	9	0.00	0.00	0.00
29900	Pump Storage Reservoirs	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
Buildings and Structures Total		**286**	**0.09**	**1734**	**0.18**	**168**	**0.02**	**1378**	**0.13**	**1018**	**0.57**	**0.96**	**0.13**

Hydro Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.1.4

Hydro Turbines



Hydro Turbine ICbF by event type forHydro units based on 2005-2009 data.

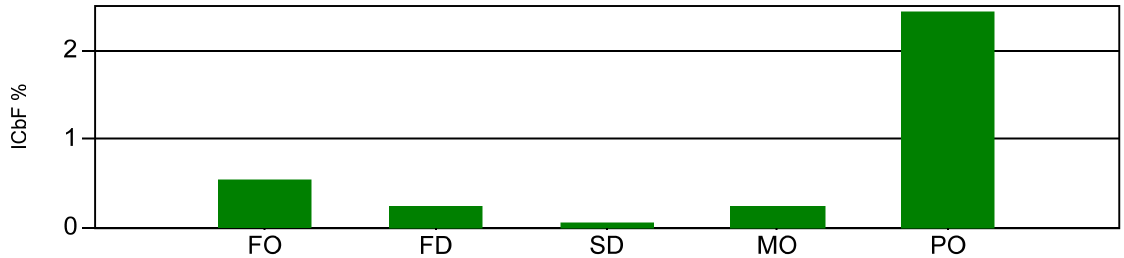
UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Hydro Turbine													
41100	Turbines	75	0.22	31	0.02	8	0.00	201	0.03	574	1.08	1.34	0.28
41105	Turbine Aeration Equipment	2	0.00	0	0.00	0	0.00	10	0.00	7	0.00	0.00	0.00
41110	Runner	43	0.05	36	0.02	41	0.00	126	0.11	253	0.39	0.56	0.06
41111	Hub	1	0.04	0	0.00	0	0.00	1	0.00	2	0.03	0.08	0.05
41112	Blades	6	0.04	2	0.00	0	0.00	15	0.00	18	0.01	0.06	0.05
41113	Cone	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
41120	Head Cover	14	0.05	71	0.01	0	0.00	11	0.00	5	0.02	0.08	0.07
41122	Turbine Guide Bearing	185	0.07	30	0.01	2	0.00	86	0.01	58	0.03	0.12	0.09
41123	Turbine Guide Bearing Oil System	63	0.01	0	0.00	0	0.00	36	0.00	20	0.00	0.01	0.01
41124	Turbine Guide Bearing Cooling Equipment	34	0.00	0	0.00	0	0.00	28	0.00	11	0.00	0.01	0.00
41125	Head Cover Drainage	35	0.01	6	0.00	0	0.00	11	0.00	10	0.00	0.01	0.01
41130	Turbine Regulation	32	0.01	0	0.00	0	0.00	22	0.00	45	0.02	0.03	0.01
41132	Wicket Gate (Guidevanes)	30	0.05	3	0.00	0	0.00	23	0.00	20	0.01	0.06	0.07
41133	Wicket Linkage (Including Shear Pin)	271	0.09	88	0.00	1	0.00	80	0.01	19	0.01	0.11	0.12
41139	Nozzle Assembly	1	0.00	1	0.00	0	0.00	2	0.00	12	0.00	0.00	0.00
41140	Scroll Case	6	0.00	0	0.00	0	0.00	19	0.00	4	0.00	0.01	0.00
41145	Pit Liner	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41150	Turbine Shaft	7	0.00	3	0.00	0	0.00	10	0.00	2	0.00	0.00	0.00
41151	Shaft Seal (Packing, Carbon Seal, Etc.)	43	0.01	170	0.05	0	0.01	71	0.01	46	0.04	0.09	0.01
41160	Inlet Valve	93	0.00	0	0.00	2	0.00	77	0.01	75	0.05	0.06	0.00
41171	Draft Tube Liner	2	0.00	0	0.00	0	0.00	3	0.00	8	0.00	0.00	0.00
41180	Greasing System	2	0.00	0	0.00	0	0.00	30	0.00	13	0.00	0.01	0.00
41700	Governor System	302	0.03	7	0.00	4	0.00	147	0.01	165	0.06	0.10	0.03
41710	Governor	265	0.02	6	0.00	0	0.00	184	0.01	148	0.06	0.10	0.03
41711	Governor Head	2	0.00	0	0.00	1	0.00	10	0.00	3	0.00	0.00	0.00
41712	Governor Gain	0	0.00	0	0.00	0	0.00	14	0.00	0	0.00	0.00	0.00
41713	Speed Detection	46	0.00	3	0.00	1	0.00	17	0.00	7	0.00	0.00	0.00
41714	Governor Feedback	19	0.00	1	0.00	0	0.00	3	0.00	3	0.00	0.00	0.00
41715	Governor Auxiliary Systems	105	0.02	1	0.00	4	0.00	48	0.00	34	0.03	0.06	0.03
41720	Governor Oil Pumps	76	0.01	1	0.00	0	0.00	18	0.00	6	0.00	0.01	0.02
41740	Governor Oil Piping	5	0.00	0	0.00	0	0.00	6	0.00	6	0.00	0.00	0.00
41741	Governor Oil Piping System - Components	17	0.01	0	0.00	0	0.00	8	0.00	8	0.00	0.01	0.01
41742	Governor Oil Piping System - Leakage	17	0.00	0	0.00	0	0.00	10	0.00	1	0.00	0.00	0.00
41743	Governor Oil Piping System - Filters	7	0.00	0	0.00	0	0.00	4	0.00	0	0.00	0.00	0.00
Hydro Turbine Total		**1807**	**0.74**	**460**	**0.11**	**64**	**0.01**	**1332**	**0.20**	**1583**	**1.84**	**2.92**	**0.95**

Hydro Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.1.4
Generators



Generators ICbF by event type forHydro units based on 2005-2009 data.

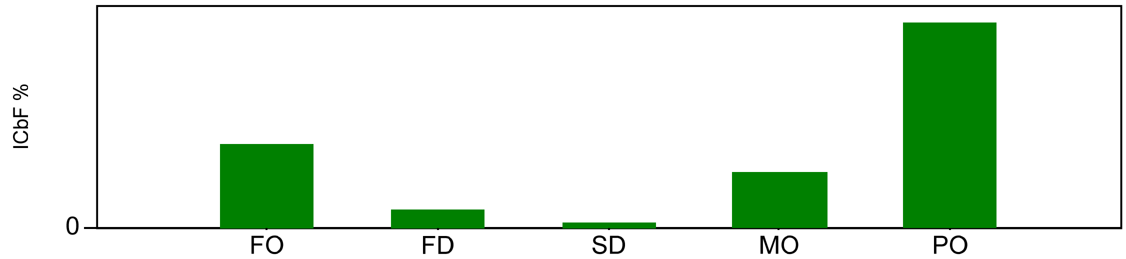
UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Generators													
42100	Generators	233	0.12	18	0.00	27	0.00	429	0.05	1526	1.74	1.91	0.15
42110	Generator Rotor	45	0.01	22	0.00	0	0.00	56	0.00	67	0.13	0.15	0.01
42111	Braking/Jacking System	99	0.01	0	0.00	0	0.00	71	0.00	57	0.02	0.03	0.01
42112	Brake Pneumatic System	25	0.01	0	0.00	0	0.00	20	0.00	8	0.00	0.02	0.02
42113	Pole Windings And Connections	18	0.02	3	0.00	1	0.00	25	0.01	15	0.02	0.05	0.03
42114	Slip Rings And Commutator	10	0.01	0	0.00	1	0.00	118	0.01	39	0.01	0.02	0.01
42115	Brushes And Brush Rigging	51	0.01	1	0.00	3	0.00	918	0.07	212	0.10	0.17	0.01
42120	Generator Stator	59	0.03	1070	0.10	7	0.01	34	0.01	197	0.18	0.31	0.04
42121	Generator Stator Terminals	0	0.00	0	0.00	0	0.00	3	0.00	1	0.00	0.00	0.00
42123	Generator Stator Winding	28	0.08	940	0.09	14	0.04	52	0.02	29	0.12	0.27	0.09
42124	Generator Stator Winding Wedges	1	0.00	0	0.00	0	0.00	1	0.00	4	0.01	0.01	0.00
42125	Core Iron	4	0.00	0	0.00	1	0.00	5	0.00	2	0.00	0.01	0.00
42126	Generator Stator Cooling System	23	0.00	82	0.01	6	0.00	40	0.01	20	0.00	0.02	0.01
42170	Thrust And Guide Bearings	117	0.03	17	0.00	1	0.00	56	0.01	21	0.01	0.05	0.04
42171	Thrust Bearing	70	0.08	4	0.00	0	0.00	24	0.00	6	0.00	0.08	0.10
42172	Thrust Bearing Oil System	48	0.00	2	0.00	0	0.00	35	0.00	9	0.01	0.01	0.00
42174	Thrust Bearing Oil Lift System	18	0.00	0	0.00	0	0.00	9	0.00	4	0.00	0.00	0.00
42176	Guide Bearing	32	0.01	190	0.02	0	0.00	9	0.00	2	0.00	0.03	0.02
42177	Guide Bearing Oil System	14	0.00	0	0.00	0	0.00	14	0.00	10	0.00	0.01	0.00
42178	Bearing Oil Cooling System	45	0.01	2	0.00	0	0.00	31	0.00	2	0.00	0.01	0.01
42200	Excitation	436	0.06	28	0.00	8	0.00	218	0.01	196	0.05	0.12	0.08
42210	Exciter Transformer	15	0.00	0	0.00	0	0.00	25	0.00	16	0.00	0.01	0.00
42220	Static Exciter(Thyristors, Diodes, Etc.)	88	0.01	2	0.00	0	0.00	66	0.00	71	0.01	0.03	0.02
42230	Field Breaker	128	0.01	0	0.00	0	0.00	58	0.00	28	0.01	0.02	0.01
42240	Rotating Exciters	9	0.00	0	0.00	0	0.00	21	0.00	7	0.00	0.00	0.00
42260	Automatic Voltage Regulators	174	0.02	8	0.01	0	0.00	47	0.00	162	0.02	0.05	0.03
Generators Total		**1790**	**0.53**	**2389**	**0.23**	**69**	**0.05**	**2385**	**0.20**	**2711**	**2.44**	**3.39**	**0.69**

Hydro Units — Table 6.1.4

Detail Component Outage Code Report, 2005 to 2009 — Elec. Power Sys.



Electrical Power System ICbF by event type forHydro units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Electrical Power System													
51100	Output System Generator Voltage	80	0.02	10	0.00	0	0.00	83	0.02	75	0.03	0.08	0.03
51120	Generator Power Transformers	282	0.06	296	0.04	13	0.01	361	0.08	656	0.17	0.33	0.07
51130	Switching Equipment - Generator Voltage	15	0.00	0	0.00	0	0.00	25	0.00	34	0.03	0.04	0.01
51133	Circuit Breakers - Generator Voltage	349	0.05	9	0.00	5	0.00	347	0.02	357	0.18	0.25	0.07
51136	Disconnect Switches - Generator Voltage	71	0.01	2	0.00	4	0.00	125	0.01	155	0.04	0.06	0.02
51150	Bus Duct, Bus, Cable	82	0.06	28	0.00	6	0.00	108	0.01	131	0.08	0.16	0.08
51151	Bus Duct Cooling System	10	0.00	24	0.00	7	0.00	11	0.00	5	0.00	0.00	0.00
51170	Generator Neutral Grounding Equipment	6	0.00	0	0.00	0	0.00	3	0.00	5	0.00	0.01	0.01
52100	Generator Voltage Supply System	33	0.00	0	0.00	1	0.00	25	0.00	30	0.00	0.01	0.00
52120	Station Service Transformer	25	0.00	0	0.00	4	0.00	67	0.00	15	0.00	0.00	0.00
52130	Unit Service Transformer	9	0.00	2	0.00	4	0.00	11	0.00	13	0.01	0.01	0.00
53000	Station Power Distribution	59	0.00	0	0.00	4	0.00	63	0.00	40	0.00	0.01	0.00
55000	Direct Current Power Supplies	29	0.00	0	0.00	0	0.00	22	0.00	16	0.00	0.01	0.00
Electrical Power System Total		**1050**	**0.20**	**371**	**0.04**	**48**	**0.01**	**1251**	**0.14**	**1532**	**0.54**	**0.97**	**0.29**

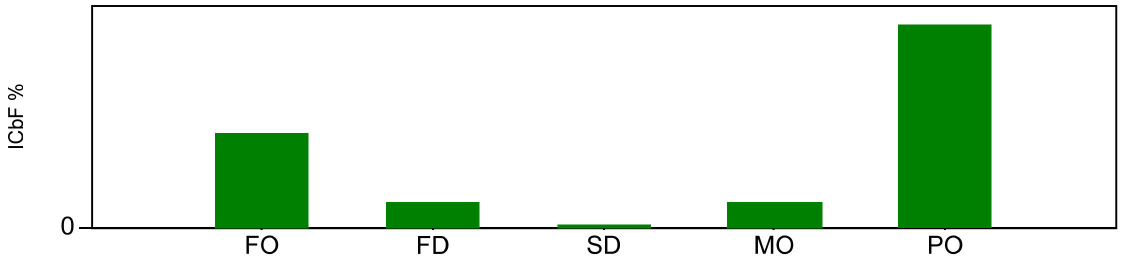
Canadian Electricity Association
Association canadienne de l'électricité

Hydro Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.1.4

Ins. And Controls



Instrumentation and Control ICbF by event type forHydro units based on 2005-2009 data.

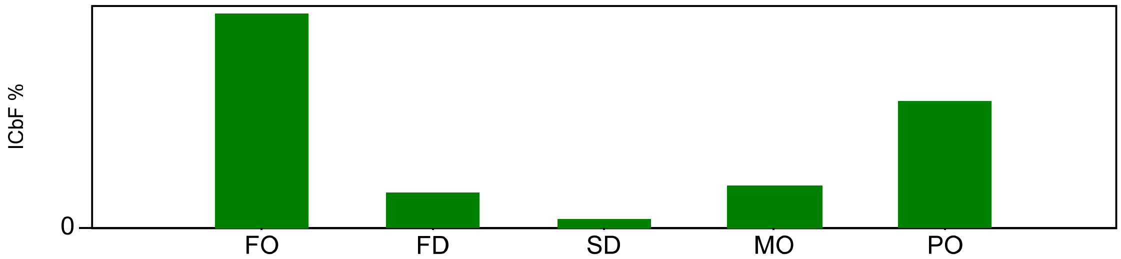
UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Instrumentation and Control													
64100	Hydraulic Turbine And Auxiliaries - Instruments & Control	100	0.02	6	0.00	8	0.00	64	0.01	29	0.01	0.04	0.03
64112	Turbine Guide Bearing - Instruments	27	0.01	105	0.01	0	0.00	15	0.00	4	0.00	0.02	0.01
64170	Governor - Instruments And Controls	162	0.01	3	0.02	0	0.00	81	0.01	44	0.00	0.04	0.01
64171	Governor Oil System - Instruments And	50	0.01	0	0.00	0	0.00	7	0.00	4	0.00	0.01	0.01
64200	Generator And Auxiliaries -	442	0.06	132	0.01	20	0.00	230	0.01	188	0.08	0.16	0.07
64210	Supervisory Control & Data Acquisition -	134	0.01	16	0.00	3	0.00	119	0.01	17	0.01	0.02	0.01
64211	Generator Brakes - Instruments And	28	0.00	0	0.00	0	0.00	26	0.00	0	0.00	0.00	0.00
64216	Generator Thrust Bearing - Instruments	24	0.00	2	0.00	0	0.00	11	0.00	4	0.00	0.00	0.00
64217	Generator Guide Bearing - Instruments & Control	22	0.00	12	0.00	0	0.00	8	0.00	3	0.00	0.01	0.00
64220	Excitation Instrumentation & Control	113	0.00	0	0.00	2	0.00	63	0.00	35	0.00	0.01	0.01
64260	Synchronous Condensor - Instrumentation & Control	9	0.00	0	0.00	4	0.00	6	0.00	20	0.00	0.01	0.00
65100	Main Power Output Systems -	142	0.01	5	0.00	4	0.00	57	0.00	76	0.01	0.02	0.01
65200	Station Service Main Transformation - Instruments & Control	21	0.01	1	0.00	0	0.00	10	0.00	11	0.01	0.01	0.01
65300	Station Service Power Distribution - Instruments & Control	48	0.00	0	0.00	1	0.00	33	0.00	35	0.04	0.04	0.00
65500	Direct Current Power Supplies - Instruments & Control	23	0.00	0	0.00	0	0.00	9	0.00	7	0.00	0.00	0.00
65900	System Control	256	0.01	4	0.00	1	0.00	189	0.00	363	0.14	0.15	0.02
66000	Telecom and Communications	478	0.02	71	0.00	1	0.00	86	0.00	115	0.05	0.08	0.03
67000	Plant Auxiliary Processes And Services - Instruments & Control	39	0.00	0	0.00	9	0.00	22	0.00	10	0.00	0.00	0.00
Instrumentation and Control Total		**2118**	**0.17**	**357**	**0.04**	**53**	**0.00**	**1036**	**0.04**	**965**	**0.35**	**0.62**	**0.22**

Hydro Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.1.4
Aux. Processes



Plant Aux. Processes and Services ICbF by event type forHydro units based on 2005-2009 data.

UNIT STATISTICS

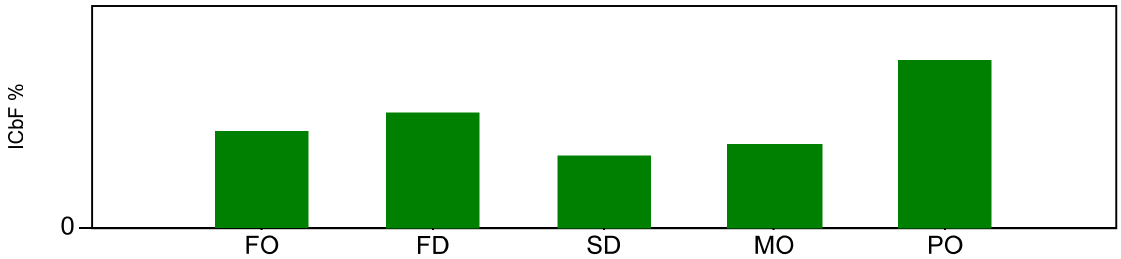
Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Plant Aux. Processes and Services													
72300	Cooling Water Systems	114	0.02	6	0.01	0	0.00	92	0.00	48	0.02	0.05	0.03
72400	Fire Protection Water System	39	0.01	0	0.00	0	0.00	58	0.00	25	0.00	0.02	0.02
72600	Turbine Dewatering & Rewatering Piping System	2	0.00	0	0.00	0	0.00	6	0.00	6	0.00	0.00	0.00
75000	Compressed Air To Brakes & Governor	16	0.00	1	0.00	0	0.00	3	0.00	5	0.00	0.00	0.00
75140	Water Depressing System	3	0.00	1	0.00	0	0.00	8	0.00	0	0.00	0.00	0.00
75220	Fixed Fire Protection CO2 & Halon System	0	0.00	0	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
Plant Aux. Processes and Services Total		**174**	**0.03**	**8**	**0.01**	**0**	**0.00**	**169**	**0.00**	**84**	**0.02**	**0.07**	**0.05**

Hydro Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.1.4
Conditions



Conditions ICbF by event type forHydro units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	796.00
Number of Unit Years:	2941.44
Overall Operating Factor:	75.60

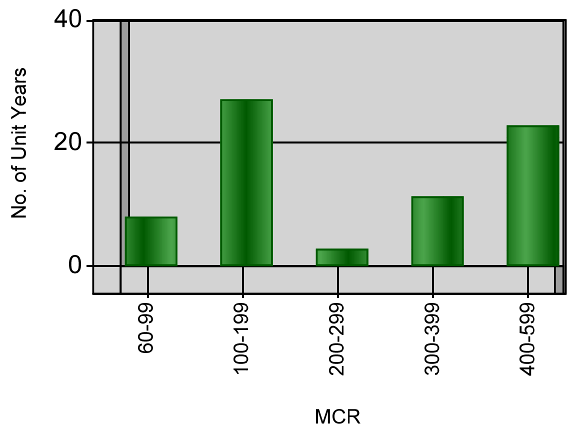
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
00500	Regulatory Bodies	12	0.01	662	0.03	59	0.01	365	0.02	249	0.03	0.06	0.01
05200	Transmission Limitations	540	0.02	258	0.01	114	0.01	317	0.03	292	0.05	0.09	0.02
05201	Powerhouse Substation (non-generating unit equipment)	8	0.00	1	0.00	0	0.00	10	0.00	32	0.02	0.03	0.00
05202	Transmission Line (connected to powerhouse substation)	84	0.00	0	0.00	0	0.00	3	0.00	17	0.00	0.00	0.00
05203	Transmission Equipment (beyond transmission line)	35	0.00	0	0.00	0	0.00	0	0.00	10	0.00	0.00	0.00
07010	Site Environment, Storms, Floods	226	0.01	14	0.01	1	0.00	15	0.00	47	0.00	0.01	0.00
07060	Upstream Water Conditions	33	0.01	80	0.02	508	0.03	33	0.01	5	0.01	0.05	0.01
07070	Downstream Water Conditions	4	0.00	9	0.00	63	0.00	31	0.00	52	0.01	0.02	0.00
07080	Headpond Ice Cover	95	0.03	24	0.01	0	0.00	15	0.00	0	0.00	0.03	0.03
08160	Fire, General	9	0.00	0	0.00	1	0.00	1	0.00	2	0.00	0.00	0.00
08910	Staff Shortage	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
08940	Labour Troubles	2	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
99999	Other	333	0.01	149	0.02	4	0.00	180	0.01	289	0.03	0.06	0.01
Conditions Total		**1381**	**0.09**	**1197**	**0.10**	**750**	**0.05**	**971**	**0.07**	**995**	**0.15**	**0.35**	**0.08**

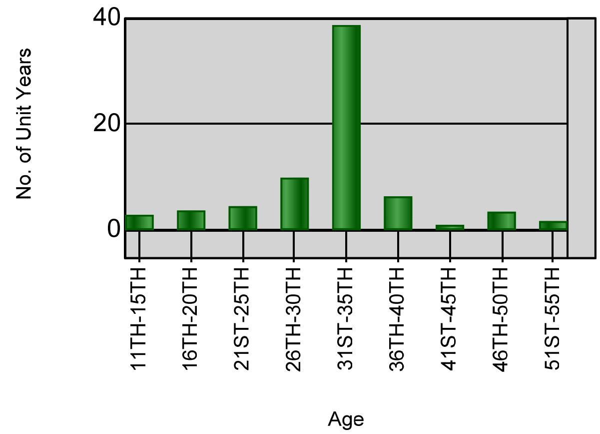
6.2 Fossil Summary Statistics

Fossil Units

External Causes Excluded, 2009 Data

Table 6.2.1

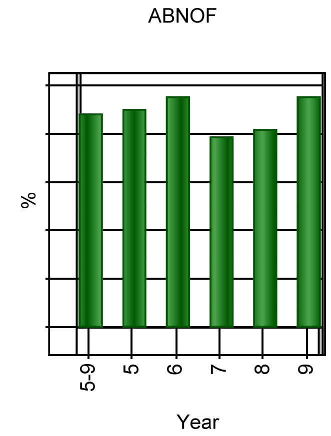


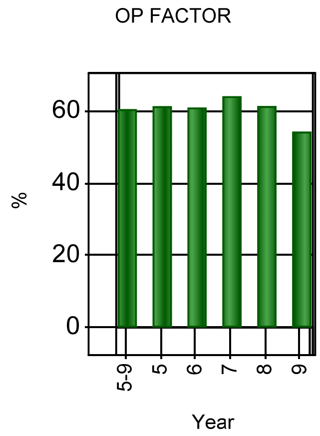


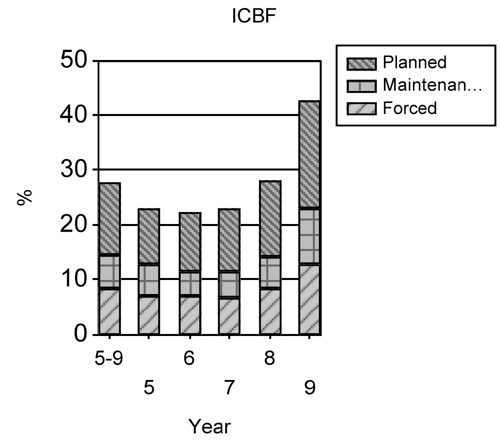
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	8.1	21.20	0.00	36.53	62	1.0	2148.48	147.78	20.89	42.42	41.14	4.3	47.90	11.86	2.57	17.67
100-199	27.1	24.18	2.29	54.16	139	0.9	1781.35	55.27	5.23	9.11	8.39	5.9	21.09	7.74	1.63	13.86
200-299	2.8	18.93	0.00	62.63	29	0.2	321.83	45.79	6.95	10.10	9.91	0.5	15.74	11.82	0.72	7.61
300-399	11.4	15.79	0.00	59.92	95	0.5	422.25	49.52	5.43	20.48	20.37	3.5	26.71	9.42	0.03	7.91
400-599	22.9	23.70	0.00	44.53	213	1.6	2850.15	67.67	11.48	16.41	15.58	6.7	26.59	10.18	7.00	9.40
Classification By Year Of Service																
11TH-15TH	2.9	0.00	0.00	90.91	15	0.1	165.02	36.18	2.15	4.41	4.4	0.2	8.26	4.26	0.15	3.86
16TH-20TH	3.7	0.00	0.00	85.50	37	0.1	132.10	26.67	2.96	13.27	13.2	0.7	18.67	10.02	3.09	1.75
21ST-25TH	4.5	11.99	0.00	67.17	30	0.1	188.95	38.30	3.31	5.41	5.35	0.6	12.89	6.13	0.28	8.28
26TH-30TH	9.9	11.73	4.28	59.61	78	0.3	321.83	39.07	4.37	15.92	15.78	3.2	28.84	8.55	2.43	13.22
31ST-35TH	38.7	31.27	0.42	40.43	283	2.5	2850.15	77.39	12.11	17.74	16.62	10.9	26.46	10.64	4.22	12.25
36TH-40TH	6.4	19.20	0.00	61.00	57	0.1	161.23	21.71	2.85	9.95	9.88	1.1	15.86	11.42	1.50	7.26
41ST-45TH	1.0	6.49	0.00	47.46	5	0.3	1927.08	475.42	36.38	37.65	37.65	0.5	46.99	6.32	13.14	5.77
46TH-50TH	3.5	19.45	0.00	15.82	25	0.7	2148.48	236.93	41.49	69.24	64.48	2.6	64.36	14.68	0.57	34.53
51ST-55TH	1.7	15.89	0.00	61.40	8	0.0	89.65	15.72	0.91	35.40	35.04	1.0	49.86	5.13	3.43	2.85
Classification By Operating Factor																
0-10	12.7	62.13	1.32	4.75	36	0.7	2148.48	179.61	59.19	57.76	44.53	4.1	31.76	22.73	2.52	22.59
11-20	5.7	57.32	0.00	14.59	41	0.1	622.53	32.04	13.54	22.82	19.14	1.5	24.76	21.06	5.82	14.21
21-30	5.8	43.71	0.00	25.83	31	0.6	2850.15	174.24	35.44	29.76	29.11	1.7	27.64	9.03	9.02	7.02
31-40	6.3	19.04	6.58	35.24	58	0.4	1026.72	63.76	12.20	16.58	15.99	2.6	36.69	13.88	6.08	21.84
41-50	4.9	11.18	0.00	44.40	37	0.5	1927.08	107.96	10.98	17.36	16.90	1.9	31.64	5.68	6.47	12.05
51-60	5.1	7.13	0.00	55.48	64	0.4	855.25	59.59	9.29	34.54	34.26	2.5	42.49	11.76	1.94	12.75
61-70	6.2	7.45	0.00	64.19	53	0.4	321.83	60.82	6.51	15.29	15.01	2.2	31.81	7.38	1.84	10.15
71-80	4.5	1.14	0.00	74.52	52	0.4	1781.35	73.06	9.30	23.11	22.99	1.5	29.76	11.82	0.47	4.95
81-90	15.4	0.48	0.00	86.47	120	0.5	350.33	35.16	3.24	9.32	9.26	2.5	15.82	7.99	0.94	5.47
91-100	5.9	0.23	0.00	94.97	46	0.2	165.02	29.60	2.61	4.04	4.02	0.3	4.29	7.76	0.25	0.00
All Units	**72.3**	**22.09**	**0.82**	**50.32**	**538**	**4.3**	**2,850.15**	**69.31**	**8.84**	**17.11**	**16.51**	**20.8**	**26.67**	**9.36**	**3.17**	**11.63**

Fossil Units — Table 6.2.2

External Causes Excluded, 2005 to 2009 Data







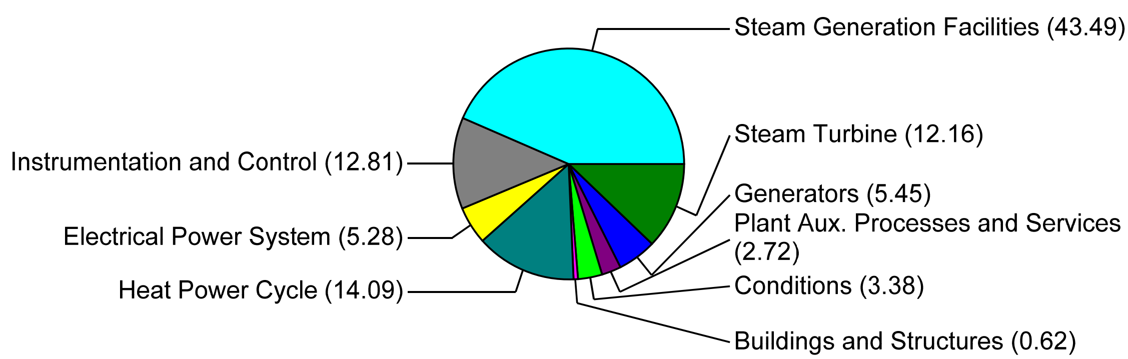
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	50.1	40.83	0.34	36.06	261	3.3	3688.95	112.01	13.58	21.04	20.10	11.9	22.61	9.83	3.44	8.40
100-199	144.7	23.57	3.94	58.49	951	4.8	2894.31	44.11	5.10	7.00	6.60	25.6	17.31	9.33	1.60	11.06
200-299	14.5	9.21	0.00	71.82	187	0.8	890.78	36.31	6.46	8.96	8.45	2.7	17.90	13.21	1.85	8.58
300-399	61.1	11.24	0.00	69.83	469	2.6	1774.03	47.64	4.76	9.67	9.52	10.9	16.55	8.52	0.31	7.28
400-599	114.2	16.46	0.00	58.99	1126	7.4	2978.43	57.91	9.05	14.23	13.79	29.0	24.28	10.63	4.76	9.10
Classification By Year Of Service																
6TH-10TH	1.0	0.00	0.00	92.08	3	0.0	37.16	14.63	0.53	1.25	1.25	0.1	6.93	2.13	0.00	5.75
11TH-15TH	18.6	0.06	0.00	88.41	123	0.4	263.00	29.63	2.36	3.59	2.88	2.1	10.84	6.23	0.67	6.68
16TH-20TH	16.7	0.12	0.00	89.69	121	0.5	451.75	36.66	3.11	6.06	5.49	1.9	10.85	7.29	0.87	3.85
21ST-25TH	40.7	3.88	0.27	75.22	388	2.1	2894.31	46.56	5.61	7.30	5.24	7.4	17.18	9.13	0.97	9.72
26TH-30TH	167.6	27.19	2.92	54.06	1238	7.1	2978.43	50.03	6.78	11.16	9.53	33.1	19.22	10.08	2.62	9.39
31ST-35TH	81.4	26.93	0.81	47.32	625	4.8	2850.15	67.77	9.94	14.82	12.2	21.1	24.61	10.97	3.51	11.74
36TH-40TH	26.4	11.27	0.00	69.66	318	1.1	880.58	31.19	4.94	8.53	7.62	4.1	14.30	12.81	1.29	6.03
41ST-45TH	8.1	41.90	0.00	30.18	42	1.0	3688.95	205.25	26.24	28.16	20.83	2.1	25.75	10.22	2.23	10.79
46TH-50TH	22.4	25.82	0.73	41.89	128	1.9	2148.48	127.86	13.86	21.95	15.56	7.3	30.44	8.64	6.30	11.15
51ST-55TH	1.7	15.89	0.00	61.40	8	0.0	89.65	15.72	0.91	35.40	34.49	1.0	49.86	5.13	3.43	2.85
Classification By Operating Factor																
0-10	60.3	76.18	0.29	6.24	151	2.5	3688.95	143.45	39.30	39.83	33.71	10.4	17.11	14.75	1.92	10.88
11-20	9.0	72.03	11.60	17.91	15	0.0	142.58	24.92	2.57	7.13	3.17	1.0	10.81	6.82	0.31	9.12
21-30	5.0	52.79	31.49	28.42	24	0.1	220.65	44.85	7.51	10.13	9.36	0.9	18.07	10.58	0.27	13.63
31-40	22.0	39.79	14.20	37.23	75	0.5	1630.08	56.68	5.43	8.79	6.98	5.2	23.40	6.99	2.78	16.95
41-50	44.0	24.20	0.00	45.61	345	2.8	2894.31	71.83	11.70	15.88	14.91	13.9	30.71	11.17	5.86	15.07
51-60	28.5	19.59	0.00	55.25	200	1.8	2978.43	79.65	10.01	14.31	14.06	7.7	26.66	8.28	4.80	12.39
61-70	63.4	4.57	0.00	65.70	696	4.6	1781.35	57.78	8.08	14.16	13.94	18.1	25.92	9.88	4.88	8.82
71-80	40.6	0.97	0.00	75.64	440	2.6	860.06	51.01	6.24	12.81	12.68	9.4	20.86	10.26	0.96	6.92
81-90	82.0	0.22	0.00	86.55	814	3.2	1774.03	34.71	4.10	6.82	6.72	11.2	13.28	10.18	0.54	6.00
91-100	29.8	0.07	0.00	92.65	234	0.7	451.75	27.93	2.59	3.36	3.31	2.2	7.34	7.89	0.53	3.51
All Units	**384.7**	**21.15**	**1.50**	**58.06**	**2994**	**18.9**	**3,688.95**	**55.28**	**7.10**	**11.15**	**10.76**	**80.1**	**19.98**	**9.77**	**2.58**	**9.41**

Fossil Units

Major Component Outage Code Report, 2005 to 2009

Table 6.2.3

Major Componenent Contribution to Fossil Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	94.00
Number of Unit Yars:	412.06
Overall Operating Factor:	61.51

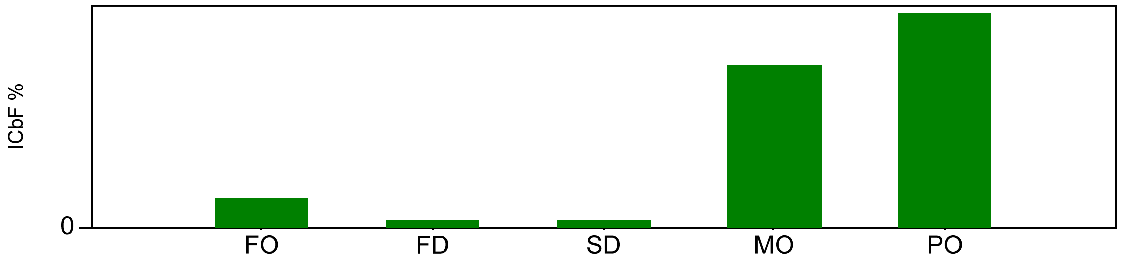
MAJOR COMPONENT	FORCED OUTAGES NO. OCC.	FORCED OUTAGES ICBF (%)	FORCED DERATINGS NO. OCC.	FORCED DERATINGS ICBF (%)	SCHEDULED DERATINGS NO. OCC.	SCHEDULED DERATINGS ICBF (%)	MAINTENANCE OUTAGES NO. OCC.	MAINTENANCE OUTAGES ICBF (%)	PLANNED OUTAGES NO. OCC.	PLANNED OUTAGES ICBF (%)	CONTRIBUTION TO UNIT ICBF (%)	CONTRIBUTION TO UNIT FOR (%)	CONTRIBUTION TO UNIT DAFOR (%)
Buildings and Structures	3	0.00	1	0.00	2	0.00	18	0.03	7	0.03	0.06	0.01	0.01
Conditions	90	0.82	10501	4.01	224	0.80	32	0.68	25	0.79	4.50	0.28	1.25
Electrical Power System	161	0.23	235	0.08	39	0.02	55	0.09	22	0.06	0.46	0.33	0.34
Generators	131	0.63	253	0.14	97	0.03	78	0.28	29	0.44	1.47	0.91	0.94
Heat Power Cycle	323	0.68	2885	2.10	213	0.53	280	0.83	14	0.69	3.19	0.40	1.00
Instrumentation and Control	505	0.37	1542	0.77	426	0.18	50	0.15	10	0.23	1.25	0.35	0.53
Plant Aux. Processes and Services	58	0.18	581	0.42	286	0.18	41	0.14	23	0.43	1.11	0.18	0.25
Steam Generation Facilities	1125	4.44	19761	11.40	2333	3.38	452	3.07	262	8.21	22.60	3.66	6.11
Steam Turbine	354	0.97	671	1.05	1102	0.80	109	0.75	78	2.12	4.88	1.16	1.26
TOTAL (External Causes Included)	2750	8.32	36430	19.97	4722	5.92	1115	6.02	470	13.00	39.52	7.28	11.69
TOTAL (External Causes Excluded)	2667	7.88	25935	16.72	4498	5.36	1086	5.65	446	12.78	36.52	7.51	11.16

Fossil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4

Building and Structure



Buildings and Structures ICbF by event type forFossil units based on 2005-2009 data.

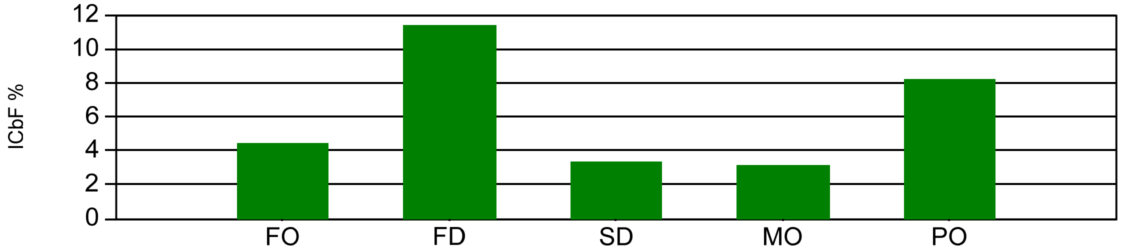
UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Buildings and Structures													
22000	Powerhouse	1	0.00	0	0.00	0	0.00	2	0.01	0	0.00	0.01	0.01
23290	Chimney	2	0.00	1	0.00	2	0.00	16	0.02	7	0.03	0.05	0.00
Buildings and Structures Total		**3**	**0.00**	**1**	**0.00**	**2**	**0.00**	**18**	**0.03**	**7**	**0.03**	**0.06**	**0.01**

Fossil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4
Steam Generators



Steam Generation Facilities ICbF by event type forFossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Steam Generation Facilities													
31000	Steam Generator/HRSG	168	0.61	1434	1.14	512	0.71	85	0.69	236	6.13	8.07	0.72
31120	Primary Air Fans - Pulverized Fuel	17	0.11	1051	0.81	51	0.12	12	0.13	0	0.09	0.90	0.15
31130	Primary Air Fan Drives - Pulverized Fuel	2	0.01	32	0.02	0	0.00	0	0.00	0	0.00	0.02	0.01
31150	Air Heaters	33	0.09	258	0.33	10	0.05	58	0.16	0	0.05	0.49	0.13
31170	Primary Air Duct - Pulverized Fuel	6	0.01	32	0.02	3	0.01	1	0.00	0	0.00	0.03	0.01
31210	Coal Feeders (Gravimetric Or Volumetric)	5	0.11	2615	0.56	150	0.14	2	0.11	0	0.11	0.59	0.16
31220	Pulverized Fuel Burner Piping And Valves	5	0.05	599	0.26	32	0.07	7	0.05	0	0.05	0.28	0.07
31230	Oil Burner Piping And Valves	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
31240	Gas Burner Piping And Valves	5	0.00	10	0.00	0	0.00	1	0.00	7	0.15	0.16	0.00
31250	Pulverizers	15	0.61	5315	3.12	1111	1.29	4	0.60	0	0.60	3.81	0.73
31262	Pulverizer Motors	0	0.01	55	0.05	5	0.01	0	0.01	0	0.01	0.05	0.01
31270	Burners And Windboxes	14	0.01	39	0.04	6	0.01	2	0.01	0	0.00	0.05	0.01
31280	Igniters	10	0.01	112	0.03	0	0.01	5	0.01	0	0.01	0.04	0.02
31300	Sootblower Systems	1	0.02	151	0.10	4	0.02	2	0.02	2	0.04	0.13	0.02
31510	Steam Drum - Scrubbers,Separators, Etc.	7	0.00	8	0.00	0	0.00	1	0.01	1	0.03	0.04	0.00
31530	Steam Generating Tubes (Between Steam Drum and Mud Drum)	16	0.05	14	0.02	0	0.00	5	0.02	0	0.00	0.08	0.07
31540	Waterwalls	272	0.79	137	0.07	1	0.01	48	0.11	3	0.03	0.98	1.18
31550	Circulating Pumps	6	0.01	60	0.05	10	0.01	1	0.01	1	0.01	0.06	0.02
31560	Circulating Pumps Drives	2	0.01	153	0.06	1	0.01	4	0.01	0	0.01	0.07	0.01
31570	Safety Valves	17	0.07	312	0.31	122	0.09	11	0.04	0	0.03	0.42	0.08
31580	Water Gauges	2	0.00	0	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
31701	Superheater/High Pressure Section	161	0.47	242	0.08	53	0.07	14	0.05	2	0.07	0.67	0.69
31702	Reheater	71	0.27	66	0.04	1	0.01	10	0.04	1	0.02	0.33	0.40
31703	Economizer/Low Pressure Section	53	0.14	20	0.00	0	0.00	3	0.00	0	0.00	0.15	0.21
31810	Attemperation	2	0.01	58	0.03	4	0.01	5	0.01	0	0.01	0.04	0.01
31820	Burner Tilt	0	0.00	10	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
31832	Flue Gas-Recirculation Fans	4	0.03	67	0.05	3	0.01	4	0.02	0	0.01	0.08	0.04
31833	Recirculation Fans Variable Speed	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
31834	Flue Gas Recirculation Motors	0	0.00	11	0.01	0	0.00	1	0.01	0	0.00	0.02	0.00
32100	Forced Draft Ducts	2	0.01	15	0.09	3	0.01	4	0.01	0	0.01	0.10	0.01
32310	Forced Draft Fans	28	0.11	198	0.35	18	0.10	10	0.09	0	0.09	0.39	0.16
32320	Forced Draft Fan Variable Speed Coupling	3	0.01	12	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
32330	Forced Draft Fan Motors	3	0.01	26	0.03	2	0.01	1	0.01	0	0.01	0.04	0.02
32400	Induced Draft Flues	1	0.00	1	0.00	1	0.00	10	0.02	1	0.00	0.02	0.00
32510	Induced Draft Fans	44	0.12	1064	0.75	37	0.11	28	0.14	0	0.08	0.87	0.17
32520	Induced Draft Fan Variable Speed Coupling Drives	3	0.01	1	0.00	1	0.00	4	0.01	0	0.00	0.02	0.01
32530	Induced Draft Fan Motors	3	0.01	141	0.06	2	0.01	1	0.01	0	0.01	0.07	0.02
33100	Main Steam Piping	18	0.06	11	0.01	1	0.00	14	0.03	1	0.02	0.11	0.09
33200	Hot Reheat Piping	4	0.01	4	0.00	0	0.00	0	0.00	0	0.00	0.02	0.02
33300	Cold Reheat Piping	3	0.01	2	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
33600	High Pressure Steam Piping	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00

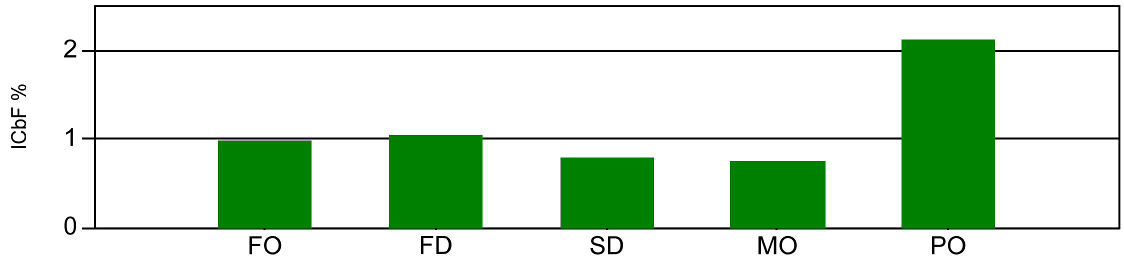
Fossil Units — Table 6.2.4

Detail Component Outage Code Report, 2005 to 2009 — Steam Generators

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Generation Facilities													
34100	Furnace And Water Gauge Television	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
34200	Boiler Blowdown System	2	0.00	27	0.01	0	0.00	1	0.00	0	0.00	0.01	0.00
34400	Boiler Drains System	3	0.00	1	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
34500	Boiler Boiling-Out, Alkaline Flushing	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
35110	Furnace Ash Removal System	39	0.15	904	0.46	19	0.13	12	0.13	1	0.12	0.52	0.23
35120	Pulverizer Pyrites Removal System	1	0.01	291	0.05	9	0.01	0	0.01	0	0.01	0.05	0.01
35130	Fly Ash Removal System - Dry Transportation	1	0.02	142	0.07	8	0.02	5	0.04	0	0.02	0.09	0.02
35140	Fly Ash Removal System - Wet	0	0.00	14	0.01	10	0.01	5	0.00	0	0.00	0.01	0.00
35210	Precipitators-Electrostatic	27	0.26	2780	1.90	36	0.21	54	0.32	2	0.24	2.13	0.39
35220	Precipitators-Mechanical	1	0.00	4	0.00	0	0.00	1	0.00	1	0.04	0.04	0.00
35230	Precipitators-Baghouse	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
36100	Coal Receiving Systems	1	0.01	70	0.02	8	0.01	1	0.01	0	0.01	0.03	0.01
36200	Coal Storage Systems	1	0.03	647	0.13	35	0.03	1	0.03	1	0.03	0.13	0.04
36300	Coal Handling Systems	24	0.09	393	0.18	34	0.06	2	0.05	0	0.05	0.24	0.13
36370	Coal Stacker/Reclaimer Machine	1	0.00	6	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
36400	Coal Processing Systems	0	0.00	23	0.01	2	0.00	0	0.00	0	0.00	0.01	0.00
37100	Fuel Oil Receiving Systems	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37300	Fuel Oil Transfer Systems	0	0.00	0	0.00	6	0.00	0	0.00	2	0.01	0.01	0.00
37400	Fuel Oil Forwarding Systems	2	0.00	4	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37500	Fuel Oil Boosting Systems	2	0.00	4	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
37600	Fuel Oil Heating Systems	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
38000	Sulphur Oxides Removal System	11	0.01	37	0.02	20	0.00	6	0.04	0	0.00	0.06	0.01
38300	IN-FURNACE BED LIMESTONE INJECTION SYS	0	0.00	1	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
38400	FLUID BED LIMESTONE INJECTION SYSTEM	0	0.00	62	0.03	0	0.00	0	0.00	0	0.00	0.03	0.00
Steam Generation Facilities Total		**1125**	**4.44**	**19761**	**11.40**	**2333**	**3.38**	**452**	**3.07**	**262**	**8.21**	**22.60**	**6.11**

Fossil Units — Table 6.2.4

Detail Component Outage Code Report, 2005 to 2009 — Steam Turbine



Steam Turbine ICbF by event type forFossil units based on 2005-2009 data.

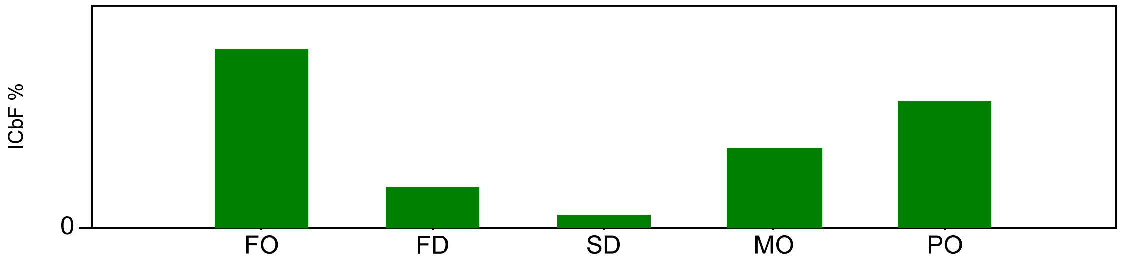
UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Steam Turbine													
41100	Turbine	140	0.57	357	0.77	223	0.28	45	0.41	65	1.60	3.39	0.81
41110	Cylinders	5	0.03	7	0.00	0	0.00	0	0.00	0	0.00	0.03	0.04
41120	Rotors	5	0.00	4	0.00	0	0.00	2	0.00	1	0.07	0.07	0.00
41121	Shaft Coupling Mechanism	2	0.00	0	0.00	0	0.00	4	0.03	7	0.21	0.24	0.00
41130	Blades	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
41140	Crossover Piping	3	0.00	6	0.00	0	0.00	1	0.01	1	0.03	0.04	0.01
41150	Turning Gear	4	0.01	0	0.00	0	0.00	1	0.01	0	0.00	0.02	0.01
41157	Turning Gear Motor	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41160	Valve Gear	41	0.07	87	0.06	53	0.02	22	0.10	0	0.02	0.20	0.10
41170	Bearings And Pedestals	29	0.02	61	0.03	1	0.01	4	0.03	1	0.04	0.10	0.03
41200	Lubricating Oil System	28	0.02	7	0.01	0	0.00	7	0.02	0	0.00	0.04	0.03
41500	Gland Seal System-Steam	11	0.03	2	0.00	1	0.00	7	0.01	2	0.04	0.07	0.05
41540	Gland Seal System-Water	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41600	Turbovisory	35	0.06	25	0.01	6	0.00	3	0.00	0	0.00	0.07	0.09
41700	Governing System	49	0.16	114	0.17	818	0.49	12	0.13	1	0.11	0.61	0.09
Steam Turbine Total		**354**	**0.97**	**671**	**1.05**	**1102**	**0.80**	**109**	**0.75**	**78**	**2.12**	**4.88**	**1.26**

Fossil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4
Generators



Generators ICbF by event type forFossil units based on 2005-2009 data.

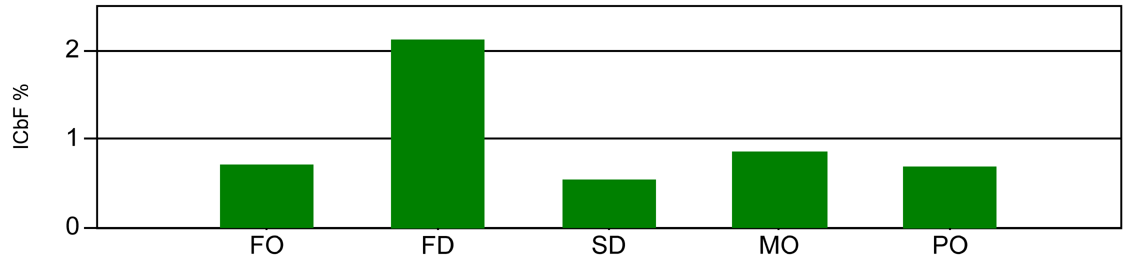
UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Generators													
42100	Generator	22	0.09	35	0.02	27	0.01	6	0.01	11	0.13	0.24	0.13
42110	Generator Rotor	10	0.09	2	0.00	15	0.00	1	0.03	7	0.24	0.37	0.14
42111	Generator Bearings	10	0.12	44	0.01	0	0.00	3	0.02	0	0.00	0.15	0.18
42112	Generator Hydrogen Seals	10	0.05	3	0.00	0	0.00	5	0.02	1	0.02	0.09	0.07
42114	Generator Collector And Brushes	2	0.00	5	0.01	2	0.00	23	0.04	0	0.00	0.05	0.00
42120	Generator Stator	4	0.06	16	0.01	1	0.00	0	0.00	1	0.03	0.10	0.08
42200	Excitation Systems Equipment	43	0.02	21	0.01	28	0.00	22	0.05	8	0.00	0.09	0.03
42300	Hydrogen Gas Cooling System	19	0.05	82	0.06	22	0.02	7	0.08	1	0.02	0.17	0.08
42400	Generator Liquid Cooling System	8	0.15	41	0.02	2	0.00	6	0.02	0	0.00	0.19	0.23
42500	Seal Oil System	3	0.00	4	0.00	0	0.00	5	0.01	0	0.00	0.02	0.00
Generators Total		**131**	**0.63**	**253**	**0.14**	**97**	**0.03**	**78**	**0.28**	**29**	**0.44**	**1.47**	**0.94**

Fossil Units — Table 6.2.4

Detail Component Outage Code Report, 2005 to 2009 — Heat Power Cycle



Heat Power Cycle ICbF by event type forFossil units based on 2005-2009 data.

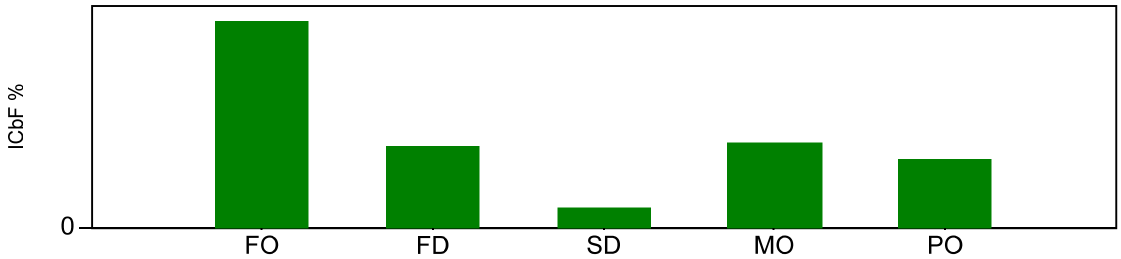
UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Heat Power Cycle													
43090	Boiler Feedwater Piping And Supports	28	0.03	25	0.01	0	0.00	15	0.03	0	0.00	0.06	0.05
43100	High Pressure Feedwater Heaters And	37	0.07	359	0.33	10	0.05	32	0.09	4	0.10	0.48	0.11
43200	Boiler Feed Pumps And Auxiliaries	67	0.15	761	0.37	34	0.12	38	0.16	0	0.11	0.48	0.22
43260	Boiler Feed Pump Variable Speed Coupling	5	0.01	30	0.02	3	0.01	2	0.01	0	0.01	0.03	0.01
43300	Boiler Feed Pump Turbines & Auxiliaries	14	0.05	175	0.13	17	0.04	8	0.05	0	0.04	0.16	0.07
43400	Boiler Feed Pump Motors And Auxiliaries	12	0.08	74	0.18	8	0.11	2	0.08	1	0.08	0.24	0.10
44090	Condensate Piping And Supports	7	0.01	21	0.01	1	0.00	2	0.00	0	0.00	0.02	0.01
44110	Condensor	22	0.04	316	0.26	12	0.03	28	0.07	6	0.15	0.46	0.06
44120	Condensor Tubes	40	0.14	658	0.42	92	0.10	116	0.22	1	0.11	0.70	0.20
44200	Condensate Extraction Pumps And	12	0.05	220	0.20	22	0.05	7	0.05	0	0.04	0.22	0.08
44300	Condensate Extraction Pump Motors And	1	0.00	28	0.03	2	0.01	0	0.00	0	0.00	0.03	0.01
44400	Low Pressure Feedwater Heaters And	7	0.01	57	0.07	2	0.01	1	0.01	0	0.01	0.08	0.01
44500	Deaerator, Storage Tank, And Auxiliaries	24	0.02	36	0.01	2	0.00	14	0.03	2	0.04	0.10	0.04
45000	Air Extraction System	13	0.01	21	0.01	0	0.00	2	0.01	0	0.00	0.03	0.01
45090	Air Extraction System And Piping Support	1	0.00	4	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
45100	Air Extraction System Vacuum Pumps	10	0.00	20	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
45200	Air Extraction System Vacuum Pump, Motor and Auxiliaries	4	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
45300	Steam Air Ejectors	5	0.00	5	0.00	0	0.00	1	0.00	0	0.00	0.01	0.01
46100	Turbine Bypass System	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
47000	Condensate Make-up System	4	0.00	5	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48000	Feed Cycle Auxiliary Systems	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48100	Extraction Steam System	2	0.01	13	0.01	1	0.00	2	0.00	0	0.00	0.02	0.01
48200	Feedwater Heater Drains System	4	0.00	21	0.02	2	0.00	4	0.00	0	0.00	0.03	0.00
48400	Feedwater Heater Relief Valve, Vent	1	0.00	35	0.02	4	0.00	2	0.00	0	0.00	0.02	0.00
48500	Turbine And Piping Drains	2	0.00	0	0.00	0	0.00	3	0.02	0	0.00	0.02	0.00
Heat Power Cycle Total		**323**	**0.68**	**2885**	**2.10**	**213**	**0.53**	**280**	**0.83**	**14**	**0.69**	**3.19**	**1.00**

Fossil Units — Table 6.2.4

Detail Component Outage Code Report, 2005 to 2009 — Electrical Power Sys.



Electrical Power System ICbF by event type forFossil units based on 2005-2009 data.

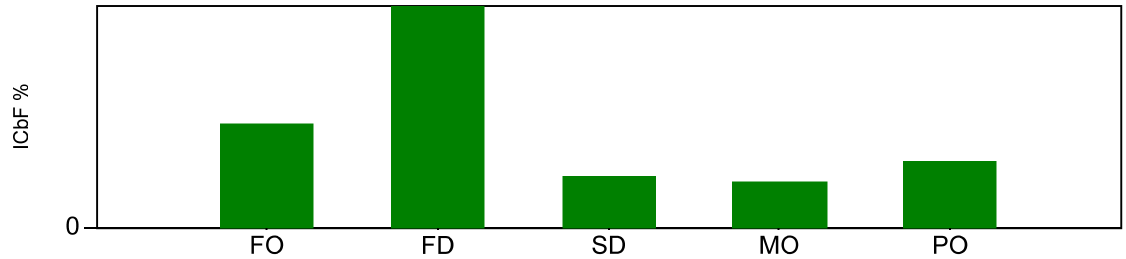
UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Electrical Power System													
51100	Output System Generator Voltage Equipment	12	0.01	8	0.00	17	0.00	0	0.00	4	0.00	0.01	0.01
51120	Generator Power Transformers	38	0.07	59	0.03	5	0.01	9	0.01	7	0.01	0.11	0.10
51130	Switching Equipment-Generator Voltage	2	0.00	1	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51133	Circuit Breakers-Generator Voltage	6	0.00	3	0.00	0	0.00	1	0.00	3	0.00	0.00	0.00
51136	Disconnect Switches-Generator Voltage	4	0.00	1	0.00	0	0.00	1	0.00	1	0.00	0.00	0.00
51150	Bus Duct, Bus, Cable	2	0.00	0	0.00	0	0.00	2	0.00	2	0.01	0.02	0.00
51151	Bus Duct Cooling System	0	0.00	4	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51170	Generator Neutral Grounding Equipment	7	0.00	5	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
52100	Generator Voltage Supply System	7	0.05	7	0.00	2	0.00	0	0.00	1	0.01	0.07	0.08
52120	Station Service Transformer	8	0.01	15	0.01	8	0.00	0	0.00	0	0.00	0.02	0.01
52130	Unit Service Transformer	10	0.01	36	0.01	1	0.00	10	0.02	0	0.00	0.03	0.01
52140	Exciter XFMR	3	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
53200	Station Service Power Distribution	52	0.08	91	0.03	6	0.01	21	0.05	2	0.02	0.17	0.11
55000	Direct Current Power Supplies	10	0.00	4	0.00	0	0.00	9	0.01	2	0.01	0.02	0.01
Electrical Power System Total		**161**	**0.23**	**235**	**0.08**	**39**	**0.02**	**55**	**0.09**	**22**	**0.06**	**0.46**	**0.34**

Fossil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4
Ins. and Control



Instrumentation and Control ICbF by event type forFossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

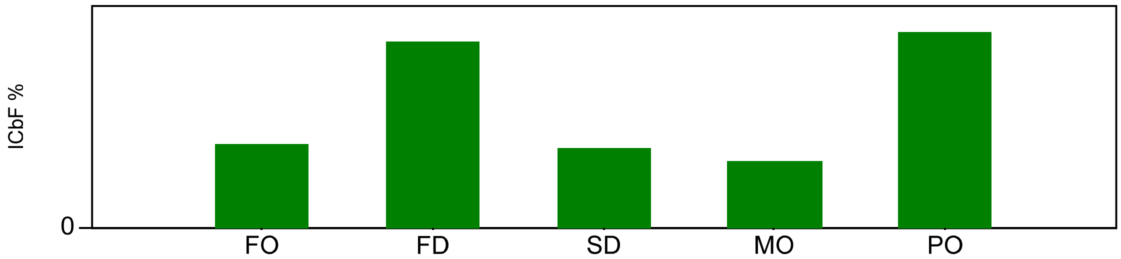
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Instrumentation and Control													
63100	Steam Generator Controls	125	0.07	817	0.36	341	0.08	13	0.05	0	0.04	0.44	0.09
63200	Equipment Controls-Furnace Draft	10	0.02	171	0.14	4	0.02	0	0.02	0	0.02	0.14	0.03
63300	Primary Steam Instrumentation & Control	6	0.00	19	0.00	7	0.00	0	0.00	0	0.00	0.01	0.00
63400	Auxiliary Systems -Instrumentation and Control	5	0.00	9	0.01	3	0.00	2	0.00	0	0.00	0.01	0.00
63500	Waste Removal Systems - Instrumentation and Control	0	0.00	6	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
63600	Fuel Coal Management - Instrumentation and Control	15	0.01	133	0.04	1	0.01	1	0.01	0	0.01	0.04	0.01
63700	Fuel Oil Management - Instrumentation	2	0.00	4	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
63800	Sulphur Oxide Removal System - Instrumentation and Control	0	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
63900	Ignition Fuel,Fuel Gas, & Miscellaneous	24	0.01	18	0.00	1	0.00	0	0.00	1	0.00	0.02	0.02
64100	Steam Turbine And Auxiliaries -	58	0.02	51	0.04	14	0.01	17	0.01	0	0.01	0.06	0.03
64200	Generator And Auxiliaries - Instrumentation and Control	40	0.06	59	0.06	12	0.03	5	0.04	2	0.10	0.18	0.08
64210	Supervisory Control & Data Acquisition	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64300	Boiler Feedwater System -Instrumentation and Control	68	0.03	97	0.04	4	0.01	2	0.01	0	0.01	0.07	0.04
64400	Condensate System - Instrumentation and Control	10	0.01	21	0.01	1	0.00	0	0.00	0	0.00	0.02	0.02
64500	Condensate Air Extraction System - Instrumentation and Control	5	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64700	Condensate Make-up system - Instrumentation and Control	1	0.00	7	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64800	Feedwater Heating Anciliary Systems - Instrumentation and Control	4	0.01	29	0.03	0	0.00	0	0.00	0	0.00	0.03	0.01
65100	Main Power Output Systems - Control and Protection	22	0.01	12	0.00	2	0.00	4	0.00	3	0.00	0.01	0.01
65200	Station Service Main Transformation - Control and Protection	7	0.00	5	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
65300	Alternating Current Power Distribution - Control and Protection	14	0.00	15	0.00	1	0.00	1	0.00	0	0.00	0.01	0.01
65500	Direct Current Power Distribution - Control and Protection	16	0.01	1	0.00	0	0.00	1	0.00	0	0.00	0.01	0.01
65900	System Control Facilities	1	0.00	2	0.00	2	0.00	0	0.00	0	0.00	0.00	0.00
67000	Plant Auxiliary Processes And Services - Instrumentation and Control	9	0.01	38	0.02	16	0.01	0	0.00	0	0.00	0.03	0.01
69000	Computers	62	0.10	27	0.01	16	0.01	4	0.01	4	0.04	0.15	0.15
Instrumentation and Control Total		**505**	**0.37**	**1542**	**0.77**	**426**	**0.18**	**50**	**0.15**	**10**	**0.23**	**1.25**	**0.53**

Fossil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4

Auxiliary Processes



Plant Aux. Processes and Services ICbF by event type forFossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

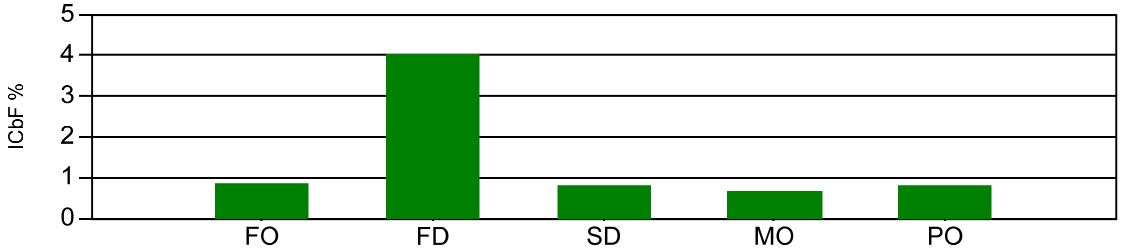
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Plant Aux. Processes and Services													
71000	Circulating Water Systems	8	0.02	70	0.03	11	0.01	12	0.02	11	0.12	0.19	0.03
71110	Travelling Water Screens	5	0.01	70	0.03	2	0.01	2	0.01	0	0.01	0.04	0.01
71120	Circulating Water Pumps	6	0.03	62	0.04	3	0.01	1	0.01	0	0.01	0.06	0.05
71127	Circulating Water Pump Motors	1	0.01	21	0.09	1	0.01	0	0.01	0	0.01	0.09	0.02
71140	Circulating Water Main Butterfly Valves and Operators	3	0.00	13	0.00	1	0.00	3	0.01	0	0.00	0.01	0.01
71190	Circulating Water Piping And Supports	1	0.00	14	0.01	2	0.00	5	0.01	2	0.00	0.02	0.00
71500	Circulating Water Screenwash System	0	0.00	4	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
71700	Circulating Water Cooling Towers	0	0.01	154	0.11	0	0.01	1	0.01	0	0.01	0.11	0.01
71800	Circulating Water Cooling Ponds	0	0.00	97	0.04	0	0.00	0	0.00	0	0.00	0.04	0.00
72000	Service Water Systems	3	0.03	8	0.00	1	0.00	4	0.01	2	0.05	0.09	0.04
72100	Service Water Low Pressure Open System	5	0.00	3	0.00	0	0.00	3	0.01	1	0.02	0.03	0.00
72800	Ash Transport Water Systems	1	0.04	15	0.04	0	0.01	0	0.01	0	0.01	0.06	0.05
73000	Heating, Ventilating, And Air	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
73100	Auxiliary Steam And Condensate Systems	5	0.00	10	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
73200	Powerhouse Heating & Ventilating Systems	2	0.01	4	0.01	261	0.12	2	0.01	0	0.00	0.13	0.00
74000	Water Treatment Plant	11	0.02	18	0.01	0	0.00	2	0.00	5	0.11	0.14	0.03
75000	Compressed Air Systems	1	0.00	0	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
75110	Service Air System	1	0.00	1	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
75120	Instrument Air System	4	0.00	9	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
76000	Miscellaneous Services	1	0.00	0	0.00	2	0.00	0	0.02	2	0.08	0.09	0.00
78000	Fire Protection Systems	0	0.00	7	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
Plant Aux. Processes and Services Total		**58**	**0.18**	**581**	**0.42**	**286**	**0.18**	**41**	**0.14**	**23**	**0.43**	**1.11**	**0.25**

Fossil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.4

Conditions



Conditions ICbF by event type forFossil units based on 2005-2009 data.

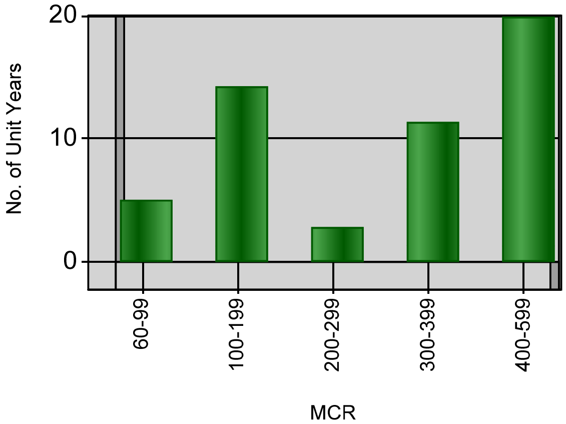
UNIT STATISTICS

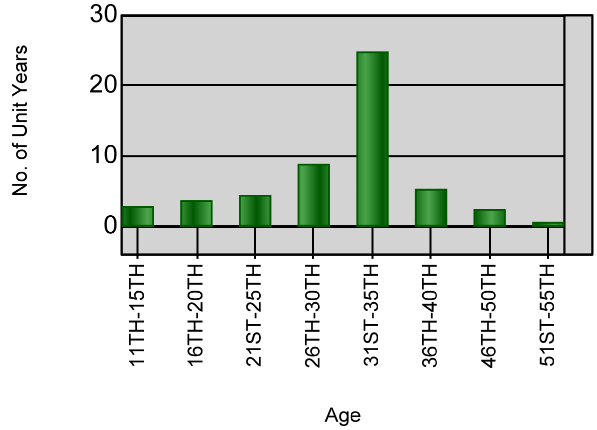
Number of Units:	94.00
Number of Unit Years:	412.06
Overall Operating Factor:	61.51

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
00500	Regulatory Bodies	0	0.00	2	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
01410	Poor Quality Fuel, Heat Content	8	0.34	3395	1.79	130	0.47	1	0.34	0	0.34	1.92	0.50
01420	Problems - Primary Fuel for Units with Secondary Fuel Op.	1	0.02	275	0.13	5	0.02	0	0.02	0	0.02	0.13	0.03
04200	Synchronous Condenser Operation	1	0.00	0	0.00	0	0.00	0	0.00	1	0.00	0.00	0.00
05200	Transmission Limitations	26	0.09	144	0.22	60	0.08	21	0.08	16	0.09	0.28	0.14
05201	Powerhouse Substation	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
05202	Transmission Line	3	0.00	3	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
07010	Site Environment, Storms, Floods	9	0.04	39	0.04	10	0.01	1	0.01	0	0.01	0.09	0.07
07110	Nitrous Oxides - Environmental Restriction	0	0.00	5	0.00	3	0.00	0	0.00	0	0.00	0.00	0.00
07120	Sulphur Dioxide - Environmental	4	0.02	698	0.10	2	0.02	1	0.02	0	0.02	0.10	0.03
07130	Particulates - Environmental Restriction	6	0.14	5662	1.51	3	0.14	0	0.14	0	0.14	1.51	0.22
07210	Cooling Water Discharge - Thermal Effects	4	0.06	213	0.19	4	0.05	0	0.05	0	0.05	0.20	0.09
07220	Liquid And Chemical Effluents	0	0.00	0	0.00	0	0.00	1	0.00	1	0.00	0.00	0.00
07230	Solid Waste Effluents	0	0.00	3	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
08160	Fire, General	6	0.05	12	0.00	0	0.00	0	0.00	0	0.00	0.05	0.08
08910	Staff Shortage	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.02
08940	Labour Troubles	1	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
99999	Other	18	0.05	50	0.03	6	0.01	6	0.02	7	0.12	0.21	0.07
Conditions Total		**90**	**0.82**	**10501**	**4.01**	**224**	**0.80**	**32**	**0.68**	**25**	**0.79**	**4.50**	**1.25**

Fossil - Coal Units
External Causes Excluded, 2007 Data

Table 6.2.5



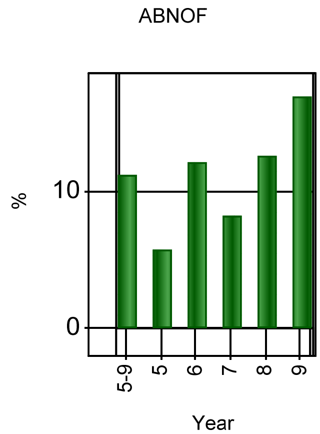


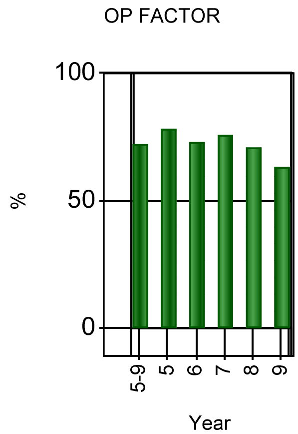
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	5.1	24.84	0.00	35.96	55	0.8	2148.48	123.22	21.44	50.49	48.94	2.5	41.44	14.82	0.52	10.20
100-199	14.3	7.57	0.00	73.76	103	0.3	283.45	28.93	2.81	6.78	6.70	2.6	17.06	7.98	1.95	9.56
200-299	2.8	18.93	0.00	62.63	29	0.2	321.83	45.79	6.95	10.10	9.91	0.5	15.74	11.82	0.72	7.61
300-399	11.4	15.79	0.00	59.92	95	0.5	422.25	49.52	5.43	20.48	20.37	3.5	26.71	9.42	0.03	7.91
400-599	19.9	17.25	0.00	49.75	203	1.6	2850.15	70.43	11.55	16.52	15.74	6.0	27.17	10.09	7.51	8.17
Classification By Year Of Service																
11TH-15TH	2.9	0.00	0.00	90.91	15	0.1	165.02	36.18	2.15	4.41	4.4	0.2	8.26	4.26	0.15	3.86
16TH-20TH	3.7	0.00	0.00	85.50	37	0.1	132.10	26.67	2.96	13.27	13.2	0.7	18.67	10.02	3.09	1.75
21ST-25TH	4.5	11.99	0.00	67.17	30	0.1	188.95	38.30	3.31	5.41	5.35	0.6	12.89	6.13	0.28	8.28
26TH-30TH	8.9	11.00	0.00	62.21	74	0.3	321.83	37.99	4.23	16.33	16.2	2.7	27.09	8.67	2.34	10.52
31ST-35TH	24.9	21.75	0.00	47.79	241	2.0	2850.15	71.86	12.01	18.09	17.42	7.4	27.39	11.27	5.92	9.00
36TH-40TH	5.4	12.05	0.00	66.48	57	0.1	161.23	21.71	3.02	10.55	10.48	1.0	16.87	12.13	0.11	8.47
46TH-50TH	2.5	24.70	0.00	20.32	25	0.7	2148.48	236.93	41.96	70.02	65.32	1.6	53.92	14.97	0.76	15.04
51ST-55TH	0.7	0.00	0.00	60.90	6	0.0	89.65	19.52	1.42	57.00	56.99	0.6	59.53	6.48	0.09	5.79
Classification By Operating Factor																
0-10	2.8	47.56	0.00	5.66	20	0.6	2148.48	279.38	78.45	78.45	70.65	1.2	40.84	29.45	7.61	11.95
11-20	5.7	57.32	0.00	14.59	41	0.1	622.53	32.04	13.54	22.82	19.14	1.5	24.76	21.06	5.82	14.21
21-30	3.8	30.75	0.00	26.00	31	0.6	2850.15	174.24	35.44	38.35	37.63	1.6	39.00	13.46	11.07	10.54
31-40	5.3	19.05	0.00	35.51	54	0.4	1026.72	64.10	12.80	17.69	17.06	2.2	35.11	14.87	6.52	18.85
41-50	3.9	12.12	0.00	43.78	32	0.2	176.63	50.54	5.42	12.94	12.36	1.4	28.55	5.58	5.12	13.31
51-60	3.1	3.16	0.00	56.28	52	0.3	375.53	50.31	8.60	41.22	41.02	1.9	46.79	13.24	2.75	7.18
61-70	4.2	3.11	0.00	65.12	49	0.4	321.83	63.39	8.09	18.83	18.65	1.5	29.66	8.69	1.06	7.96
71-80	3.5	1.06	0.00	74.94	46	0.2	329.18	41.94	5.92	23.21	23.1	1.2	30.77	12.56	0.21	5.49
81-90	14.4	0.51	0.00	86.81	114	0.4	283.45	32.38	3.01	9.32	9.27	2.3	15.40	8.10	1.00	5.01
91-100	5.9	0.23	0.00	94.97	46	0.2	165.02	29.60	2.61	4.04	4.02	0.3	4.29	7.76	0.25	0.00
All Units	**53.5**	**15.33**	**0.00**	**57.33**	**485**	**3.4**	**2,850.15**	**62.03**	**8.19**	**17.22**	**16.83**	**15.0**	**25.37**	**9.72**	**3.41**	**8.64**

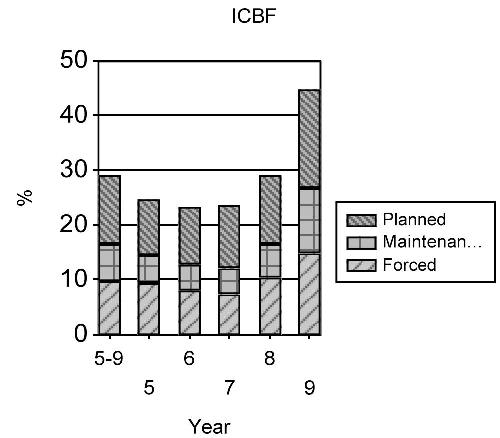
Fossil - Coal Units

Table 6.2.6

External Causes Excluded, 2005 to 2009 Data





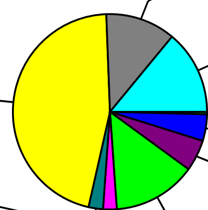


	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	26.1	28.80	0.62	42.99	227	2.7	3688.95	102.90	15.48	24.77	23.53	7.1	24.91	12.35	0.39	9.49
100-199	77.0	6.22	0.00	78.82	733	2.8	2894.31	33.99	4.21	5.80	5.65	10.7	13.50	10.03	1.12	7.27
200-299	14.5	9.21	0.00	71.82	187	0.8	890.78	36.31	6.46	8.96	8.45	2.7	17.90	13.21	1.85	8.58
300-399	61.1	11.24	0.00	69.83	469	2.6	1774.03	47.64	4.76	9.67	9.52	10.9	16.55	8.52	0.31	7.28
400-599	99.3	8.74	0.00	66.01	1071	7.2	2978.43	59.27	9.00	14.26	13.86	26.1	25.00	10.59	5.00	8.31
Classification By Year Of Service																
6TH-10TH	1.0	0.00	0.00	92.08	3	0.0	37.16	14.63	0.53	1.25	1.25	0.1	6.93	2.13	0.00	5.75
11TH-15TH	18.6	0.06	0.00	88.41	123	0.4	263.00	29.63	2.36	3.59	2.88	2.1	10.84	6.23	0.67	6.68
16TH-20TH	16.7	0.12	0.00	89.69	121	0.5	451.75	36.66	3.11	6.06	5.49	1.9	10.85	7.29	0.87	3.85
21ST-25TH	39.9	3.58	0.00	75.86	380	2.0	2894.31	47.19	5.66	7.26	5.2	7.1	16.96	9.09	0.95	9.52
26TH-30TH	108.4	12.02	0.00	68.13	1050	5.9	2978.43	48.83	6.78	11.61	9.76	23.1	20.52	10.42	2.99	8.01
31ST-35TH	51.9	14.54	0.00	58.85	547	3.9	2850.15	62.90	9.79	15.02	12.4	13.7	24.49	11.81	4.33	8.09
36TH-40TH	23.4	7.48	0.00	72.54	316	1.1	880.58	31.34	5.24	9.05	8.1	3.8	14.66	13.56	0.70	6.16
41ST-45TH	4.1	47.60	0.00	19.58	28	0.7	3688.95	214.74	38.45	41.87	28.32	1.2	28.43	15.87	0.78	10.25
46TH-50TH	13.4	26.42	1.17	41.10	113	1.5	2148.48	116.11	16.24	25.88	16.77	4.1	27.36	11.30	0.28	11.03
51ST-55TH	0.7	0.00	0.00	60.90	6	0.0	89.65	19.52	1.42	57.00	56.38	0.6	59.53	6.48	0.09	5.79
Classification By Operating Factor																
0-10	14.7	61.71	1.18	5.60	72	1.9	3688.95	226.18	67.28	67.41	60.59	4.6	30.95	24.92	2.28	16.22
11-20	4.0	72.35	0.00	20.91	11	0.0	141.53	19.63	2.86	4.10	4.05	0.3	7.03	10.75	0.09	6.03
21-30	0.3	16.92	0.00	24.01	21	0.1	220.65	48.12	47.95	62.18	60.9	0.2	52.47	104.00	3.84	0.00
31-40	6.6	50.48	0.00	38.26	39	0.2	342.98	46.01	7.31	11.61	9.82	0.8	12.03	11.93	0.76	6.29
41-50	19.2	26.42	0.00	44.29	247	1.5	2894.31	52.05	13.38	17.37	15.74	5.3	26.18	16.81	4.10	12.16
51-60	23.5	18.10	0.00	54.88	190	1.8	2978.43	82.74	11.74	16.83	16.54	6.9	28.81	9.31	5.19	12.28
61-70	58.5	3.75	0.00	65.72	673	4.3	1270.65	55.59	8.05	14.52	14.28	17.3	26.60	10.18	4.95	9.01
71-80	40.6	0.97	0.00	75.64	440	2.6	860.06	51.01	6.24	12.81	12.68	9.4	20.86	10.26	0.96	6.92
81-90	78.1	0.23	0.00	86.62	760	3.0	1774.03	35.02	4.04	6.82	6.73	10.6	13.14	9.93	0.52	5.88
91-100	29.8	0.07	0.00	92.65	234	0.7	451.75	27.93	2.59	3.36	3.31	2.2	7.34	7.89	0.53	3.51
All Units	278.0	10.61	0.06	68.38	2687	16.1	3,688.95	52.43	6.96	11.23	10.93	57.6	19.62	10.18	2.29	7.93

Fossil - Coal Units
Major Component Outage Code Report, 2005 to 2009

Table 6.2.7

Major Componenent Contribution to Coal-Fired Fossil Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	64.00
Number of Unit Yars:	296.68
Overall Operating Factor:	73.04

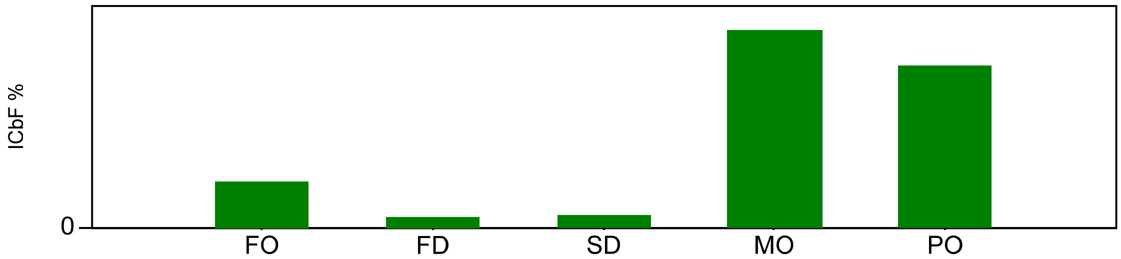
MAJOR COMPONENT	FORCED OUTAGES NO. OCC.	FORCED OUTAGES ICBF (%)	FORCED DERATINGS NO. OCC.	FORCED DERATINGS ICBF (%)	SCHEDULED DERATINGS NO. OCC.	SCHEDULED DERATINGS ICBF (%)	MAINTENANCE OUTAGES NO. OCC.	MAINTENANCE OUTAGES ICBF (%)	PLANNED OUTAGES NO. OCC.	PLANNED OUTAGES ICBF (%)	CONTRIBUTION TO UNIT ICBF (%)	CONTRIBUTION TO UNIT FOR (%)	CONTRIBUTION TO UNIT DAFOR (%)
Buildings and Structures	3	0.00	1	0.00	2	0.00	9	0.03	4	0.02	0.05	0.01	0.01
Conditions	71	1.00	10482	5.43	211	1.07	6	0.89	8	1.02	5.93	0.16	1.25
Electrical Power System	142	0.22	231	0.11	39	0.02	37	0.11	14	0.08	0.47	0.24	0.27
Generators	109	0.63	245	0.19	72	0.04	38	0.18	12	0.27	1.18	0.72	0.78
Heat Power Cycle	285	0.79	2796	2.64	194	0.58	216	0.84	6	0.61	3.51	0.39	1.00
Instrumentation and Control	448	0.46	1491	1.05	416	0.23	41	0.20	9	0.33	1.62	0.41	0.56
Plant Aux. Processes and Services	52	0.22	554	0.44	283	0.22	19	0.10	10	0.40	1.17	0.20	0.28
Steam Generation Facilities	1039	5.26	19401	14.10	2194	3.79	359	3.51	184	8.22	25.85	3.79	6.32
Steam Turbine	303	1.11	634	1.38	1066	0.84	78	0.57	43	1.26	4.22	1.12	1.21
TOTAL (External Causes Included)	2452	9.69	35835	25.34	4477	6.79	803	6.43	290	12.21	44.00	7.04	11.68
TOTAL (External Causes Excluded)	2386	9.31	25363	21.08	4266	6.10	798	5.94	282	11.89	40.23	7.42	11.22

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Buildings and Structure



Buildings and Structures ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

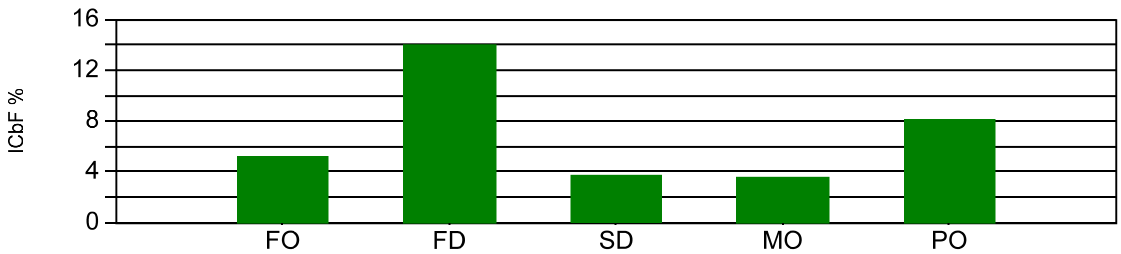
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Buildings and Structures													
22000	Powerhouse	1	0.00	0	0.00	0	0.00	2	0.01	0	0.00	0.01	0.01
23290	Chimney	2	0.00	1	0.00	2	0.00	7	0.02	4	0.02	0.04	0.00
Buildings and Structures Total		**3**	**0.00**	**1**	**0.00**	**2**	**0.00**	**9**	**0.03**	**4**	**0.02**	**0.05**	**0.01**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Steam Generation



Steam Generation Facilities ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Generation Facilities													
31000	Steam Generator/HRSG	149	0.56	1283	0.86	414	0.35	67	0.63	171	5.92	7.67	0.68
31120	Primary Air Fans - Pulverized Fuel	17	0.15	1051	1.11	51	0.16	12	0.17	0	0.12	1.23	0.18
31130	Primary Air Fan Drives - Pulverized Fuel	2	0.01	32	0.03	0	0.01	0	0.01	0	0.01	0.03	0.01
31150	Air Heaters	31	0.10	227	0.28	10	0.05	34	0.16	0	0.05	0.46	0.13
31170	Primary Air Duct - Pulverized Fuel	6	0.01	32	0.03	3	0.01	1	0.01	0	0.00	0.04	0.01
31210	Coal Feeders (Gravimetric Or Volumetric)	5	0.15	2615	0.76	150	0.19	2	0.16	0	0.15	0.81	0.18
31220	Pulverized Fuel Burner Piping And Valves	5	0.07	592	0.35	32	0.09	7	0.07	0	0.07	0.38	0.08
31230	Oil Burner Piping And Valves	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
31240	Gas Burner Piping And Valves	5	0.00	9	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
31250	Pulverizers	15	0.83	5315	4.26	1111	1.77	4	0.83	0	0.82	5.20	0.84
31262	Pulverizer Motors	0	0.01	55	0.06	5	0.02	0	0.01	0	0.01	0.07	0.01
31270	Burners And Windboxes	10	0.01	35	0.04	5	0.00	2	0.01	0	0.00	0.06	0.01
31280	Igniters	8	0.01	108	0.04	0	0.01	5	0.01	0	0.01	0.05	0.02
31300	Sootblower Systems	1	0.02	149	0.14	4	0.02	0	0.02	2	0.05	0.17	0.03
31510	Steam Drum - Scrubbers,Separators, Etc.	7	0.00	8	0.01	0	0.00	0	0.00	1	0.04	0.05	0.00
31530	Steam Generating Tubes (Between Steam Drum and Mud Drum)	14	0.05	13	0.01	0	0.00	1	0.00	0	0.00	0.06	0.07
31540	Waterwalls	264	1.03	137	0.09	1	0.01	33	0.09	3	0.05	1.24	1.31
31550	Circulating Pumps	6	0.01	49	0.05	10	0.01	1	0.01	1	0.01	0.06	0.01
31560	Circulating Pumps Drives	2	0.01	153	0.08	1	0.01	4	0.02	0	0.01	0.10	0.01
31570	Safety Valves	15	0.05	304	0.36	98	0.08	9	0.04	0	0.03	0.45	0.05
31580	Water Gauges	2	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
31701	Superheater/High Pressure Section	152	0.53	240	0.11	53	0.10	12	0.06	1	0.05	0.75	0.67
31702	Reheater	62	0.33	65	0.06	0	0.01	9	0.05	0	0.01	0.41	0.42
31703	Economizer/Low Pressure Section	50	0.18	20	0.01	0	0.00	1	0.00	0	0.00	0.19	0.23
31810	Attemperation	2	0.01	50	0.04	3	0.01	3	0.01	0	0.01	0.05	0.01
31820	Burner Tilt	0	0.00	10	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
31832	Flue Gas-Recirculation Fans	3	0.02	67	0.07	3	0.01	4	0.03	0	0.01	0.10	0.03
31833	Recirculation Fans Variable Speed	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
31834	Flue Gas Recirculation Motors	0	0.00	11	0.02	0	0.00	1	0.01	0	0.00	0.03	0.00
32100	Forced Draft Ducts	2	0.00	4	0.00	3	0.01	1	0.00	0	0.00	0.01	0.00
32310	Forced Draft Fans	15	0.03	175	0.22	17	0.04	7	0.03	0	0.02	0.25	0.02
32320	Forced Draft Fan Variable Speed Coupling	3	0.01	12	0.01	0	0.00	0	0.00	0	0.00	0.01	0.01
32330	Forced Draft Fan Motors	3	0.01	25	0.04	1	0.01	1	0.01	0	0.01	0.04	0.02
32400	Induced Draft Flues	1	0.00	1	0.00	1	0.00	8	0.02	1	0.00	0.02	0.00
32510	Induced Draft Fans	40	0.16	1050	0.99	35	0.14	27	0.18	0	0.11	1.15	0.19
32520	Induced Draft Fan Variable Speed Coupling Drives	3	0.01	1	0.00	1	0.00	4	0.01	0	0.00	0.02	0.01
32530	Induced Draft Fan Motors	3	0.02	75	0.04	2	0.01	1	0.01	0	0.01	0.05	0.02
33100	Main Steam Piping	17	0.05	11	0.01	1	0.00	14	0.05	1	0.02	0.12	0.06
33200	Hot Reheat Piping	4	0.02	4	0.00	0	0.00	0	0.00	0	0.00	0.02	0.02
33300	Cold Reheat Piping	3	0.01	2	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01

Fossil - Coal Units

Table 6.2.8

Detail Component Outage Code Report, 2005 to 2009

Steam Generation

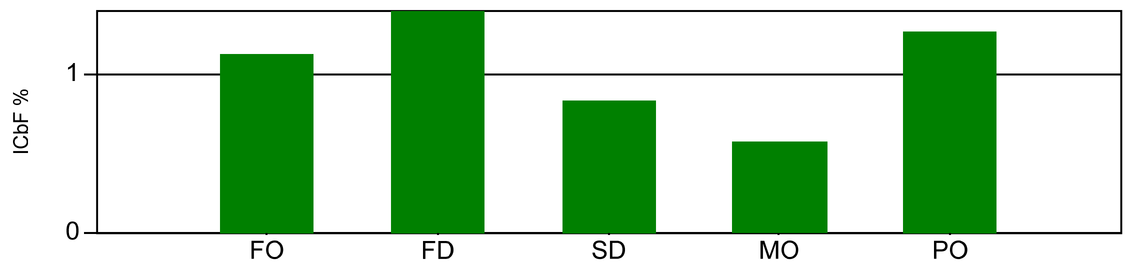
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Generation Facilities													
34200	Boiler Blowdown System	2	0.00	27	0.01	0	0.00	1	0.00	0	0.00	0.02	0.00
34400	Boiler Drains System	2	0.00	1	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
34500	Boiler Boiling-Out, Alkaline Flushing	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
35110	Furnace Ash Removal System	39	0.21	904	0.62	19	0.18	12	0.18	1	0.17	0.71	0.26
35120	Pulverizer Pyrites Removal System	1	0.01	291	0.06	9	0.01	0	0.01	0	0.01	0.07	0.01
35130	Fly Ash Removal System - Dry Transportation	1	0.02	142	0.09	8	0.02	3	0.04	0	0.02	0.12	0.03
35140	Fly Ash Removal System - Wet	0	0.00	14	0.01	4	0.01	2	0.00	0	0.00	0.01	0.00
35210	Precipitators-Electrostatic	27	0.36	2780	2.59	36	0.29	54	0.43	1	0.30	2.89	0.45
35220	Precipitators-Mechanical	1	0.00	4	0.01	0	0.00	1	0.00	0	0.00	0.01	0.00
35230	Precipitators-Baghouse	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
36100	Coal Receiving Systems	0	0.01	63	0.03	7	0.01	1	0.01	0	0.01	0.04	0.01
36200	Coal Storage Systems	1	0.04	647	0.17	35	0.04	1	0.04	1	0.04	0.18	0.04
36300	Coal Handling Systems	24	0.13	393	0.24	34	0.09	2	0.07	0	0.07	0.32	0.15
36370	Coal Stacker/Reclaimer Machine	1	0.00	6	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
36400	Coal Processing Systems	0	0.00	22	0.01	2	0.00	0	0.00	0	0.00	0.02	0.00
37100	Fuel Oil Receiving Systems	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37300	Fuel Oil Transfer Systems	0	0.00	0	0.00	3	0.00	0	0.00	0	0.00	0.00	0.00
37400	Fuel Oil Forwarding Systems	2	0.00	3	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37500	Fuel Oil Boosting Systems	0	0.00	1	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
38000	Sulphur Oxides Removal System	9	0.01	37	0.02	20	0.01	4	0.01	0	0.00	0.04	0.01
38300	IN-FURNACE BED LIMESTONE INJECTION SYS	0	0.00	1	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
38400	FLUID BED LIMESTONE INJECTION SYSTEM	0	0.00	62	0.04	0	0.00	0	0.00	0	0.00	0.04	0.01
Steam Generation Facilities Total		**1039**	**5.26**	**19401**	**14.10**	**2194**	**3.79**	**359**	**3.51**	**184**	**8.22**	**25.85**	**6.32**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Steam Turbine



Steam Turbine ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

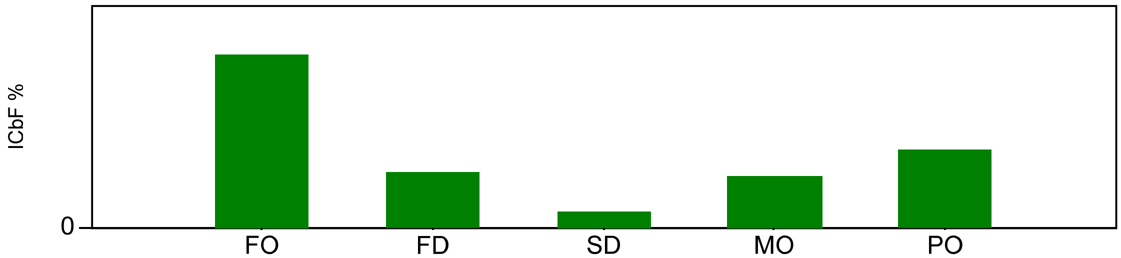
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Turbine													
41100	Turbine	126	0.68	331	1.03	191	0.14	38	0.27	37	0.89	2.75	0.83
41110	Cylinders	5	0.04	7	0.00	0	0.00	0	0.00	0	0.00	0.04	0.05
41120	Rotors	5	0.00	3	0.00	0	0.00	1	0.00	1	0.10	0.10	0.00
41121	Shaft Coupling Mechanism	1	0.00	0	0.00	0	0.00	0	0.00	1	0.01	0.02	0.00
41140	Crossover Piping	3	0.00	5	0.00	0	0.00	1	0.01	1	0.04	0.06	0.01
41150	Turning Gear	2	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41157	Turning Gear Motor	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41160	Valve Gear	36	0.09	86	0.08	51	0.03	15	0.08	0	0.02	0.21	0.11
41170	Bearings And Pedestals	26	0.03	59	0.03	1	0.01	4	0.04	1	0.05	0.12	0.03
41200	Lubricating Oil System	23	0.02	5	0.00	0	0.00	2	0.00	0	0.00	0.03	0.03
41500	Gland Seal System-Steam	10	0.03	2	0.00	1	0.00	5	0.01	1	0.00	0.05	0.04
41540	Gland Seal System-Water	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41600	Turbovisory	23	0.01	22	0.01	4	0.00	3	0.00	0	0.00	0.03	0.02
41700	Governing System	42	0.21	113	0.23	818	0.66	9	0.16	1	0.15	0.81	0.09
Steam Turbine Total		**303**	**1.11**	**634**	**1.38**	**1066**	**0.84**	**78**	**0.57**	**43**	**1.26**	**4.22**	**1.21**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Generators



Generators ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

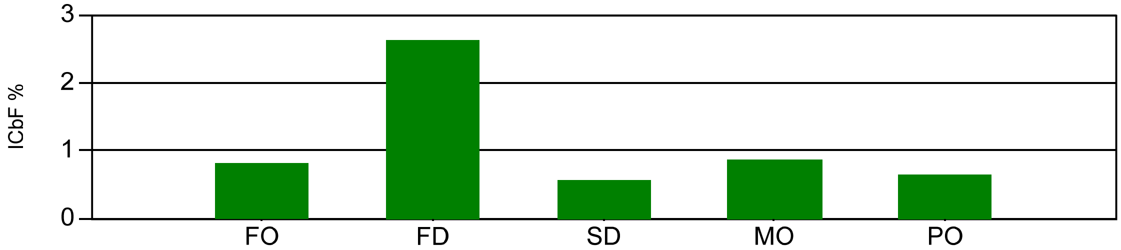
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Generators													
42100	Generator	19	0.11	32	0.03	26	0.01	5	0.01	7	0.06	0.21	0.14
42110	Generator Rotor	2	0.02	2	0.00	10	0.00	0	0.00	3	0.13	0.15	0.02
42111	Generator Bearings	8	0.04	44	0.01	0	0.00	1	0.00	0	0.00	0.05	0.05
42112	Generator Hydrogen Seals	10	0.07	3	0.00	0	0.00	5	0.03	0	0.00	0.10	0.08
42114	Generator Collector And Brushes	2	0.00	5	0.01	2	0.00	2	0.00	0	0.00	0.01	0.00
42120	Generator Stator	4	0.08	15	0.01	1	0.00	0	0.00	1	0.05	0.13	0.10
42200	Excitation Systems Equipment	35	0.03	20	0.02	9	0.00	13	0.01	0	0.00	0.05	0.03
42300	Hydrogen Gas Cooling System	18	0.07	80	0.09	22	0.03	5	0.10	1	0.03	0.23	0.09
42400	Generator Liquid Cooling System	8	0.21	40	0.02	2	0.00	4	0.02	0	0.00	0.24	0.27
42500	Seal Oil System	3	0.00	4	0.00	0	0.00	3	0.01	0	0.00	0.01	0.00
Generators Total		**109**	**0.63**	**245**	**0.19**	**72**	**0.04**	**38**	**0.18**	**12**	**0.27**	**1.18**	**0.78**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Heat Power Cycle



Heat Power Cycle ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

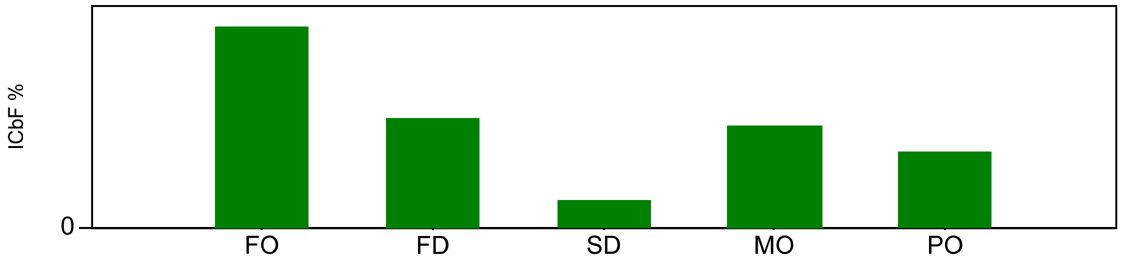
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Heat Power Cycle													
43090	Boiler Feedwater Piping And Supports	24	0.03	21	0.02	0	0.00	11	0.02	0	0.00	0.06	0.04
43100	High Pressure Feedwater Heaters And	33	0.09	350	0.42	8	0.06	27	0.11	2	0.08	0.57	0.12
43200	Boiler Feed Pumps And Auxiliaries	59	0.18	740	0.46	33	0.14	26	0.18	0	0.13	0.56	0.22
43260	Boiler Feed Pump Variable Speed Coupling	5	0.01	26	0.02	1	0.01	2	0.01	0	0.00	0.02	0.01
43300	Boiler Feed Pump Turbines & Auxiliaries	14	0.07	170	0.18	16	0.06	8	0.07	0	0.05	0.21	0.08
43400	Boiler Feed Pump Motors And Auxiliaries	9	0.05	59	0.15	2	0.05	0	0.05	0	0.05	0.15	0.07
44090	Condensate Piping And Supports	7	0.01	20	0.02	1	0.00	2	0.00	0	0.00	0.03	0.01
44110	Condensor	17	0.05	315	0.35	9	0.04	22	0.07	1	0.04	0.42	0.07
44120	Condensor Tubes	37	0.16	638	0.51	89	0.13	92	0.21	1	0.14	0.78	0.18
44200	Condensate Extraction Pumps And	11	0.07	218	0.27	22	0.07	7	0.07	0	0.06	0.30	0.09
44300	Condensate Extraction Pump Motors And	1	0.00	26	0.03	2	0.01	0	0.00	0	0.00	0.03	0.01
44400	Low Pressure Feedwater Heaters And	7	0.01	57	0.10	2	0.01	1	0.01	0	0.01	0.11	0.02
44500	Deaerator, Storage Tank, And Auxiliaries	21	0.03	35	0.02	2	0.00	9	0.03	2	0.05	0.12	0.04
45000	Air Extraction System	9	0.01	19	0.01	0	0.00	0	0.00	0	0.00	0.02	0.01
45090	Air Extraction System And Piping Support	1	0.00	4	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
45100	Air Extraction System Vacuum Pumps	9	0.00	20	0.00	1	0.00	1	0.00	0	0.00	0.01	0.00
45200	Air Extraction System Vacuum Pump, Motor and Auxiliaries	4	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
45300	Steam Air Ejectors	4	0.01	5	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
46100	Turbine Bypass System	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
47000	Condensate Make-up System	4	0.00	4	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48000	Feed Cycle Auxiliary Systems	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48100	Extraction Steam System	2	0.01	12	0.01	0	0.00	2	0.00	0	0.00	0.02	0.01
48200	Feedwater Heater Drains System	4	0.00	21	0.03	2	0.00	4	0.01	0	0.00	0.04	0.01
48400	Feedwater Heater Relief Valve, Vent	1	0.00	35	0.03	4	0.00	1	0.00	0	0.00	0.03	0.00
48500	Turbine And Piping Drains	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.01	0.00
Heat Power Cycle Total		**285**	**0.79**	**2796**	**2.64**	**194**	**0.58**	**216**	**0.84**	**6**	**0.61**	**3.51**	**1.00**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Electrical Power Sys.



Electrical Power System ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

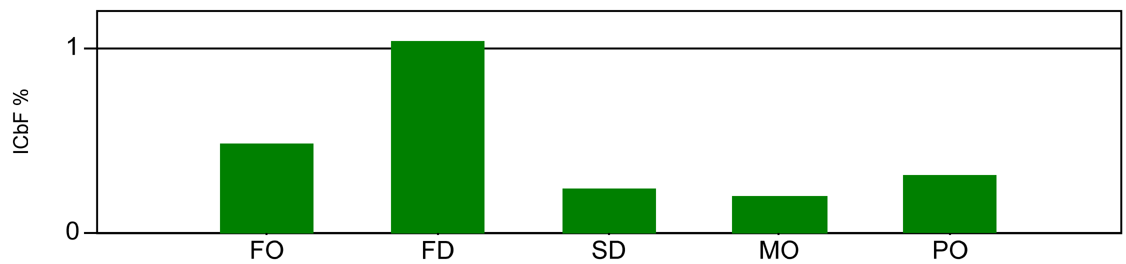
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Electrical Power System													
51100	Output System Generator Voltage Equipment	11	0.01	8	0.00	17	0.00	0	0.00	3	0.00	0.01	0.01
51120	Generator Power Transformers	34	0.07	58	0.04	5	0.01	2	0.01	1	0.01	0.11	0.09
51130	Switching Equipment-Generator Voltage	2	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
51133	Circuit Breakers-Generator Voltage	5	0.00	3	0.00	0	0.00	0	0.00	3	0.00	0.00	0.00
51136	Disconnect Switches-Generator Voltage	3	0.00	1	0.00	0	0.00	0	0.00	1	0.00	0.00	0.00
51150	Bus Duct, Bus, Cable	2	0.00	0	0.00	0	0.00	1	0.01	2	0.02	0.03	0.00
51151	Bus Duct Cooling System	0	0.00	4	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51170	Generator Neutral Grounding Equipment	6	0.00	5	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
52100	Generator Voltage Supply System	6	0.01	7	0.00	2	0.00	0	0.00	1	0.01	0.02	0.01
52120	Station Service Transformer	8	0.01	15	0.01	8	0.00	0	0.00	0	0.00	0.02	0.01
52130	Unit Service Transformer	9	0.01	36	0.02	1	0.00	8	0.01	0	0.00	0.04	0.01
52140	Exciter XFMR	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
53200	Station Service Power Distribution	46	0.10	89	0.04	6	0.01	18	0.07	2	0.03	0.22	0.13
55000	Direct Current Power Supplies	9	0.01	3	0.00	0	0.00	7	0.01	1	0.01	0.02	0.01
Electrical Power System Total		**142**	**0.22**	**231**	**0.11**	**39**	**0.02**	**37**	**0.11**	**14**	**0.08**	**0.47**	**0.27**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Ins. and Control



Instrumentation and Control ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

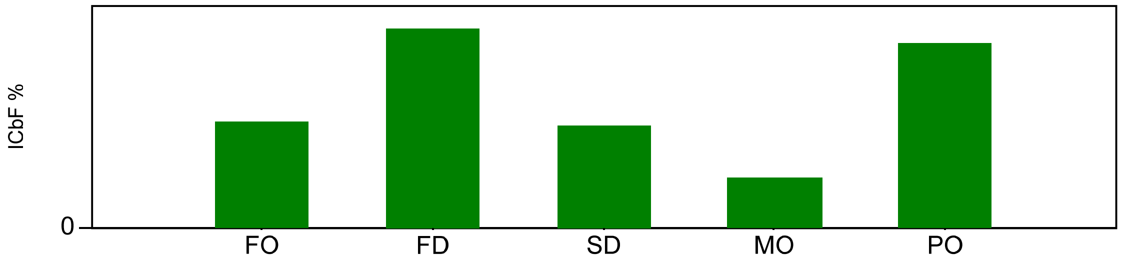
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Instrumentation and Control													
63100	Steam Generator Controls	112	0.09	796	0.49	340	0.11	13	0.07	0	0.06	0.60	0.10
63200	Equipment Controls-Furnace Draft	9	0.02	169	0.19	4	0.02	0	0.02	0	0.02	0.19	0.03
63300	Primary Steam Instrumentation & Control	4	0.00	19	0.01	6	0.00	0	0.00	0	0.00	0.01	0.00
63400	Auxiliary Systems -Instrumentation and Control	5	0.00	9	0.01	3	0.00	2	0.00	0	0.00	0.01	0.00
63500	Waste Removal Systems - Instrumentation and Control	0	0.00	6	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
63600	Fuel Coal Management - Instrumentation and Control	15	0.01	133	0.05	1	0.01	1	0.01	0	0.01	0.06	0.01
63700	Fuel Oil Management - Instrumentation	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
63800	Sulphur Oxide Removal System - Instrumentation and Control	0	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
63900	Ignition Fuel,Fuel Gas, & Miscellaneous	21	0.01	16	0.01	1	0.00	0	0.00	1	0.01	0.02	0.01
64100	Steam Turbine And Auxiliaries -	51	0.03	47	0.05	14	0.01	16	0.02	0	0.01	0.08	0.03
64200	Generator And Auxiliaries - Instrumentation and Control	31	0.07	59	0.09	12	0.04	1	0.04	2	0.14	0.23	0.09
64300	Boiler Feedwater System -Instrumentation and Control	60	0.03	88	0.05	4	0.01	2	0.01	0	0.01	0.07	0.04
64400	Condensate System - Instrumentation and Control	9	0.02	20	0.01	1	0.00	0	0.00	0	0.00	0.03	0.02
64500	Condensate Air Extraction System - Instrumentation and Control	5	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64700	Condensate Make-up system - Instrumentation and Control	1	0.00	7	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64800	Feedwater Heating Anciliary Systems - Instrumentation and Control	4	0.01	28	0.04	0	0.01	0	0.01	0	0.01	0.04	0.01
65100	Main Power Output Systems - Control and Protection	18	0.01	12	0.01	2	0.00	1	0.00	3	0.00	0.02	0.01
65200	Station Service Main Transformation - Control and Protection	7	0.00	5	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
65300	Alternating Current Power Distribution - Control and Protection	14	0.01	15	0.00	1	0.00	0	0.00	0	0.00	0.01	0.01
65500	Direct Current Power Distribution - Control and Protection	15	0.01	1	0.00	0	0.00	1	0.00	0	0.00	0.01	0.02
65900	System Control Facilities	1	0.00	2	0.00	2	0.00	0	0.00	0	0.00	0.00	0.00
67000	Plant Auxiliary Processes And Services - Instrumentation and Control	9	0.01	38	0.03	16	0.01	0	0.01	0	0.01	0.04	0.01
69000	Computers	56	0.13	20	0.01	8	0.01	4	0.01	3	0.05	0.19	0.16
Instrumentation and Control Total		**448**	**0.46**	**1491**	**1.05**	**416**	**0.23**	**41**	**0.20**	**9**	**0.33**	**1.62**	**0.56**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8

Auxiliary Processes



Plant Aux. Processes and Services ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

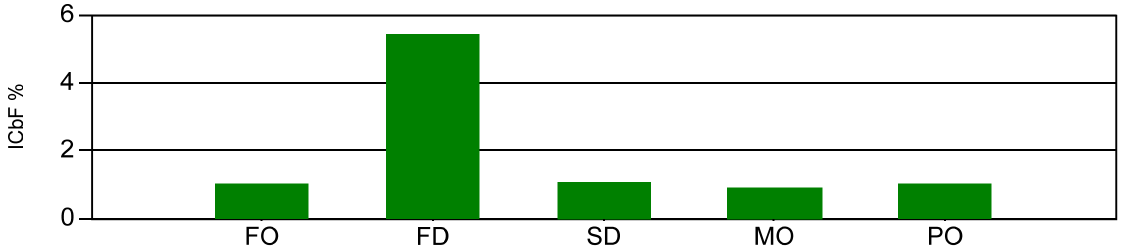
Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

CODE	CAUSE	Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
		NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Plant Aux. Processes and Services													
71000	Circulating Water Systems	7	0.03	68	0.03	10	0.01	4	0.01	0	0.00	0.07	0.03
71110	Travelling Water Screens	5	0.01	68	0.04	2	0.01	1	0.01	0	0.01	0.04	0.02
71120	Circulating Water Pumps	5	0.04	61	0.05	2	0.01	1	0.01	0	0.01	0.08	0.05
71127	Circulating Water Pump Motors	1	0.00	6	0.01	1	0.00	0	0.00	0	0.00	0.01	0.00
71140	Circulating Water Main Butterfly Valves and Operators	2	0.00	13	0.01	1	0.00	1	0.00	0	0.00	0.01	0.01
71190	Circulating Water Piping And Supports	1	0.00	13	0.01	2	0.00	2	0.00	1	0.00	0.01	0.00
71500	Circulating Water Screenwash System	0	0.00	4	0.00	1	0.00	1	0.00	0	0.00	0.00	0.00
71700	Circulating Water Cooling Towers	0	0.01	154	0.15	0	0.01	1	0.01	0	0.01	0.16	0.01
71800	Circulating Water Cooling Ponds	0	0.00	96	0.06	0	0.00	0	0.00	0	0.00	0.06	0.01
72000	Service Water Systems	3	0.04	8	0.00	1	0.00	4	0.02	2	0.07	0.13	0.05
72100	Service Water Low Pressure Open System	4	0.00	3	0.00	0	0.00	2	0.01	1	0.02	0.04	0.00
72800	Ash Transport Water Systems	1	0.05	15	0.05	0	0.02	0	0.02	0	0.02	0.09	0.06
73100	Auxiliary Steam And Condensate Systems	5	0.00	9	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
73200	Powerhouse Heating & Ventilating Systems	2	0.01	4	0.01	261	0.16	0	0.01	0	0.01	0.17	0.00
74000	Water Treatment Plant	9	0.03	15	0.01	0	0.00	1	0.00	4	0.15	0.18	0.04
75000	Compressed Air Systems	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
75110	Service Air System	1	0.00	1	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
75120	Instrument Air System	4	0.00	9	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
76000	Miscellaneous Services	1	0.00	0	0.00	2	0.00	0	0.00	2	0.10	0.11	0.00
78000	Fire Protection Systems	0	0.00	7	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
Plant Aux. Processes and Services Total		**52**	**0.22**	**554**	**0.44**	**283**	**0.22**	**19**	**0.10**	**10**	**0.40**	**1.17**	**0.28**

Fossil - Coal Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.8
Conditions



Conditions ICbF by event type for Fossil units based on 2005-2009 data.

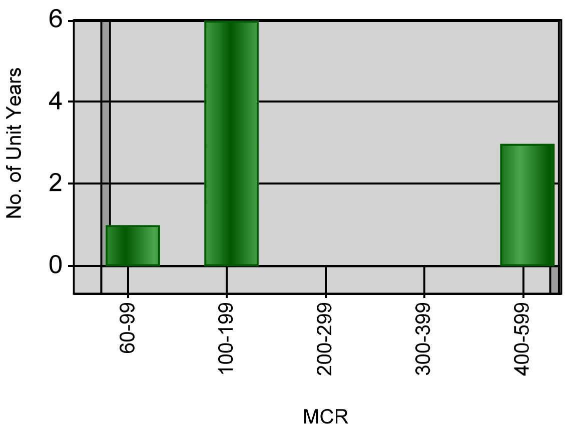
UNIT STATISTICS

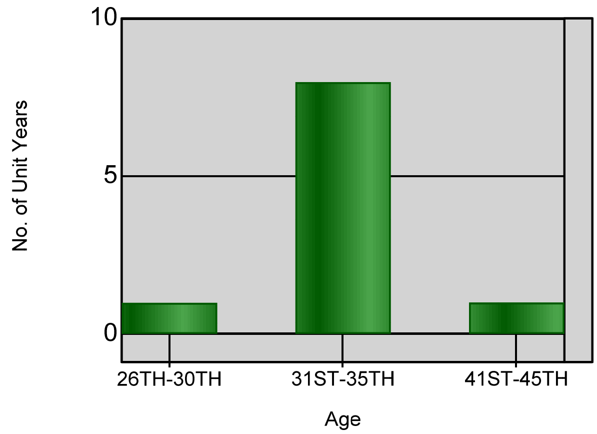
Number of Units:	64.00
Number of Unit Years:	296.68
Overall Operating Factor:	73.04

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
00500	Regulatory Bodies	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
01410	Poor Quality Fuel, Heat Content	8	0.46	3394	2.44	130	0.64	0	0.46	0	0.46	2.62	0.57
01420	Problems - Primary Fuel for Units with Secondary Fuel Op.	1	0.02	275	0.18	5	0.03	0	0.02	0	0.02	0.18	0.03
04200	Synchronous Condenser Operation	0	0.00	0	0.00	0	0.00	0	0.00	1	0.00	0.00	0.00
05200	Transmission Limitations	20	0.12	142	0.30	54	0.10	4	0.10	0	0.10	0.33	0.15
05201	Powerhouse Substation	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
05202	Transmission Line	3	0.00	3	0.00	0	0.00	0	0.00	0	0.00	0.01	0.00
07010	Site Environment, Storms, Floods	5	0.00	24	0.01	3	0.00	0	0.00	0	0.00	0.01	0.01
07110	Nitrous Oxides - Environmental Restriction	0	0.00	5	0.00	3	0.00	0	0.00	0	0.00	0.00	0.00
07120	Sulphur Dioxide - Environmental	4	0.03	698	0.14	2	0.03	0	0.03	0	0.03	0.14	0.04
07130	Particulates - Environmental Restriction	5	0.20	5661	2.06	3	0.19	0	0.19	0	0.19	2.06	0.25
07210	Cooling Water Discharge - Thermal Effects	4	0.08	213	0.26	4	0.07	0	0.07	0	0.07	0.27	0.10
07220	Liquid And Chemical Effluents	0	0.00	0	0.00	0	0.00	1	0.00	1	0.00	0.01	0.00
07230	Solid Waste Effluents	0	0.00	3	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
08160	Fire, General	5	0.07	12	0.00	0	0.00	0	0.00	0	0.00	0.07	0.08
08940	Labour Troubles	1	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
99999	Other	14	0.02	50	0.04	6	0.01	1	0.02	6	0.15	0.23	0.02
Conditions Total		**71**	**1.00**	**10482**	**5.43**	**211**	**1.07**	**6**	**0.89**	**8**	**1.02**	**5.93**	**1.25**

Fossil - Oil Units — Table 6.2.9

External Causes Excluded, 2009 Data

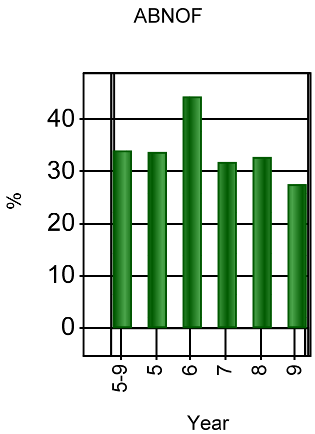


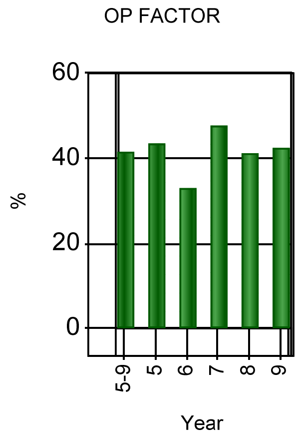


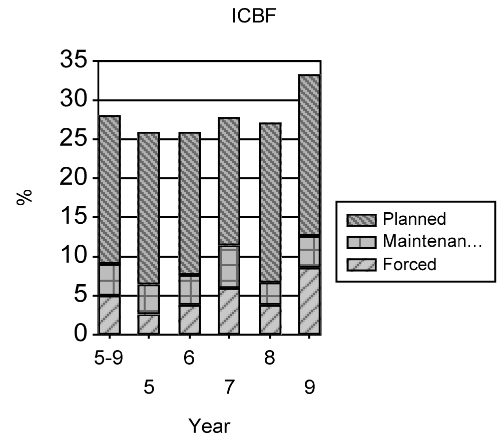
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	1.0	6.49	0.00	47.46	5	0.3	1927.08	475.42	36.38	37.65	37.65	0.5	46.99	6.32	13.14	5.77
100-199	6.0	9.19	7.83	59.59	30	0.4	1781.35	131.35	11.14	13.02	12.69	2.0	32.61	6.43	1.05	22.45
200-299	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
300-399	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
400-599	3.0	71.25	0.00	6.07	10	0.0	104.32	11.64	6.80	7.98	6.80	0.7	22.26	16.46	3.25	18.41
Classification By Year Of Service																
26TH-30TH	1.0	18.98	46.99	33.63	4	0.0	176.50	59.07	7.20	7.45	7.15	0.5	46.35	5.95	3.33	40.22
31ST-35TH	8.0	31.24	0.00	42.77	36	0.4	1781.35	106.13	11.30	13.30	12.98	2.2	27.01	7.01	1.59	18.71
41ST-45TH	1.0	6.49	0.00	47.46	5	0.3	1927.08	475.42	36.38	37.65	37.65	0.5	46.99	6.32	13.14	5.77
Classification By Operating Factor																
0-10	3.0	71.25	0.00	6.07	10	0.0	104.32	11.64	6.80	7.98	7.08	0.7	22.26	16.46	3.25	18.41
31-40	1.0	18.98	46.99	33.63	4	0.0	176.50	59.07	7.20	7.45	7.15	0.5	46.35	5.95	3.33	40.22
41-50	1.0	6.49	0.00	47.46	5	0.3	1927.08	475.42	36.38	37.65	37.65	0.5	46.99	6.32	13.14	5.77
51-60	2.0	15.05	0.00	53.89	12	0.1	855.25	99.79	11.26	15.44	14.86	0.7	33.91	7.42	0.34	23.88
61-70	1.0	4.58	0.00	61.90	2	0.0	104.98	54.26	1.96	2.26	2.25	0.3	33.70	3.23	0.77	31.51
71-80	1.0	1.47	0.00	72.84	6	0.2	1781.35	311.67	22.66	22.68	22.54	0.3	25.71	8.24	1.54	2.81
81-90	1.0	0.00	0.00	81.42	6	0.1	350.33	88.02	6.88	9.38	9.16	0.2	22.11	6.14	0.00	12.38
All Units	**10.0**	**27.54**	**4.70**	**42.32**	**45**	**0.7**	**1,927.08**	**142.98**	**14.75**	**16.50**	**15.96**	**3.1**	**30.94**	**6.85**	**2.92**	**19.57**

Fossil - Oil Units
Table 6.2.10

External Causes Excluded, 2005 to 2009 Data







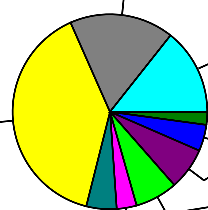
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	5.0	35.88	0.00	42.92	15	0.3	1927.08	174.76	12.23	12.62	12.27	1.1	21.39	5.59	3.21	12.01
100-199	29.2	14.92	5.11	56.41	181	1.3	1781.35	63.59	7.09	9.78	9.56	8.6	28.93	9.02	2.35	20.27
200-299	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
300-399	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
400-599	14.9	70.25	0.00	10.11	55	0.2	480.03	31.32	11.36	12.68	11.62	2.9	19.30	12.46	3.08	14.64
Classification By Year Of Service																
21ST-25TH	0.9	16.70	11.69	48.52	8	0.0	32.60	16.52	2.48	9.68	7.72	0.3	26.76	11.86	2.02	18.01
26TH-30TH	28.3	32.89	4.89	41.20	165	0.8	878.76	40.73	5.93	8.87	8.58	7.4	25.95	10.57	2.70	19.11
31ST-35TH	15.0	35.76	0.00	39.72	63	0.7	1781.35	101.27	10.87	12.30	12.02	3.8	25.14	6.54	2.44	17.00
36TH-40TH	1.0	36.43	0.00	48.00	1	0.0	13.38	13.38	0.32	0.32	0.3	0.2	15.57	2.08	0.88	14.54
41ST-45TH	4.0	35.74	0.00	41.65	14	0.3	1927.08	186.29	15.15	15.63	15.36	0.9	22.84	6.60	3.79	11.38
Classification By Operating Factor																
0-10	14.9	70.25	0.00	10.11	55	0.2	480.03	31.32	11.36	12.68	11.6	2.9	19.30	12.46	3.08	14.64
31-40	5.5	18.91	26.70	38.73	28	0.1	177.62	28.86	3.80	7.05	6.46	2.4	41.33	9.10	3.35	34.70
41-50	14.8	20.33	0.00	47.73	81	1.0	1927.08	107.04	11.88	16.06	15.59	5.0	33.26	8.65	1.87	22.28
51-60	5.0	26.71	0.00	57.01	10	0.0	104.98	21.04	0.84	0.90	0.9	0.8	16.31	3.51	2.91	12.87
61-70	4.9	15.26	0.00	65.44	23	0.3	1781.35	121.89	8.60	9.11	9.06	0.9	17.05	5.50	3.97	6.29
81-90	4.0	0.00	0.00	85.17	54	0.2	350.33	30.36	5.18	6.81	6.59	0.7	16.29	15.54	1.07	8.61
All Units	**49.1**	**33.73**	**3.05**	**41.07**	**251**	**1.8**	**1,927.08**	**63.16**	**7.97**	**10.31**	**9.99**	**12.6**	**25.26**	**8.91**	**2.66**	**17.74**

Fossil - Oil Units

Major Component Outage Code Report, 2005 to 2009

Table 6.2.11

Major Componenent Contribution to Oil-Fired Fossil Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	14.00
Number of Unit Yars:	53.71
Overall Operating Factor:	41.30

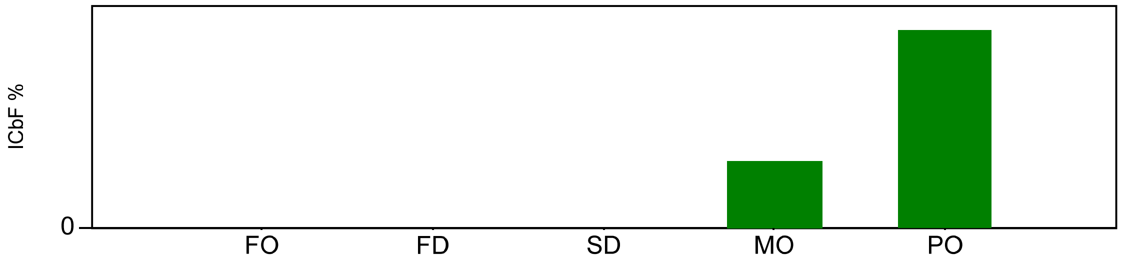
	FORCED OUTAGES		FORCED DERATINGS		SCHEDULED DERATINGS		MAINTENANCE OUTAGES		PLANNED OUTAGES		CONTRIBUTION TO UNIT		
MAJOR COMPONENT	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	FOR (%)	DAFOR (%)
Buildings and Structures	0	0.00	0	0.00	0	0.00	8	0.05	3	0.14	0.19	0.00	0.00
Conditions	15	0.76	18	0.31	6	0.06	10	0.09	0	0.05	1.08	1.57	1.67
Electrical Power System	14	0.53	3	0.00	0	0.00	14	0.10	7	0.10	0.74	1.19	1.18
Generators	16	0.74	5	0.01	25	0.01	4	0.29	3	1.07	2.08	1.59	1.59
Heat Power Cycle	30	0.33	63	0.77	12	0.19	39	0.67	3	1.14	2.54	0.40	0.66
Instrumentation and Control	37	0.11	37	0.15	10	0.08	1	0.05	1	0.06	0.26	0.14	0.22
Plant Aux. Processes and Services	6	0.09	23	0.71	3	0.08	11	0.26	2	0.18	1.03	0.04	0.22
Steam Generation Facilities	78	2.23	240	4.41	38	1.10	72	1.81	46	10.63	16.68	2.94	4.66
Steam Turbine	45	0.81	35	0.14	25	0.06	18	0.63	27	5.61	7.08	1.69	1.76
TOTAL (External Causes Included)	241	5.60	424	6.50	119	1.58	177	3.95	92	18.98	31.68	9.56	11.96
TOTAL (External Causes Excluded)	227	4.93	410	6.31	113	1.59	169	3.91	92	19.19	30.95	8.14	10.52

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Building and Structure



Buildings and Structures ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

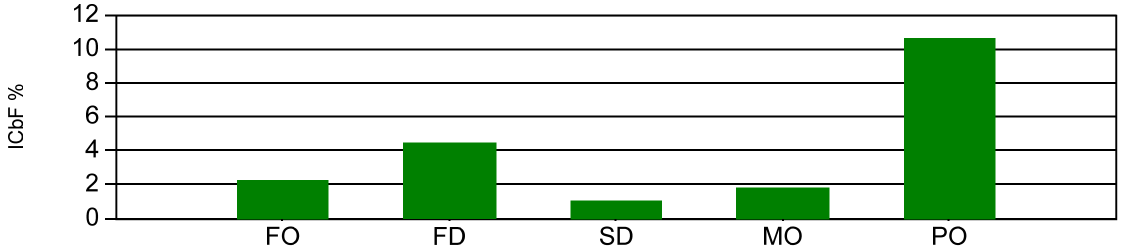
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Buildings and Structures													
23290	Chimney	0	0.00	0	0.00	0	0.00	8	0.05	3	0.14	0.19	0.00
Buildings and Structures Total		**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**8**	**0.05**	**3**	**0.14**	**0.19**	**0.00**

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Steam Generation



Steam Generation Facilities ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

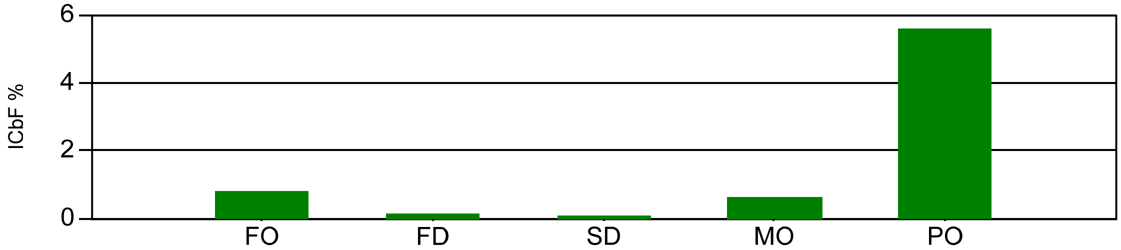
Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Steam Generation Facilities													
31000	Steam Generator/HRSG	14	0.27	38	0.51	1	0.12	4	0.17	40	9.03	9.63	0.59
31150	Air Heaters	2	0.13	31	1.01	0	0.11	24	0.35	0	0.11	1.26	0.28
31220	Pulverized Fuel Burner Piping And Valves	0	0.00	7	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
31270	Burners And Windboxes	3	0.02	3	0.05	1	0.01	0	0.01	0	0.01	0.06	0.04
31280	Igniters	2	0.00	4	0.01	0	0.00	0	0.00	0	0.00	0.01	0.01
31300	Sootblower Systems	0	0.00	2	0.01	0	0.00	2	0.02	0	0.00	0.03	0.00
31530	Steam Generating Tubes (Between Steam Drum and Mud Drum)	2	0.06	1	0.13	0	0.04	4	0.12	0	0.04	0.24	0.12
31540	Waterwalls	8	0.23	0	0.00	0	0.00	13	0.26	0	0.00	0.49	0.51
31550	Circulating Pumps	0	0.04	11	0.16	0	0.04	0	0.04	0	0.04	0.16	0.10
31570	Safety Valves	2	0.28	8	0.36	20	0.28	2	0.10	0	0.09	0.74	0.44
31580	Water Gauges	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
31701	Superheater/High Pressure Section	8	0.20	2	0.00	0	0.00	2	0.07	1	0.28	0.54	0.43
31702	Reheater	9	0.19	1	0.00	1	0.00	1	0.01	1	0.06	0.26	0.41
31703	Economizer/Low Pressure Section	2	0.03	0	0.00	0	0.00	2	0.01	0	0.00	0.04	0.06
31810	Attemperation	0	0.01	8	0.02	1	0.01	2	0.04	0	0.01	0.05	0.01
31832	Flue Gas-Recirculation Fans	1	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0.09	0.20
32100	Forced Draft Ducts	0	0.04	11	0.72	0	0.04	3	0.05	0	0.04	0.73	0.09
32310	Forced Draft Fans	13	0.56	21	0.93	1	0.37	3	0.38	0	0.37	1.13	1.22
32330	Forced Draft Fan Motors	0	0.01	1	0.04	1	0.02	0	0.01	0	0.01	0.05	0.00
32400	Induced Draft Flues	0	0.00	0	0.00	0	0.00	2	0.04	0	0.00	0.04	0.00
32510	Induced Draft Fans	4	0.03	13	0.19	2	0.03	1	0.03	0	0.02	0.21	0.05
32530	Induced Draft Fan Motors	0	0.01	66	0.26	0	0.01	0	0.01	0	0.01	0.26	0.02
33100	Main Steam Piping	1	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0.02	0.04
34100	Furnace And Water Gauge Television	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
34400	Boiler Drains System	1	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.01
35130	Fly Ash Removal System - Dry Transportation	0	0.00	0	0.00	0	0.00	2	0.06	0	0.00	0.06	0.00
35140	Fly Ash Removal System - Wet	0	0.00	0	0.00	6	0.02	3	0.01	0	0.00	0.03	0.00
35210	Precipitators-Electrostatic	0	0.00	0	0.00	0	0.00	0	0.00	1	0.15	0.15	0.00
35220	Precipitators-Mechanical	0	0.00	0	0.00	0	0.00	0	0.00	1	0.29	0.29	0.00
36100	Coal Receiving Systems	1	0.00	7	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
37300	Fuel Oil Transfer Systems	0	0.00	0	0.00	3	0.00	0	0.00	2	0.07	0.07	0.00
37400	Fuel Oil Forwarding Systems	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37500	Fuel Oil Boosting Systems	2	0.01	2	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
37600	Fuel Oil Heating Systems	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
38000	Sulphur Oxides Removal System	2	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
Steam Generation Facilities Total		**78**	**2.23**	**240**	**4.41**	**38**	**1.10**	**72**	**1.81**	**46**	**10.63**	**16.68**	**4.66**

Canadian Electricity Association
Association canadienne de l'électricité

Fossil - Oil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12
Steam Turbine



Steam Turbine ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

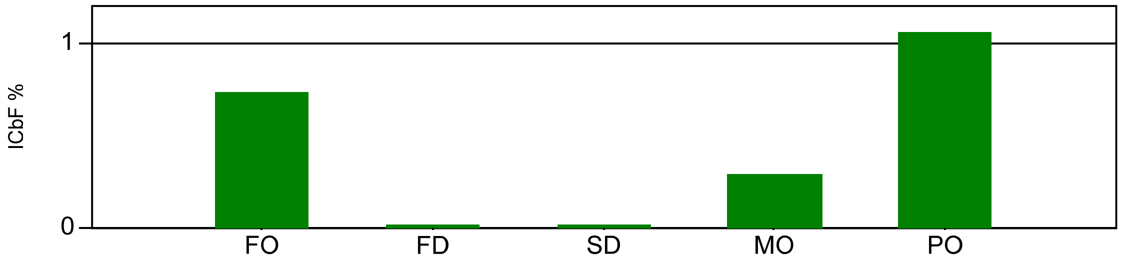
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Steam Turbine													
41100	Turbine	14	0.51	26	0.02	21	0.03	3	0.07	20	3.70	4.27	1.09
41120	Rotors	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
41121	Shaft Coupling Mechanism	1	0.01	0	0.00	0	0.00	4	0.24	6	1.60	1.85	0.02
41140	Crossover Piping	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41150	Turning Gear	2	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0.06	0.13
41160	Valve Gear	5	0.05	1	0.00	2	0.00	6	0.23	0	0.00	0.29	0.11
41170	Bearings And Pedestals	2	0.03	1	0.08	0	0.02	0	0.02	0	0.02	0.09	0.06
41200	Lubricating Oil System	4	0.02	2	0.03	0	0.01	2	0.05	0	0.01	0.08	0.05
41500	Gland Seal System-Steam	1	0.04	0	0.00	0	0.00	2	0.01	1	0.28	0.33	0.09
41600	Turbovisory	10	0.05	3	0.00	2	0.00	0	0.00	0	0.00	0.05	0.11
41700	Governing System	6	0.04	1	0.01	0	0.00	0	0.00	0	0.00	0.05	0.10
Steam Turbine Total		**45**	**0.81**	**35**	**0.14**	**25**	**0.06**	**18**	**0.63**	**27**	**5.61**	**7.08**	**1.76**

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Generators



Generators ICbF by event type for Fossil units based on 2005-2009 data.

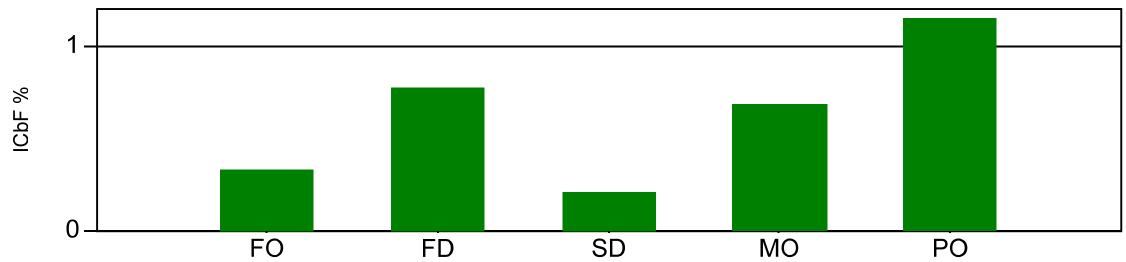
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Generators													
42100	Generator	2	0.04	2	0.00	1	0.00	0	0.00	0	0.00	0.04	0.09
42110	Generator Rotor	8	0.65	0	0.00	5	0.00	1	0.24	3	1.06	1.94	1.42
42114	Generator Collector And Brushes	0	0.00	0	0.00	0	0.00	1	0.03	0	0.00	0.03	0.00
42120	Generator Stator	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
42200	Excitation Systems Equipment	5	0.04	1	0.01	19	0.01	1	0.01	0	0.01	0.05	0.07
42300	Hydrogen Gas Cooling System	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
42400	Generator Liquid Cooling System	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
42500	Seal Oil System	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
Generators Total		**16**	**0.74**	**5**	**0.01**	**25**	**0.01**	**4**	**0.29**	**3**	**1.07**	**2.08**	**1.59**

Fossil - Oil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12
Heat Power Cycle



Heat Power Cycle ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

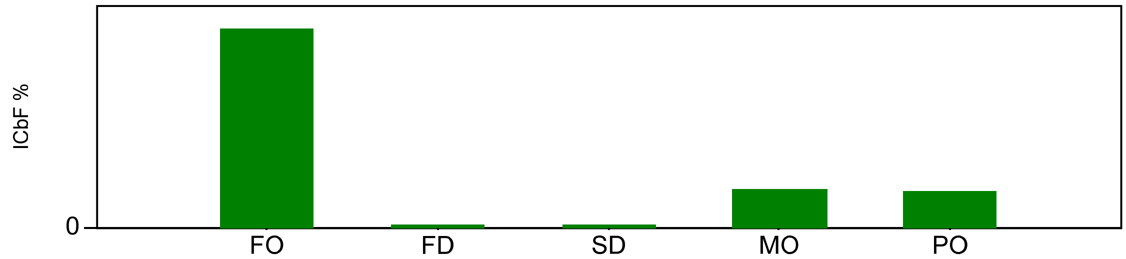
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Heat Power Cycle													
43090	Boiler Feedwater Piping And Supports	3	0.04	4	0.01	0	0.00	1	0.01	0	0.00	0.05	0.08
43100	High Pressure Feedwater Heaters And	4	0.05	9	0.15	2	0.04	4	0.05	1	0.27	0.47	0.10
43200	Boiler Feed Pumps And Auxiliaries	6	0.11	15	0.14	1	0.07	7	0.11	0	0.06	0.26	0.21
43260	Boiler Feed Pump Variable Speed Coupling	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0.01	0.00
43300	Boiler Feed Pump Turbines & Auxiliaries	0	0.01	5	0.02	1	0.01	0	0.01	0	0.01	0.03	0.02
43400	Boiler Feed Pump Motors And Auxiliaries	2	0.05	4	0.03	0	0.01	2	0.04	0	0.01	0.10	0.11
44090	Condensate Piping And Supports	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
44110	Condensor	4	0.01	1	0.01	3	0.02	0	0.01	2	0.76	0.77	0.01
44120	Condensor Tubes	2	0.04	18	0.39	3	0.03	20	0.29	0	0.03	0.66	0.08
44200	Condensate Extraction Pumps And	1	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
44300	Condensate Extraction Pump Motors And	0	0.00	2	0.02	0	0.00	0	0.00	0	0.00	0.02	0.01
44500	Deaerator, Storage Tank, And Auxiliaries	3	0.02	1	0.00	0	0.00	4	0.06	0	0.00	0.07	0.03
45000	Air Extraction System	4	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48100	Extraction Steam System	0	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
48500	Turbine And Piping Drains	1	0.00	0	0.00	0	0.00	1	0.09	0	0.00	0.10	0.01
Heat Power Cycle Total		**30**	**0.33**	**63**	**0.77**	**12**	**0.19**	**39**	**0.67**	**3**	**1.14**	**2.54**	**0.66**

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Electrical Power Sys.



Electrical Power System ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

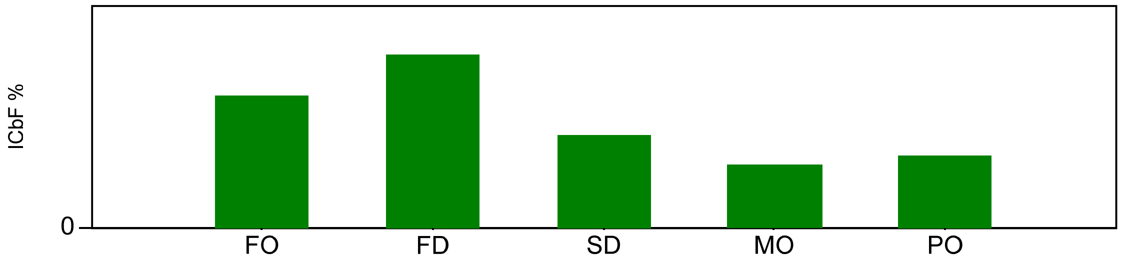
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Electrical Power System													
51120	Generator Power Transformers	3	0.10	1	0.00	0	0.00	7	0.03	6	0.07	0.20	0.22
51130	Switching Equipment-Generator Voltage	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51133	Circuit Breakers-Generator Voltage	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
51170	Generator Neutral Grounding Equipment	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
52100	Generator Voltage Supply System	1	0.41	0	0.00	0	0.00	0	0.00	0	0.00	0.41	0.89
52130	Unit Service Transformer	1	0.00	0	0.00	0	0.00	2	0.04	0	0.00	0.05	0.01
52140	Exciter XFMR	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0.02	0.05
53200	Station Service Power Distribution	4	0.00	1	0.00	0	0.00	3	0.01	0	0.00	0.02	0.01
55000	Direct Current Power Supplies	1	0.00	1	0.00	0	0.00	1	0.02	1	0.03	0.04	0.00
Electrical Power System Total		**14**	**0.53**	**3**	**0.00**	**0**	**0.00**	**14**	**0.10**	**7**	**0.10**	**0.74**	**1.18**

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Ins. and Control



Instrumentation and Control ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

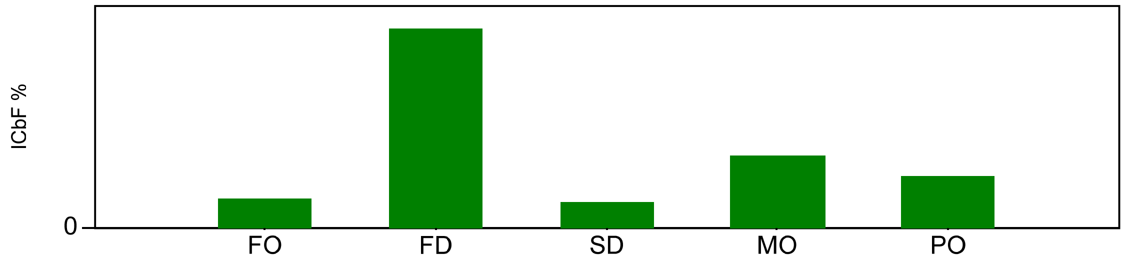
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Instrumentation and Control													
63100	Steam Generator Controls	12	0.02	20	0.05	1	0.01	0	0.01	0	0.01	0.06	0.04
63300	Primary Steam Instrumentation & Control	1	0.00	0	0.00	1	0.00	0	0.00	0	0.00	0.00	0.00
63700	Fuel Oil Management - Instrumentation	1	0.02	4	0.07	0	0.02	0	0.02	0	0.02	0.07	0.04
63900	Ignition Fuel,Fuel Gas, & Miscellaneous	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64100	Steam Turbine And Auxiliaries -	7	0.01	3	0.00	0	0.00	0	0.00	0	0.00	0.01	0.03
64200	Generator And Auxiliaries - Instrumentation and Control	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
64210	Supervisory Control & Data Acquisition	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
64300	Boiler Feedwater System -Instrumentation and Control	5	0.01	2	0.00	0	0.00	0	0.00	0	0.00	0.02	0.03
64800	Feedwater Heating Anciliary Systems - Instrumentation and Control	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
65100	Main Power Output Systems - Control and Protection	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.02
65500	Direct Current Power Distribution - Control and Protection	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
69000	Computers	6	0.04	7	0.03	8	0.05	0	0.02	1	0.03	0.09	0.06
Instrumentation and Control Total		**37**	**0.11**	**37**	**0.15**	**10**	**0.08**	**1**	**0.05**	**1**	**0.06**	**0.26**	**0.22**

Fossil - Oil Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12

Auxiliary Processes



Plant Aux. Processes and Services ICbF by event type for Fossil units based on 2005-2009 data.

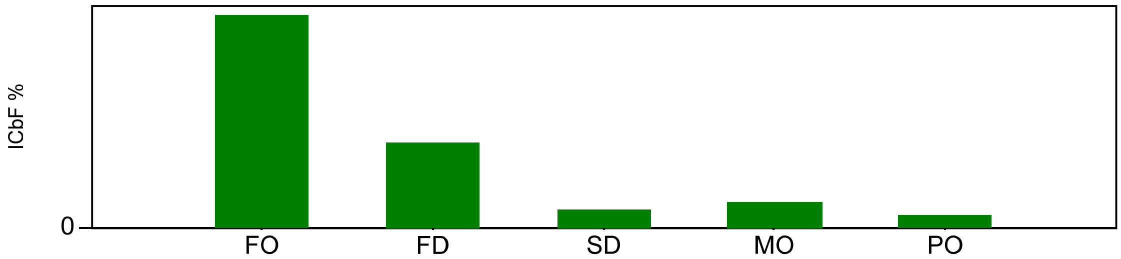
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

CODE	CAUSE	Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
		NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Plant Aux. Processes and Services													
71000	Circulating Water Systems	1	0.00	1	0.00	1	0.00	4	0.06	1	0.05	0.12	0.00
71110	Travelling Water Screens	0	0.00	2	0.00	0	0.00	1	0.05	0	0.00	0.05	0.00
71120	Circulating Water Pumps	1	0.00	1	0.00	1	0.00	0	0.00	0	0.00	0.01	0.01
71127	Circulating Water Pump Motors	0	0.08	15	0.70	0	0.08	0	0.08	0	0.08	0.70	0.18
71140	Circulating Water Main Butterfly Valves and Operators	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
71190	Circulating Water Piping And Supports	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
72100	Service Water Low Pressure Open System	1	0.01	0	0.00	0	0.00	1	0.00	0	0.00	0.01	0.02
73000	Heating, Ventilating, And Air	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
73100	Auxiliary Steam And Condensate Systems	0	0.00	1	0.01	1	0.00	0	0.00	0	0.00	0.01	0.00
73200	Powerhouse Heating & Ventilating Systems	0	0.00	0	0.00	0	0.00	2	0.06	0	0.00	0.06	0.00
74000	Water Treatment Plant	2	0.00	1	0.00	0	0.00	0	0.00	1	0.05	0.06	0.00
75000	Compressed Air Systems	0	0.00	0	0.00	0	0.00	2	0.01	0	0.00	0.01	0.00
78000	Fire Protection Systems	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
Plant Aux. Processes and Services Total		**6**	**0.09**	**23**	**0.71**	**3**	**0.08**	**11**	**0.26**	**2**	**0.18**	**1.03**	**0.22**

Fossil - Oil Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.12
Conditions



Conditions ICbF by event type for Fossil units based on 2005-2009 data.

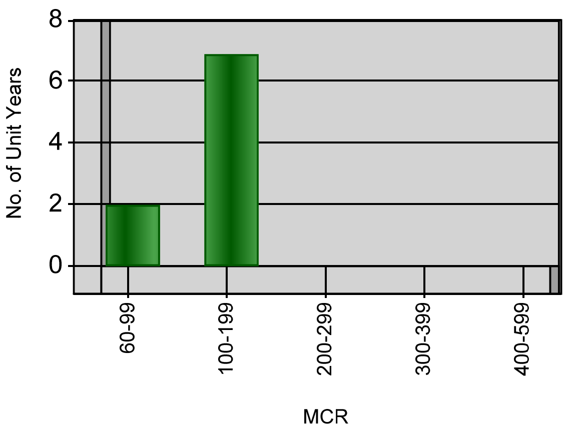
UNIT STATISTICS

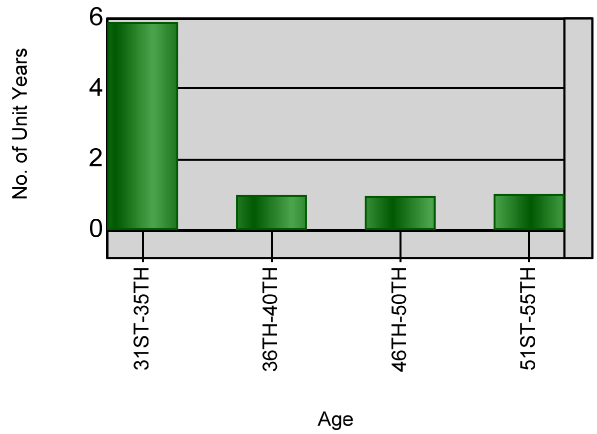
Number of Units:	14.00
Number of Unit Years:	53.71
Overall Operating Factor:	41.30

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
01410	Poor Quality Fuel, Heat Content	0	0.00	1	0.00	0	0.00	1	0.00	0	0.00	0.01	0.00
05200	Transmission Limitations	4	0.03	2	0.00	0	0.00	7	0.02	0	0.00	0.05	0.07
07010	Site Environment, Storms, Floods	4	0.34	15	0.31	6	0.06	1	0.07	0	0.05	0.63	0.73
07120	Sulphur Dioxide - Environmental	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
07130	Particulates - Environmental Restriction	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
08160	Fire, General	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0.03	0.07
08910	Staff Shortage	2	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0.10	0.22
99999	Other	3	0.26	0	0.00	0	0.00	0	0.00	0	0.00	0.26	0.58
Conditions Total		**15**	**0.76**	**18**	**0.31**	**6**	**0.06**	**10**	**0.09**	**0**	**0.05**	**1.08**	**1.67**

Fossil – Natural Gas
External Causes Excluded, 2009 Data

Table 6.2.13



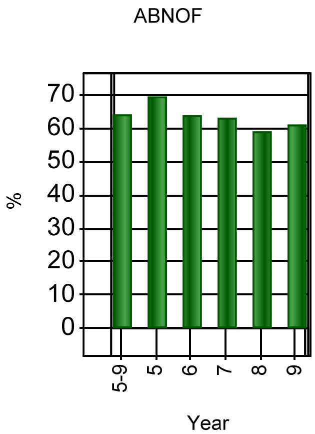


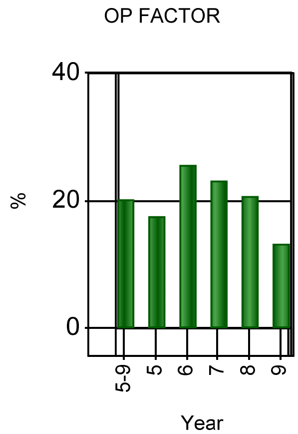
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	2.0	17.66	0.00	32.76	2	0.0	7.93	4.34	0.15	3.84	2.57	1.4	67.76	3.06	3.44	46.09
100-199	6.9	72.60	2.44	7.53	6	0.1	721.77	126.98	14.15	26.62	14.08	1.4	19.83	11.39	1.42	15.71
200-299	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
300-399	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
400-599	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
Classification By Year Of Service																
31ST-35TH	5.9	74.35	2.85	4.10	6	0.1	721.77	126.98	26.04	43.96	19.55	1.3	21.50	24.40	0.02	18.33
36TH-40TH	1.0	62.10	0.00	28.09	0	0.0	0.00	0.00	0.00	0.00	0	0.1	9.81	0.00	9.81	0.00
46TH-50TH	1.0	3.17	0.00	1.88	0	0.0	0.00	0.00	0.00	0.00	0	0.9	96.70	0.00	0.00	94.95
51ST-55TH	1.0	31.33	0.00	61.89	2	0.0	7.93	4.34	0.16	3.95	2.64	0.4	40.46	3.15	6.68	0.00
Classification By Operating Factor																
0-10	2.0	57.40	0.00	7.58	6	0.1	721.77	126.98	36.46	43.89	28.65	0.7	35.92	39.59	0.00	30.20
61-70	1.0	31.33	0.00	61.89	2	0.0	7.93	4.34	0.16	3.95	2.64	0.4	40.46	3.15	6.68	0.00
All Units	**8.9**	**60.42**	**1.90**	**13.12**	**8**	**0.1**	**721.77**	**96.32**	**6.93**	**15.64**	**8.42**	**2.7**	**30.46**	**6.78**	**1.87**	**22.44**

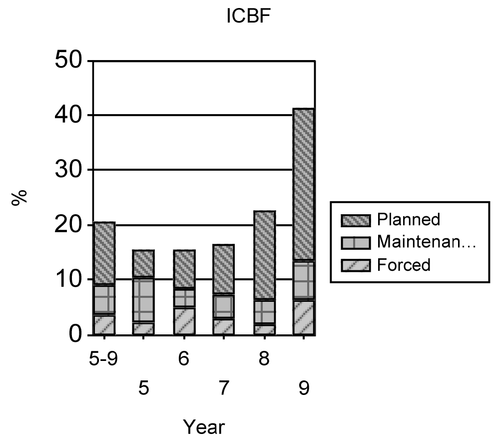
Fossil – Natural Gas

External Causes Excluded, 2005 to 2009 Data

Table 6.2.14







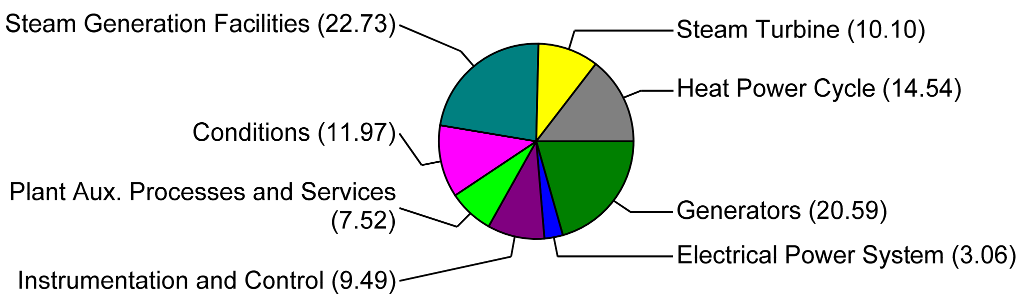
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
60-99	19.0	60.29	0.00	23.79	19	0.4	1737.25	171.28	7.58	12.18	11.81	3.7	19.46	3.76	8.12	5.81
100-199	38.5	65.83	11.14	18.39	37	0.6	1868.38	149.34	8.14	10.72	8.10	6.3	16.21	3.66	1.98	11.77
200-299	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
300-399	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
400-599	0.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.00
Classification By Year Of Service																
26TH-30TH	31.0	76.98	11.68	14.86	23	0.5	1868.38	171.97	8.92	9.19	7.9	2.6	8.29	2.82	1.18	5.37
31ST-35TH	14.6	65.10	4.70	11.20	15	0.2	786.22	104.75	9.83	19.17	8.5	3.6	24.56	8.52	1.47	20.25
36TH-40TH	2.0	47.38	0.00	43.50	1	0.0	0.03	0.03	0.00	0.00	0	0.2	9.11	1.15	9.11	0.00
46TH-50TH	9.0	24.82	0.00	43.21	15	0.4	1737.25	216.31	8.71	13.44	13.24	3.2	35.63	3.35	16.42	11.36
51ST-55TH	1.0	31.33	0.00	61.89	2	0.0	7.93	4.34	0.16	3.95	2.64	0.4	40.46	3.15	6.68	0.00
Classification By Operating Factor																
0-10	22.9	81.85	0.00	6.02	24	0.4	1868.38	152.24	23.19	25.06	22.13	2.8	12.25	11.58	1.58	8.43
11-20	5.0	71.77	20.88	15.51	4	0.0	142.58	39.47	2.26	10.14	2.23	0.7	13.83	2.58	0.48	11.59
21-30	4.8	55.23	33.63	28.72	3	0.0	50.78	21.97	0.54	0.54	0.54	0.8	15.73	2.16	0.03	14.56
31-40	9.9	44.59	16.58	35.68	8	0.2	1630.08	206.12	5.06	7.79	5.18	2.1	20.76	1.98	3.82	13.93
41-50	10.0	25.48	0.00	45.13	17	0.4	1737.25	191.37	7.60	12.19	11.87	3.6	36.12	3.32	15.42	10.19
All Units	**57.5**	**64.01**	**7.47**	**20.17**	**56**	**1.0**	**1,868.38**	**156.78**	**7.93**	**11.27**	**9.54**	**10.0**	**17.28**	**3.70**	**4.00**	**9.80**

Fossil - Natural Gas

Major Component Outage Code Report, 2005 to 2009 Data

Table 6.2.15

Major Componenent Contribution to Natural Gas-Fired Fossil Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	16.00
Number of Unit Yars:	61.67
Overall Operating Factor:	20.17

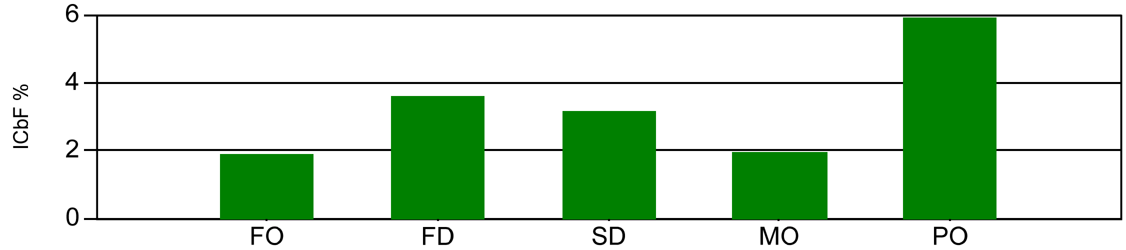
MAJOR COMPONENT	FORCED OUTAGES NO. OCC.	FORCED OUTAGES ICBF (%)	FORCED DERATINGS NO. OCC.	FORCED DERATINGS ICBF (%)	SCHEDULED DERATINGS NO. OCC.	SCHEDULED DERATINGS ICBF (%)	MAINTENANCE OUTAGES NO. OCC.	MAINTENANCE OUTAGES ICBF (%)	PLANNED OUTAGES NO. OCC.	PLANNED OUTAGES ICBF (%)	CONTRIBUTION TO UNIT ICBF (%)	CONTRIBUTION TO UNIT FOR (%)	CONTRIBUTION TO UNIT DAFOR (%)
Conditions	4	0.02	0	0.00	6	0.01	16	0.07	17	0.17	0.28	0.08	0.08
Electrical Power System	5	0.00	0	0.00	0	0.00	3	0.00	1	0.01	0.01	0.02	0.02
Generators	6	0.67	1	0.00	0	0.00	36	0.83	14	0.83	2.33	3.06	3.01
Heat Power Cycle	8	0.44	24	0.72	7	0.56	25	0.85	5	0.53	1.98	0.69	1.55
Instrumentation and Control	19	0.06	13	0.09	0	0.02	8	0.08	0	0.02	0.19	0.17	0.26
Plant Aux. Processes and Services	0	0.00	3	0.01	0	0.00	10	0.24	11	0.80	1.05	0.00	0.03
Steam Generation Facilities	8	1.90	118	3.60	101	3.19	21	1.98	32	5.93	11.27	2.56	5.00
Steam Turbine	5	0.39	2	0.08	11	1.20	12	1.75	8	3.39	6.48	1.43	1.41
TOTAL (External Causes Included)	55	3.48	161	4.50	125	4.98	131	5.80	88	11.68	23.59	8.01	11.36
TOTAL (External Causes Excluded)	54	3.48	161	4.53	119	5.00	118	5.75	72	11.57	23.38	7.93	11.28

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16

Steam Generation Fac.



Steam Generation Facilities ICbF by event type for Fossil units based on 2005-2009 data.

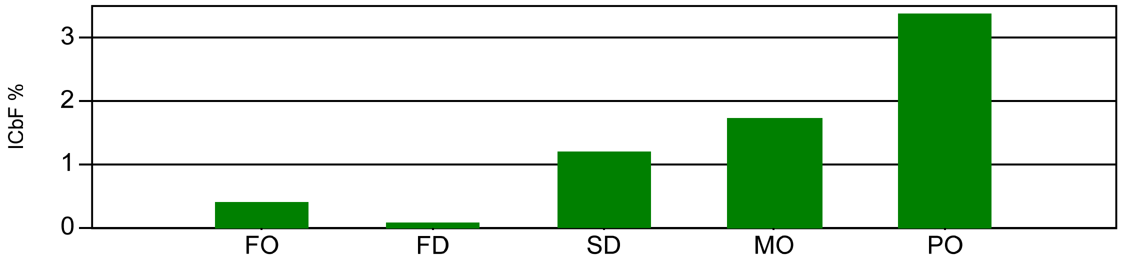
UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Generation Facilities													
31000	Steam Generator/HRSG	5	1.17	113	3.08	97	3.01	14	1.46	25	4.69	8.76	1.73
31240	Gas Burner Piping And Valves	0	0.00	1	0.00	0	0.00	1	0.01	7	1.07	1.08	0.00
31270	Burners And Windboxes	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
31510	Steam Drum - Scrubbers,Separators, Etc.	0	0.00	0	0.00	0	0.00	1	0.03	0	0.00	0.03	0.00
31540	Waterwalls	0	0.00	0	0.00	0	0.00	2	0.08	0	0.00	0.08	0.00
31570	Safety Valves	0	0.00	0	0.00	4	0.01	0	0.00	0	0.00	0.01	0.00
31701	Superheater/High Pressure Section	1	0.37	0	0.00	0	0.00	0	0.00	0	0.00	0.37	1.66
31703	Economizer/Low Pressure Section	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0.03	0.12
32310	Forced Draft Fans	0	0.17	2	0.52	0	0.17	0	0.17	0	0.17	0.52	0.78
32510	Induced Draft Fans	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
33100	Main Steam Piping	0	0.16	0	0.00	0	0.00	0	0.00	0	0.00	0.16	0.70
33600	High Pressure Steam Piping	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
38000	Sulphur Oxides Removal System	0	0.00	0	0.00	0	0.00	2	0.22	0	0.00	0.22	0.00
Steam Generation Facilities Total		**8**	**1.90**	**118**	**3.60**	**101**	**3.19**	**21**	**1.98**	**32**	**5.93**	**11.27**	**5.00**

Fossil - Natural Gas
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16
Steam Turbine



Steam Turbine ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

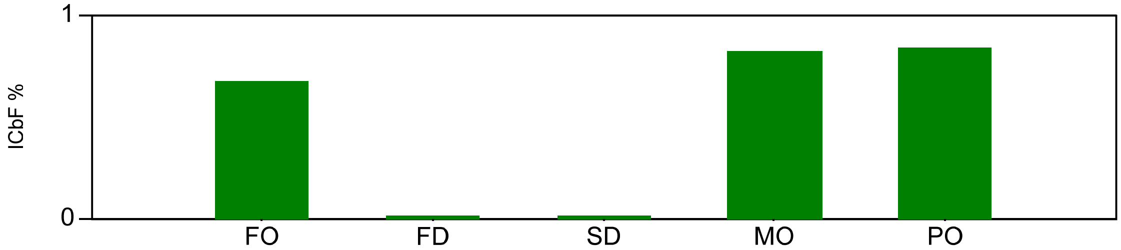
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Steam Turbine													
41100	Turbine	0	0.08	0	0.08	11	1.20	3	1.47	8	3.39	5.89	0.00
41120	Rotors	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41130	Blades	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
41150	Turning Gear	0	0.00	0	0.00	0	0.00	1	0.04	0	0.00	0.04	0.00
41160	Valve Gear	0	0.00	0	0.00	0	0.00	1	0.09	0	0.00	0.09	0.00
41170	Bearings And Pedestals	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
41200	Lubricating Oil System	1	0.03	0	0.00	0	0.00	3	0.07	0	0.00	0.10	0.13
41540	Gland Seal System-Water	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
41600	Turbovisory	2	0.28	0	0.00	0	0.00	0	0.00	0	0.00	0.28	1.27
41700	Governing System	0	0.00	0	0.00	0	0.00	3	0.07	0	0.00	0.07	0.00
Steam Turbine Total		**5**	**0.39**	**2**	**0.08**	**11**	**1.20**	**12**	**1.75**	**8**	**3.39**	**6.48**	**1.41**

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16

Generators



Generators ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

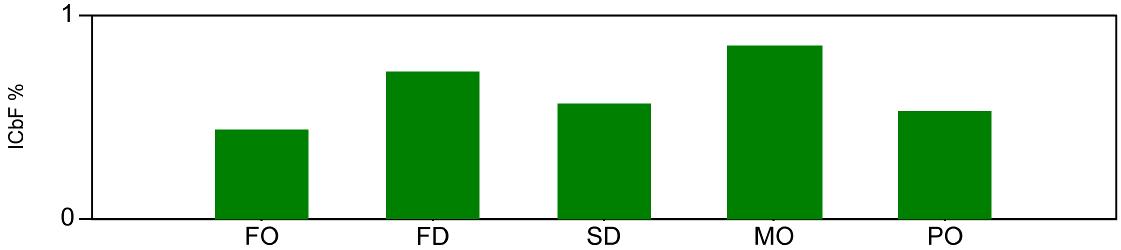
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Generators													
42100	Generator	1	0.00	1	0.00	0	0.00	1	0.01	4	0.60	0.61	0.01
42110	Generator Rotor	0	0.00	0	0.00	0	0.00	0	0.00	1	0.11	0.11	0.00
42111	Generator Bearings	2	0.67	0	0.00	0	0.00	2	0.15	0	0.00	0.82	2.99
42112	Generator Hydrogen Seals	0	0.00	0	0.00	0	0.00	0	0.00	1	0.11	0.11	0.00
42114	Generator Collector And Brushes	0	0.00	0	0.00	0	0.00	20	0.24	0	0.00	0.24	0.00
42200	Excitation Systems Equipment	3	0.00	0	0.00	0	0.00	8	0.31	8	0.01	0.32	0.01
42300	Hydrogen Gas Cooling System	0	0.00	0	0.00	0	0.00	2	0.01	0	0.00	0.01	0.00
42400	Generator Liquid Cooling System	0	0.00	0	0.00	0	0.00	2	0.07	0	0.00	0.07	0.00
42500	Seal Oil System	0	0.00	0	0.00	0	0.00	1	0.04	0	0.00	0.04	0.00
Generators Total		**6**	**0.67**	**1**	**0.00**	**0**	**0.00**	**36**	**0.83**	**14**	**0.83**	**2.33**	**3.01**

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16

Heat Power Cycle



Heat Power Cycle ICbF by event type for Fossil units based on 2005-2009 data.

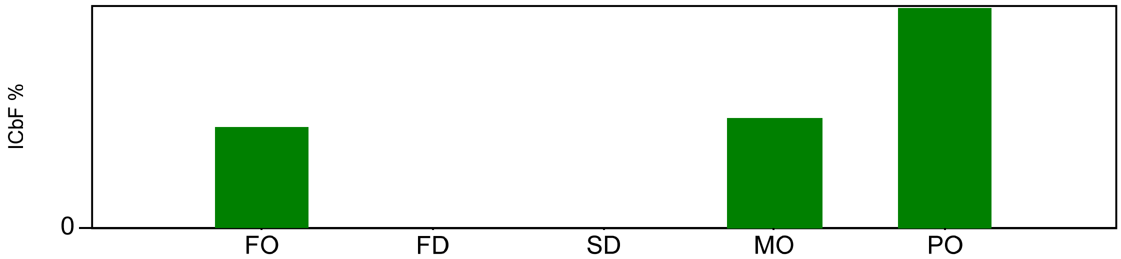
UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Heat Power Cycle													
43090	Boiler Feedwater Piping And Supports	1	0.00	0	0.00	0	0.00	3	0.07	0	0.00	0.08	0.01
43100	High Pressure Feedwater Heaters And	0	0.00	0	0.00	0	0.00	1	0.01	1	0.00	0.01	0.00
43200	Boiler Feed Pumps And Auxiliaries	2	0.03	6	0.14	0	0.03	5	0.11	0	0.03	0.23	0.15
43260	Boiler Feed Pump Variable Speed Coupling	0	0.02	4	0.06	1	0.02	0	0.02	0	0.02	0.07	0.06
43400	Boiler Feed Pump Motors And Auxiliaries	1	0.23	11	0.50	6	0.50	0	0.23	1	0.25	0.80	0.63
44110	Condensor	1	0.01	0	0.00	0	0.00	6	0.13	3	0.22	0.36	0.02
44120	Condensor Tubes	1	0.15	2	0.02	0	0.01	4	0.16	0	0.01	0.31	0.68
44500	Deaerator, Storage Tank, And Auxiliaries	0	0.00	0	0.00	0	0.00	1	0.02	0	0.00	0.02	0.00
45000	Air Extraction System	0	0.00	1	0.00	0	0.00	2	0.09	0	0.00	0.09	0.00
45100	Air Extraction System Vacuum Pumps	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
45300	Steam Air Ejectors	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
48400	Feedwater Heater Relief Valve, Vent	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
48500	Turbine And Piping Drains	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
Heat Power Cycle Total		**8**	**0.44**	**24**	**0.72**	**7**	**0.56**	**25**	**0.85**	**5**	**0.53**	**1.98**	**1.55**

Fossil - Natural Gas
Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16
Electrical Power Sys.



Electrical Power System ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

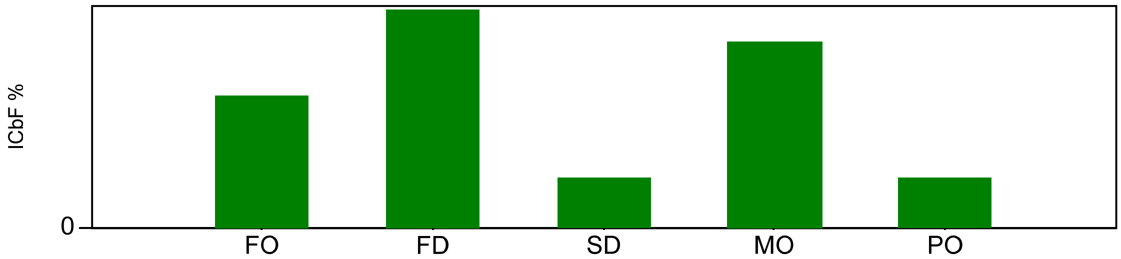
CODE	CAUSE	Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
		NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Electrical Power System													
51100	Output System Generator Voltage Equipment	1	0.00	0	0.00	0	0.00	0	0.00	1	0.01	0.01	0.00
51120	Generator Power Transformers	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
51133	Circuit Breakers-Generator Voltage	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51136	Disconnect Switches-Generator Voltage	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
51150	Bus Duct, Bus, Cable	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
53200	Station Service Power Distribution	2	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.02
Electrical Power System Total		**5**	**0.00**	**0**	**0.00**	**0**	**0.00**	**3**	**0.00**	**1**	**0.01**	**0.01**	**0.02**

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16

Ins. and Control



Instrumentation and Control ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

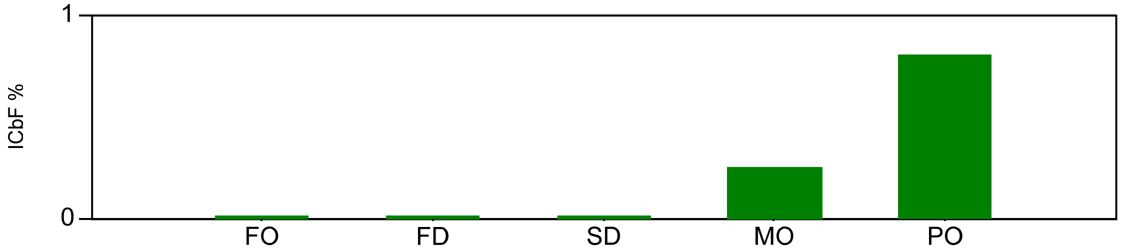
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Instrumentation and Control													
63100	Steam Generator Controls	1	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
63200	Equipment Controls-Furnace Draft	1	0.00	2	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
63300	Primary Steam Instrumentation & Control	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
63900	Ignition Fuel,Fuel Gas, & Miscellaneous	2	0.01	2	0.00	0	0.00	0	0.00	0	0.00	0.01	0.04
64100	Steam Turbine And Auxiliaries -	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
64200	Generator And Auxiliaries - Instrumentation and Control	8	0.02	0	0.00	0	0.00	3	0.04	0	0.00	0.06	0.09
64300	Boiler Feedwater System -Instrumentation and Control	3	0.02	7	0.06	0	0.01	0	0.01	0	0.01	0.06	0.08
64400	Condensate System - Instrumentation and Control	0	0.01	1	0.02	0	0.01	0	0.01	0	0.01	0.02	0.03
65100	Main Power Output Systems - Control and Protection	3	0.00	0	0.00	0	0.00	3	0.01	0	0.00	0.02	0.02
65300	Alternating Current Power Distribution - Control and Protection	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0.01	0.00
Instrumentation and Control Total		**19**	**0.06**	**13**	**0.09**	**0**	**0.02**	**8**	**0.08**	**0**	**0.02**	**0.19**	**0.26**

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16

Auxiliary Processes



Plant Aux. Processes and Services ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

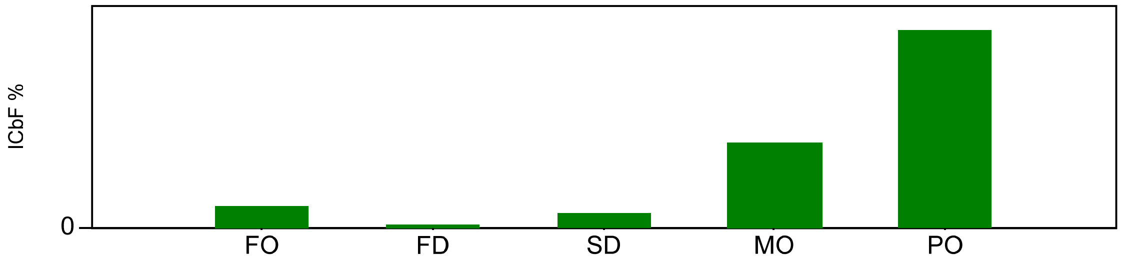
Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Plant Aux. Processes and Services													
71000	Circulating Water Systems	0	0.00	1	0.01	0	0.00	4	0.04	10	0.79	0.84	0.02
71140	Circulating Water Main Butterfly Valves and Operators	0	0.00	0	0.00	0	0.00	2	0.04	0	0.00	0.04	0.00
71190	Circulating Water Piping And Supports	0	0.00	0	0.00	0	0.00	3	0.04	1	0.01	0.05	0.00
73100	Auxiliary Steam And Condensate Systems	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
74000	Water Treatment Plant	0	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
76000	Miscellaneous Services	0	0.00	0	0.00	0	0.00	0	0.12	0	0.00	0.12	0.00
Plant Aux. Processes and Services Total		**0**	**0.00**	**3**	**0.01**	**0**	**0.00**	**10**	**0.24**	**11**	**0.80**	**1.05**	**0.03**

Fossil - Natural Gas

Detail Component Outage Code Report, 2005 to 2009

Table 6.2.16
Conditions



Conditions ICbF by event type for Fossil units based on 2005-2009 data.

UNIT STATISTICS

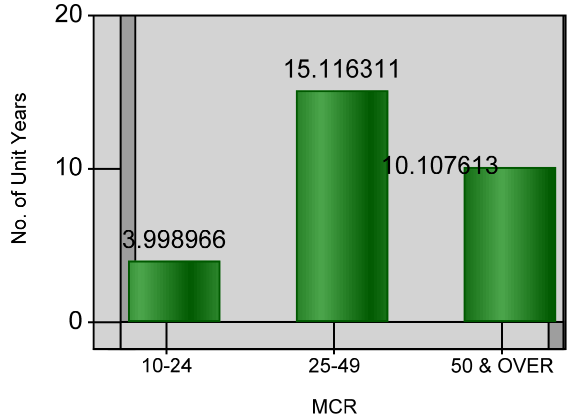
Number of Units:	16.00
Number of Unit Years:	61.67
Overall Operating Factor:	20.17

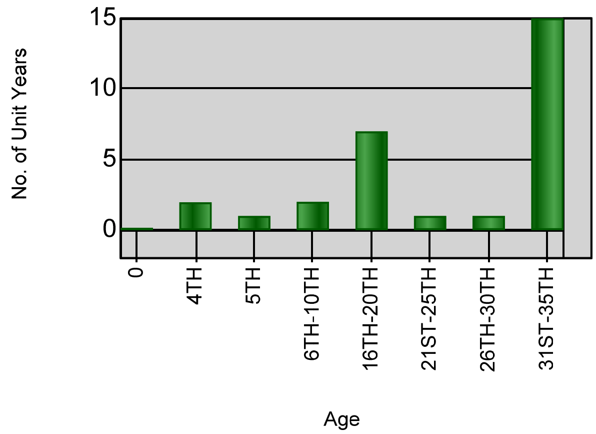
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
00500	Regulatory Bodies	0	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
04200	Synchronous Condenser Operation	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.01
05200	Transmission Limitations	2	0.02	0	0.00	6	0.01	10	0.03	16	0.14	0.21	0.07
99999	Other	1	0.00	0	0.00	0	0.00	5	0.04	1	0.03	0.07	0.00
Conditions Total		**4**	**0.02**	**0**	**0.00**	**6**	**0.01**	**16**	**0.07**	**17**	**0.17**	**0.28**	**0.08**

6.3 Combustion Turbine Summary Statistics

Combustion Turbine Units — Table 6.3.1

External Causes Excluded , 2009 Data

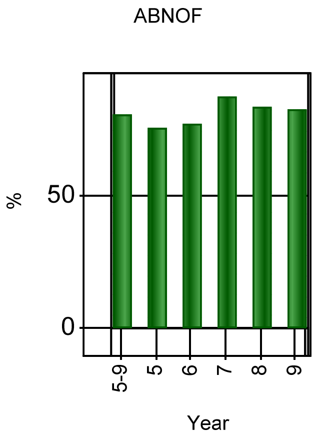


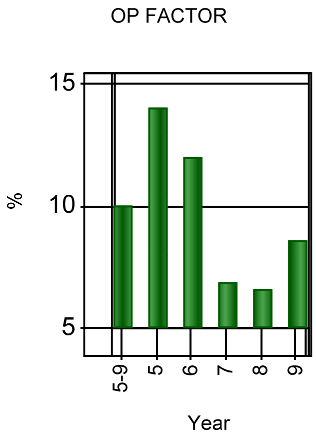


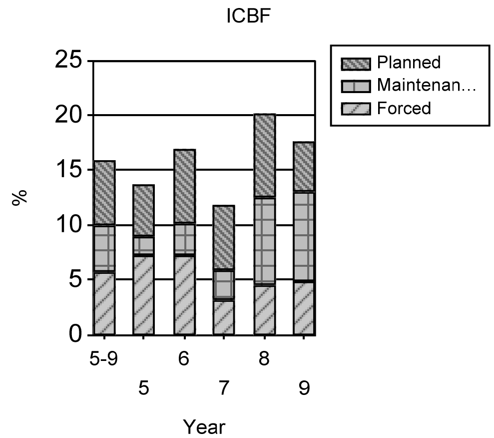
	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	UFOP (%)	DAUFOP (%)	SR	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
10-24	4.00	92.65	0.91	0.03	4	0.0	172.17	99.18	97.73	80.68	80.67	1.00	7.30	1900.22	3.68	2.49
25-49	15.12	72.25	13.31	15.13	102	0.4	1108.95	30.89	13.53	12.82	16.98	0.99	13.15	23.09	8.25	1.65
50 & OVER	10.11	93.54	11.14	2.15	29	0.1	607.88	45.15	40.35	39.42	40.26	0.97	11.28	22.93	1.26	1.41
Classification By Year Of Service																
0	0.2	92.97	0.03	6.42	5	0.0	4.70	1.81	8.64	8.05	8.05	0.85	0.61	0.00	0.00	0.00
4TH	2.0	13.51	0.00	77.26	27	0.1	378.43	20.88	4.00	3.96	10.65	1.00	13.02	11.00	1.08	3.33
5TH	1.0	38.28	0.00	47.14	15	0.1	1108.95	77.23	21.91	21.44	21.57	1.00	14.66	23.34	0.08	1.28
6TH-10TH	2.0	88.77	0.00	0.91	8	0.0	195.17	50.04	70.98	66	66	0.85	10.30	107.03	4.05	3.96
16TH-20TH	7.0	98.40	7.79	0.25	4	0.0	30.28	12.42	23.58	23.58	23.58	0.98	1.22	56.93	0.28	0.85
21ST-25TH	1.0	86.94	86.76	10.01	10	0.0	156.98	21.71	19.55	17.23	17.23	0.96	2.86	19.98	0.38	0.00
26TH-30TH	1.0	95.44	39.45	1.19	12	0.0	19.67	3.36	23.74	23.74	36.36	0.98	20.58	168.24	2.41	0.00
31ST-35TH	15.1	84.88	9.09	2.24	54	0.3	607.88	44.79	44.91	33.38	33.75	0.99	16.50	73.85	9.09	1.82
Classification By Operating Factor																
0-10	25.3	89.39	12.58	1.52	92	0.3	607.88	32.50	46.75	36.17	36.88	0.97	11.88	83.04	5.94	1.64
11-20	1.0	87.17	0.00	11.17	1	0.0	145.00	145.00	12.90	12.90	12.90	1.00	1.66	0.00	0.00	0.00
41-50	1.0	38.28	0.00	47.14	15	0.1	1108.95	77.23	21.91	21.44	21.57	1.00	14.66	23.34	0.08	1.28
61-70	1.0	26.92	0.00	64.57	15	0.1	378.43	29.80	7.32	7.24	8.68	1.00	6.32	9.29	0.20	0.02
81-90	1.0	0.09	0.00	89.95	12	0.0	43.67	9.73	1.46	1.46	12.16	1.00	19.71	12.23	1.96	6.63
All Units	29.2	82.39	10.86	8.58	135	0.6	1,108.95	35.98	18.03	16.95	20.67	0.98	11.70	23.86	5.21	1.68

Combustion Turbine Units — Table 6.3.2

External Causes Excluded, 2005 to 2009 Data





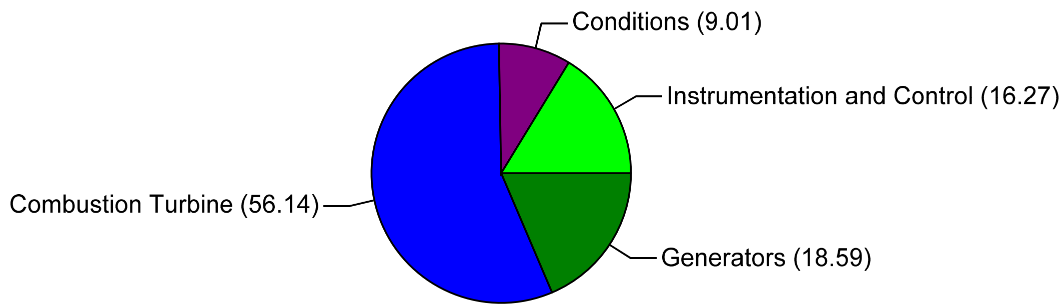


	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	UFOP (%)	DAUFOP (%)	SR	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
10-24	22.0	88.09	2.53	0.20	22	2.0	4150.36	779.66	97.79	86.57	86.57	0.99	11.66	250.97	1.19	1.57
25-49	75.5	79.09	18.39	11.93	450	1.9	8016.01	37.63	17.53	16.63	17.87	0.99	8.82	24.94	3.63	2.31
50 & OVER	68.1	80.17	16.48	11.14	209	1.1	2327.08	44.27	12.18	11.94	13.21	0.97	13.47	6.04	0.85	5.99
Classification By Year Of Service																
0	2.2	34.64	0.00	60.14	43	0.0	107.95	7.18	2.64	2.62	3.47	0.99	5.64	17.70	0.56	2.91
1ST	3.0	51.32	0.00	45.24	37	0.0	36.56	3.41	1.05	1.04	1.18	1.00	3.21	21.35	0.54	1.79
2ND	3.0	47.22	0.00	49.57	34	0.0	28.36	3.93	1.01	1	1.33	1.00	2.78	17.44	0.83	0.93
3RD	4.9	62.67	0.00	33.19	55	0.1	154.00	8.88	3.24	1.72	2.23	1.00	6.82	19.86	0.71	1.02
4TH	4.9	55.86	0.00	37.47	56	0.1	378.43	12.24	4.01	3.89	9.42	0.99	7.55	15.47	0.79	3.03
5TH	3.0	71.76	0.00	17.09	28	0.2	1108.95	65.85	29.10	22.55	22.69	0.99	10.53	29.25	0.10	3.38
6TH-10TH	6.0	88.59	0.00	3.33	16	0.1	230.00	66.41	37.62	22.34	22.34	0.95	8.05	9.95	2.23	3.80
11TH-15TH	26.0	94.17	7.38	0.86	39	0.2	355.95	40.96	44.68	39.21	39.21	0.97	4.95	17.81	1.57	2.68
16TH-20TH	10.0	97.13	5.43	1.30	9	0.0	31.47	11.58	8.29	7.45	7.45	0.99	1.48	22.94	0.44	0.91
21ST-25TH	10.0	71.92	50.71	10.11	39	1.3	6496.50	301.37	56.74	53.12	53.15	0.97	18.51	9.87	0.22	4.14
26TH-30TH	56.5	77.47	23.96	11.43	205	3.2	8016.01	137.17	33.16	20.14	21.45	0.97	14.85	10.37	0.71	4.55
31ST-35TH	37.2	85.67	12.50	1.33	121	0.4	607.88	29.86	45.23	31.51	31.96	0.98	15.23	84.19	6.57	4.64
Classification By Operating Factor																
0-10	139.7	88.45	14.22	1.65	450	5.2	8016.01	101.28	69.27	62.30	64.11	0.97	11.61	52.74	2.49	3.34
11-20	6.0	70.58	12.56	18.28	13	0.2	789.73	138.59	15.79	13.85	13.85	0.93	11.04	7.29	0.25	7.35
21-30	5.0	64.44	0.00	30.14	76	0.1	1108.95	17.25	8.96	8.73	8.88	1.00	5.12	31.18	0.50	1.38
31-40	4.9	58.48	0.00	36.97	101	0.1	378.43	6.51	3.90	3.85	4.41	1.00	3.93	35.76	0.51	1.49
81-90	4.0	0.52	80.73	83.51	1	0.0	0.80	0.80	0.01	0.00	0.00	1.00	15.96	0.30	0.01	15.95
91-100	7.0	0.14	26.31	94.46	41	0.1	107.95	11.99	0.84	0.84	2.65	0.99	16.82	5.90	0.63	3.93
All Units	**166.6**	**80.39**	**15.41**	**10.00**	**682**	**5.7**	**8,016.01**	**73.07**	**25.34**	**23.91**	**25.03**	**0.99**	**11.49**	**16.92**	**2.15**	**3.70**

Combustion Turbine Units — Table 6.3.3

Major Component Outage Code Report, 2005 to 2009

Major Componenent Contribution to Combustion Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	47.00
Number of Unit Yars:	177.19
Overall Operating Factor:	10.00

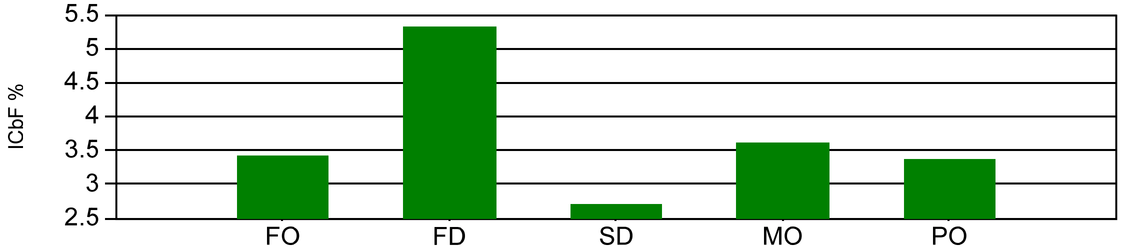
	FORCED OUTAGES		FORCED DERATINGS		SCHEDULED DERATINGS		MAINTENANCE OUTAGES		PLANNED OUTAGES		CONTRIBUTION TO UNIT		
MAJOR COMPONENT	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	FOR (%)	DAFOR (%)
Combustion Turbine	342	3.42	803	5.34	30	2.69	217	3.62	221	3.34	11.13	11.91	19.83
Conditions	68	0.09	29	0.14	1	0.06	28	0.23	33	0.15	0.44	0.29	0.65
Generators	107	1.25	10	0.15	4	0.05	56	0.33	104	1.73	3.31	8.94	8.33
Instrumentation and Control	130	0.57	12	0.04	1	0.00	58	0.10	30	0.48	1.18	4.31	3.89
TOTAL (External Causes Included)	647	5.33	854	5.67	36	2.80	359	4.28	388	5.70	16.06	25.45	32.70
TOTAL (External Causes Excluded)	595	5.32	826	5.55	35	2.78	331	4.06	360	5.61	15.72	25.39	32.32

Combustion Turbine Units

Detail Component Outage Code Report, 2005 to 2009 Data

Table 6.3.4

Combustion Turbine



Combustion Turbine ICbF by event type forCombustion units based on 2005-2009 data.

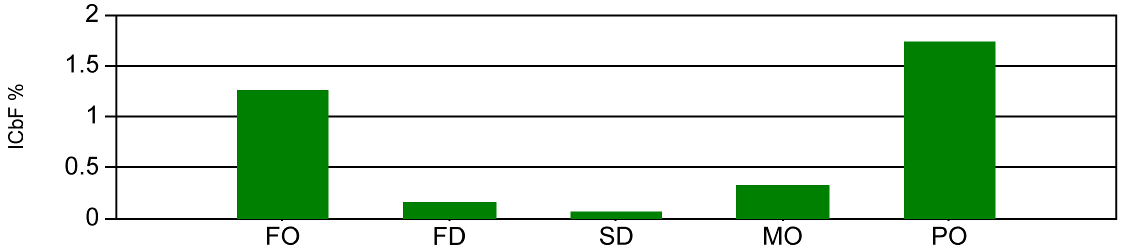
UNIT STATISTICS

Number of Units:	47.00
Number of Unit Yars:	177.19
Overall Operating Factor:	10.00

CODE	CAUSE	Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
		NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Combustion Turbine													
49100	Combustion Turbine	80	2.46	654	3.97	23	2.26	58	1.74	89	2.13	6.91	13.47
49101	Combustion Turbine - Exhaust Emission	8	0.03	14	0.09	3	0.02	2	0.02	2	0.15	0.25	0.18
49210	Compressor	5	0.00	0	0.00	0	0.00	25	1.20	12	0.03	1.23	0.01
49211	Compressor Shaft And Bearings For Tow-shaft Machine	21	0.00	0	0.00	0	0.00	1	0.00	1	0.00	0.00	0.01
49220	Combustion System	6	0.01	1	0.00	1	0.00	0	0.00	2	0.06	0.06	0.05
49221	Combustion Chamber	20	0.19	2	0.23	0	0.11	8	0.15	9	0.16	0.41	1.28
49230	Turbine(High Pressure If More Than One)	4	0.11	0	0.00	0	0.00	1	0.00	0	0.00	0.11	0.70
49231	Low Pressure Turbine	13	0.00	0	0.00	0	0.00	0	0.00	2	0.02	0.02	0.02
49232	Interstage Gas Passages	1	0.00	0	0.00	0	0.00	1	0.00	1	0.00	0.01	0.01
49240	Turbine Load Shaft And Bearing	4	0.01	0	0.00	0	0.00	2	0.00	0	0.00	0.01	0.05
49241	Reduction Gear	1	0.00	0	0.00	0	0.00	0	0.00	11	0.06	0.07	0.02
49242	Main Coupling	2	0.02	0	0.00	0	0.00	1	0.00	0	0.00	0.03	0.16
49243	Clutch	6	0.13	18	0.34	0	0.13	5	0.14	4	0.13	0.36	0.87
49251	Inlet Air Ducts And Vanes	8	0.04	15	0.25	0	0.04	4	0.04	5	0.15	0.37	0.26
49252	Air Filters	0	0.00	0	0.00	0	0.00	2	0.00	2	0.00	0.00	0.00
49253	Intercoolers	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
49260	Turning Gear System	6	0.02	0	0.00	0	0.00	2	0.00	2	0.00	0.02	0.12
49270	Starting System	38	0.03	2	0.00	0	0.00	5	0.01	23	0.12	0.15	0.17
49280	Battery And Charger System	2	0.00	0	0.00	0	0.00	6	0.01	2	0.00	0.01	0.01
49292	Exhaust Chamber Vanes	1	0.00	1	0.00	0	0.00	0	0.00	4	0.00	0.00	0.00
49293	Exhaust Stack And Silencer	4	0.01	2	0.00	0	0.00	7	0.05	11	0.16	0.22	0.07
49294	Exhaust Hood/Doors	4	0.00	0	0.00	0	0.00	3	0.01	1	0.00	0.01	0.00
49311	Internal Cooling And Seal Air System	5	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.03
49312	Heat Shields	0	0.00	0	0.00	0	0.00	1	0.00	1	0.00	0.00	0.00
49313	Supercharging Fan	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
49314	Fuel Supply System To Unit	27	0.08	46	0.14	1	0.03	21	0.06	9	0.06	0.23	0.51
49315	Unit Fuel Controls And Conditioning	16	0.06	10	0.14	1	0.05	4	0.05	6	0.05	0.16	0.37
49316	Ignition System	15	0.05	1	0.01	1	0.02	1	0.02	0	0.01	0.07	0.27
49317	Lubrication System	35	0.14	30	0.06	0	0.01	16	0.05	4	0.02	0.22	0.94
49318	Lubrication System - Power Turbine	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
49319	Cooling Water System	4	0.01	2	0.00	0	0.00	3	0.00	1	0.00	0.02	0.09
49321	External Cooling Air System	0	0.02	4	0.11	0	0.02	3	0.04	1	0.02	0.12	0.14
49322	Service Air Systems	1	0.00	0	0.00	0	0.00	27	0.03	0	0.00	0.04	0.02
49323	Building Heating	1	0.00	0	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
49324	Building Venting	0	0.00	1	0.00	0	0.00	2	0.00	0	0.00	0.00	0.00
49325	Building Fire Protection	1	0.00	0	0.00	0	0.00	3	0.00	16	0.01	0.02	0.00
Combustion Turbine Total		**342**	**3.42**	**803**	**5.34**	**30**	**2.69**	**217**	**3.62**	**221**	**3.34**	**11.13**	**19.83**

Combustion Turbine Units — Table 6.3.4

Detail Component Outage Code Report, 2005 to 2009 Data — Generator



Generators ICbF by event type forCombustion units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	47.00
Number of Unit Yars:	177.19
Overall Operating Factor:	10.00

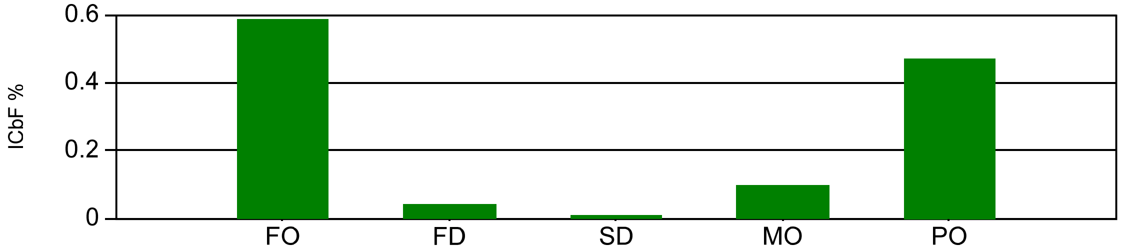
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Generators													
49800	Generator	21	0.09	1	0.03	2	0.01	18	0.14	54	1.07	1.30	0.62
49810	Generator Rotor	0	0.00	0	0.00	0	0.00	1	0.00	18	0.55	0.55	0.00
49811	Generator Bearings	19	0.08	7	0.11	0	0.04	1	0.11	0	0.04	0.21	0.53
49812	Generator Lubrication System	21	0.01	1	0.00	0	0.00	5	0.00	5	0.01	0.03	0.09
49813	Generator Collector And Brushes	0	0.00	0	0.00	0	0.00	8	0.01	0	0.00	0.01	0.00
49820	Generator Stator	3	0.55	0	0.00	0	0.00	2	0.02	1	0.00	0.57	3.63
49830	Generator Heaters	0	0.00	0	0.00	0	0.00	4	0.01	0	0.00	0.01	0.00
49840	Excitation System	15	0.07	0	0.00	2	0.00	1	0.00	3	0.00	0.07	0.44
49850	Synchronous Condensor Equipment	8	0.00	0	0.00	0	0.00	0	0.00	1	0.01	0.01	0.00
49860	Generator Output System	1	0.00	1	0.01	0	0.00	7	0.02	10	0.02	0.04	0.02
49870	Automatic Synchronizing Equipment	5	0.00	0	0.00	0	0.00	1	0.00	3	0.00	0.01	0.02
49880	Voltage Control Equipment	2	0.00	0	0.00	0	0.00	2	0.01	2	0.02	0.03	0.00
49890	Electrical Distribution System	12	0.45	0	0.00	0	0.00	6	0.01	7	0.01	0.47	2.98
Generators Total		**107**	**1.25**	**10**	**0.15**	**4**	**0.05**	**56**	**0.33**	**104**	**1.73**	**3.31**	**8.33**

Combustion Turbine Units

Detail Component Outage Code Report, 2005 to 2009 Data

Table 6.3.4

Ins. And Control



Instrumentation and Control ICbF by event type forCombustion units based on 2005-2009 data.

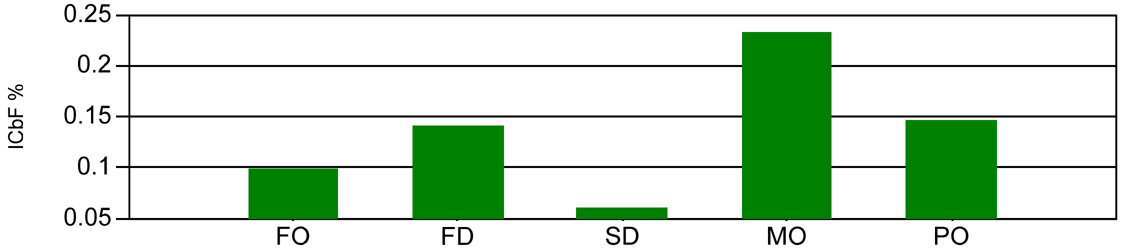
UNIT STATISTICS

Number of Units:	47.00
Number of Unit Yars:	177.19
Overall Operating Factor:	10.00

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Instrumentation and Control													
49900	Controls And Instrumentation-General	36	0.17	2	0.00	0	0.00	35	0.04	15	0.01	0.22	1.13
49910	Governing Systems	2	0.00	0	0.00	0	0.00	0	0.00	1	0.04	0.04	0.00
49920	Combustion Turbine Controls And	60	0.07	8	0.02	0	0.00	6	0.01	2	0.01	0.10	0.49
49940	Generator Controls And Instrumentation	10	0.00	0	0.00	1	0.00	6	0.00	1	0.00	0.01	0.03
49945	Supervisory Control & Data Acquisition -	1	0.00	0	0.00	0	0.00	1	0.00	0	0.00	0.00	0.00
49950	Fuel Management Controls And	10	0.01	2	0.02	0	0.00	1	0.00	6	0.01	0.03	0.06
49970	Main Power Output Systems -	5	0.16	0	0.00	0	0.00	4	0.00	1	0.00	0.16	1.07
49980	Auxiliaries Controls And Instrumentation	4	0.00	0	0.00	0	0.00	5	0.05	3	0.36	0.41	0.02
64210	Supervisory Control & Data Acquisition -	2	0.16	0	0.00	0	0.00	0	0.00	1	0.05	0.21	1.09
Instrumentation and Control Total		**130**	**0.57**	**12**	**0.04**	**1**	**0.00**	**58**	**0.10**	**30**	**0.48**	**1.18**	**3.89**

Combustion Turbine Units
Detail Component Outage Code Report, 2005 to 2009 Data

Table 6.3.4
Conditions



Conditions ICbF by event type forCombustion units based on 2005-2009 data.

UNIT STATISTICS

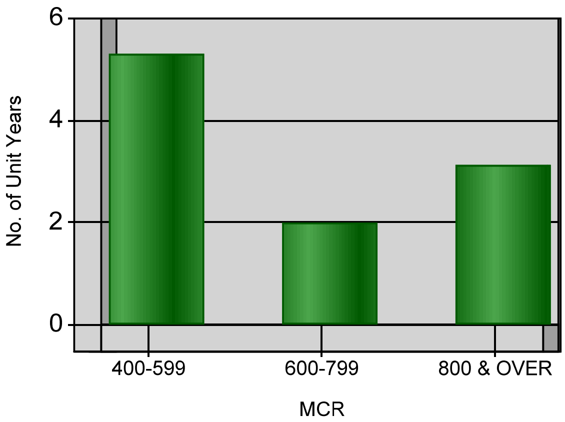
Number of Units:	47.00
Number of Unit Yars:	177.19
Overall Operating Factor:	10.00

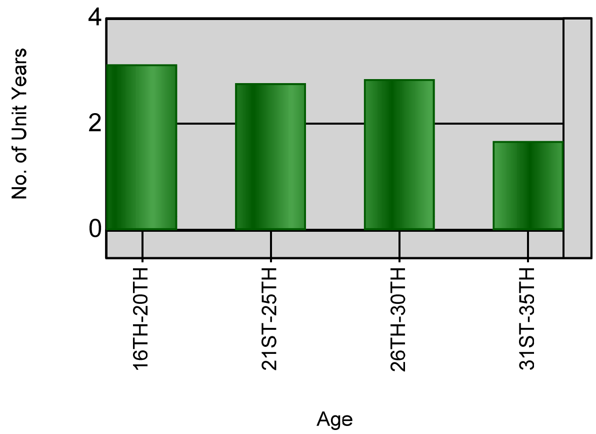
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Conditions													
01420	Problems - Primary Fuel for Units with Secondary Fuel Op.	2	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
05200	Transmission Limitations	11	0.00	3	0.00	0	0.00	10	0.01	13	0.01	0.02	0.02
05201	Powerhouse substation (none-generating Equipment)	15	0.02	0	0.00	0	0.00	0	0.00	3	0.01	0.02	0.11
05203	Transmission Equipment (Beyon transmission line)	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01	0.01	0.00
07010	Site Environment, Storms, Floods	7	0.00	2	0.00	0	0.00	2	0.00	2	0.01	0.02	0.03
07110	Nitrous Oxides	1	0.00	2	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
07210	Cooling Water Discharge-Thermal Effects	2	0.00	0	0.00	0	0.00	0	0.00	1	0.00	0.00	0.00
07510	Noise, Noise Complaints	0	0.00	0	0.00	0	0.00	0	0.00	1	0.00	0.00	0.00
08160	Fire, General	4	0.00	0	0.00	0	0.00	3	0.00	2	0.00	0.00	0.01
99999	Other	26	0.07	22	0.14	1	0.06	13	0.22	9	0.11	0.37	0.48
Conditions Total		**68**	**0.09**	**29**	**0.14**	**1**	**0.06**	**28**	**0.23**	**33**	**0.15**	**0.44**	**0.65**

6.4 Nuclear Summary Statistics

Nuclear Units — Table 6.4.1

External Causes Excluded, 2009 Data



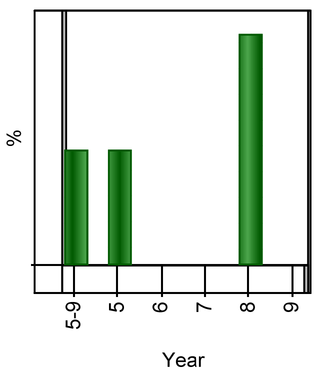


	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
400-599	5.3	0.00	0.00	70.27	13	0.5	779.87	369.02	10.04	14.18	14.18	1.3	22.32	2.24	0.00	9.11
600-799	2.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	2.0	100.00	0.00	0.00	100.00
800 & OVER	3.1	0.00	0.00	64.70	6	0.1	184.22	110.50	2.14	2.67	2.67	0.6	14.18	0.87	0.00	11.66
Classification By Year Of Service																
16TH-20TH	3.1	0.00	0.00	64.70	6	0.1	184.22	110.50	2.14	2.67	2.67	0.6	14.18	0.87	0.00	11.66
21ST-25TH	2.8	0.00	0.00	84.09	4	0.1	268.20	145.52	2.36	5.53	5.53	0.3	11.61	1.46	0.00	6.22
26TH-30TH	2.9	0.00	0.00	20.29	2	0.1	664.78	376.53	10.20	14.58	14.58	2.3	76.20	1.32	0.00	71.90
31ST-35TH	1.7	0.00	0.00	54.26	7	0.4	779.87	494.58	21.99	27.53	27.53	0.7	35.24	4.28	0.00	10.14
Classification By Operating Factor																
0-10	2.0	0.00	0.00	0.00	0	0.0	0.00	0.00	0.00	0.00	0.00	2.0	100.00	0.00	0.00	100.00
21-30	0.9	0.00	0.00	30.68	6	0.4	779.87	523.10	44.94	52.76	52.76	0.6	62.95	11.39	0.00	20.27
51-60	1.5	0.00	0.00	58.75	4	0.1	664.78	232.88	6.03	8.22	8.22	0.4	19.43	1.21	0.00	11.78
61-70	2.5	0.00	0.00	67.39	4	0.1	184.22	121.13	3.26	2.76	2.76	0.5	15.48	0.78	0.00	12.93
71-80	1.8	0.00	0.00	76.20	2	0.0	323.45	198.38	2.50	5.59	5.59	0.3	14.76	1.13	0.00	9.34
81-90	0.9	0.00	0.00	85.33	2	0.0	183.60	120.30	2.75	7.44	7.44	0.1	7.44	2.06	0.00	0.00
91-100	1.0	0.00	0.00	92.37	1	0.0	268.20	268.20	3.06	5.40	5.40	0.1	5.40	1.03	0.00	0.00
All Units	**10.4**	**0.00**	**0.00**	**56.70**	**19**	**0.6**	**779.87**	**287.38**	**6.94**	**9.65**	**9.65**	**3.9**	**32.55**	**1.67**	**0.00**	**25.11**

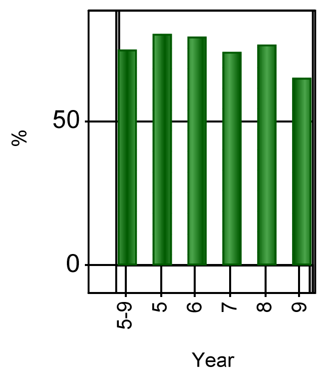
Nuclear Units — Table 6.4.2

Major Component Outage Code Report, 2005 - 2009

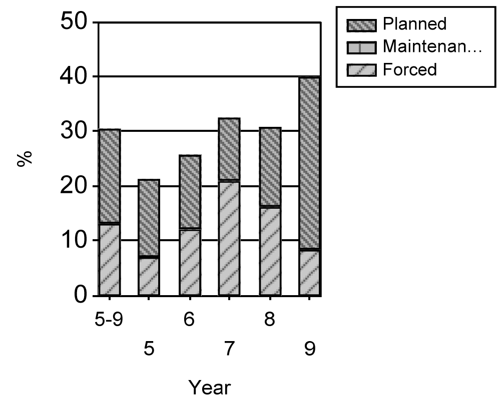
ABNOF



OP FACTOR



ICBF

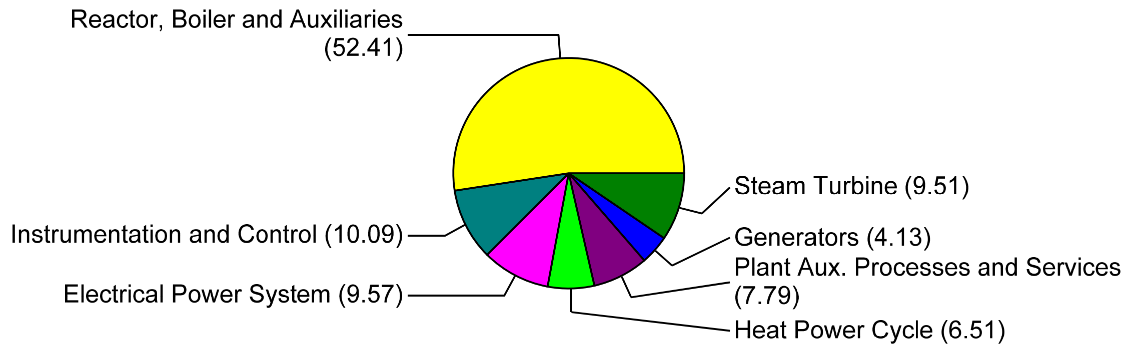


	Unit years (A)	ABNOF (%)	SynCD Factor (%)	OP Factor (%)	No. Forced Outages	Total F.O.T. (A)	Maximum F.O.D. (H)	Mean F.O.D. (H)	FOR (%)	DAFOR (%)	DAUFOP (%)	Total EQ. Out. Time (A)	ICBF (%)	Fail Rate	MOF (%)	POF (%)
Classification By MCR (MW)																
400-599	25.9	0.00	0.00	64.68	87	4.7	5700.87	470.76	17.48	20.58	20.58	8.0	27.40	3.04	0.00	8.20
600-799	8.0	0.01	0.00	58.50	9	0.1	246.58	99.78	2.14	2.45	2.45	3.6	45.45	1.49	0.00	40.21
800 & OVER	15.4	0.01	0.00	67.10	29	0.4	544.91	109.42	1.97	2.33	2.33	2.0	10.19	1.22	0.00	7.91
Classification By Year Of Service																
11TH-15TH	9.0	0.02	0.00	66.57	20	0.3	544.91	120.34	2.44	2.82	2.22	1.1	9.13	1.46	0.00	6.36
16TH-20TH	8.8	0.00	0.00	68.66	16	0.2	782.85	125.90	2.31	2.89	2.69	1.4	12.31	1.13	0.00	9.56
21ST-25TH	20.2	0.00	0.00	69.91	49	2.0	5700.87	360.54	10.51	12.64	12.6	5.6	25.43	2.04	0.00	12.79
26TH-30TH	7.7	0.00	0.00	42.85	20	1.8	5026.83	794.74	31.39	34.22	34.22	4.4	53.49	4.03	0.00	28.99
31ST-35TH	3.5	0.00	0.00	63.44	20	0.8	1418.63	352.22	21.15	27.45	27.45	1.3	31.52	6.00	0.00	5.06
Classification By Operating Factor																
41-50	6.0	0.00	0.00	49.70	6	0.1	246.58	130.44	2.91	3.39	3.39	3.3	55.59	1.34	0.00	48.81
51-60	11.7	0.00	0.00	55.24	44	2.0	2917.63	390.22	14.50	17.19	17.19	3.9	25.74	3.12	0.00	9.91
61-70	15.9	0.01	0.00	67.86	45	1.7	5026.83	333.69	9.55	11.60	11.60	3.3	17.21	2.15	0.00	6.18
71-80	13.7	0.00	0.00	73.29	27	1.4	5700.87	442.36	9.95	11.15	11.15	2.9	19.11	1.46	0.00	8.68
81-90	2.0	0.05	0.00	84.93	3	0.0	60.11	38.47	0.77	0.77	0.77	0.3	15.02	1.77	0.00	14.36
All Units	**49.3**	**0.01**	**0.00**	**64.66**	**125**	**5.1**	**5,700.87**	**360.22**	**10.29**	**12.11**	**12.11**	**13.7**	**23.90**	**2.14**	**0.00**	**12.58**

Nuclear Units — Table 6.4.3

Major Component Outage Code Report, 2005 - 2009

Major Componenent Contribution to Nuclear Unit ICbF based on 2005-2009 data.



UNIT STATISTICS

Number of Units:	14.00
Number of Unit Yars:	61.18
Overall Operating Factor:	78.39

	FORCED OUTAGES		FORCED DERATINGS		SCHEDULED DERATINGS		MAINTENANCE OUTAGES		PLANNED OUTAGES		CONTRIBUTION TO UNIT		
MAJOR COMPONENT	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	FOR (%)	DAFOR (%)
Conditions	0	0.51	805	14.22	1	0.51	0	0.51	0	0.51	14.22	0.00	0.57
Electrical Power System	12	3.40	42	0.38	0	0.06	0	0.06	2	0.50	4.15	3.81	3.89
Generators	7	0.20	32	0.39	0	0.09	0	0.09	0	0.09	0.51	0.13	0.23
Heat Power Cycle	11	0.61	459	6.00	4	0.36	0	0.30	0	0.30	6.38	0.36	0.70
Instrumentation and Control	16	0.84	1386	6.84	15	0.41	0	0.39	0	0.51	7.43	0.52	0.97
Plant Aux. Processes and Services	12	0.98	151	1.27	15	0.34	0	0.16	0	0.16	2.28	0.93	1.10
Reactor, Boiler and Auxiliaries	53	4.72	322	4.32	134	6.52	0	1.13	29	12.87	25.06	4.11	4.64
Steam Turbine	13	0.55	115	1.48	34	0.45	0	0.19	3	0.46	2.36	0.41	0.59
TOTAL (External Causes Included)	124	11.81	3312	34.90	203	8.74	0	2.83	34	15.40	62.39	10.27	12.69
TOTAL (External Causes Excluded)	124	13.13	2510	23.99	203	9.54	0	0.00	36	17.29	55.84	12.21	14.37

Nuclear Units — Table 6.4.4

Detail Component Outage Code Report, 2005 to 2009 — Building and Structures

Buildings and Structures ICbF by event type forNuclear units based on 2005-2009 data.

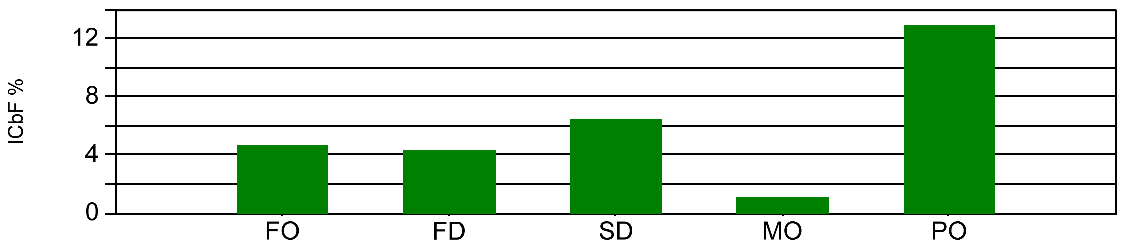
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Buildings and Structures													
Buildings and Structures Total													

Nuclear Units
Table 6.4.4
Detail Component Outage Code Report, 2005 to 2009

Reactor, Boiler and Aux.



Reactor, Boiler and Auxiliaries ICbF by event type forNuclear units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

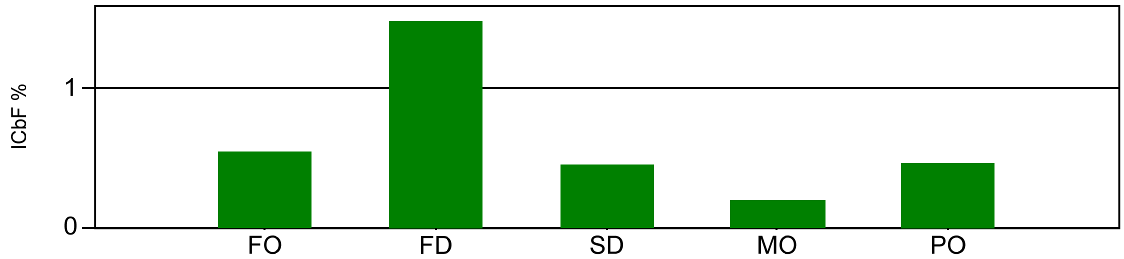
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Reactor, Boiler and Auxiliaries													
31000	Reactor	0	0.00	0	0.00	0	0.00	0	0.00	3	5.14	5.14	0.00
31100	Reactor Fuel Channel Assemblies	1	0.10	1	0.07	28	0.23	0	0.06	9	3.19	3.41	0.05
31700	Reactor Reactivity Control Units	9	1.47	30	0.86	46	5.49	0	0.63	4	0.92	6.85	1.07
31800	Reactor Shut-Off Units	1	0.04	4	0.05	0	0.01	0	0.01	0	0.01	0.09	0.05
32100	Main Moderator System	2	0.05	5	0.03	0	0.00	0	0.00	0	0.00	0.08	0.06
32300	Moderator Level & Pressure Control	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0.03	0.03
33100	Main Heat Transport Circuit	13	1.03	28	0.20	14	0.17	0	0.06	4	1.14	2.36	1.14
33110	Main Heat Transport Circuit Steam	2	0.24	1	0.04	13	0.15	0	0.04	3	0.91	1.24	0.24
33120	Main Heat Transport Circuit Heat Transport Pumps	1	0.06	5	0.01	0	0.00	0	0.00	0	0.00	0.07	0.07
33300	Primary Heat Transport And Inventory Control Systems	3	0.12	29	0.38	6	0.06	0	0.03	1	0.11	0.57	0.13
33400	Primary Heat Transport Shut-Down Cooling Systems	9	0.57	10	0.12	4	0.03	0	0.03	1	0.06	0.70	0.66
33500	Primary Heat Transport Gas Control	0	0.00	1	0.02	0	0.00	0	0.00	0	0.00	0.02	0.00
33600	Primary Heat Transport Overpressure	1	0.04	0	0.00	2	0.01	0	0.00	0	0.00	0.05	0.04
33700	Primary Heat Transport Transfer System	1	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0.12	0.14
33800	Primary Heat Transport Heavy Water Collection Systems	1	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0.09	0.10
34300	Emergency Cooling Systems	1	0.03	6	0.02	0	0.00	0	0.00	0	0.00	0.05	0.04
35000	Fuel Handling	3	0.64	146	2.09	13	0.30	0	0.23	2	0.69	3.02	0.72
35200	Fueling Machine	2	0.05	13	0.07	0	0.01	0	0.01	1	0.29	0.39	0.06
35300	Irradiated Fuel Transfer And Storage	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
36000	Boiler Steam And Water Systems	1	0.03	37	0.29	7	0.05	0	0.02	0	0.02	0.32	0.03
36100	Steam System	0	0.00	1	0.00	1	0.00	0	0.00	0	0.00	0.01	0.00
36700	Steam Generator Emergency Cooling	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
37000	Fuel	0	0.01	4	0.07	0	0.01	0	0.01	1	0.39	0.45	0.01
Reactor, Boiler and Auxiliaries Total		**53**	**4.72**	**322**	**4.32**	**134**	**6.52**	**0**	**1.13**	**29**	**12.87**	**25.06**	**4.64**

Nuclear Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4

Steam Turbine



Steam Turbine ICbF by event type forNuclear units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

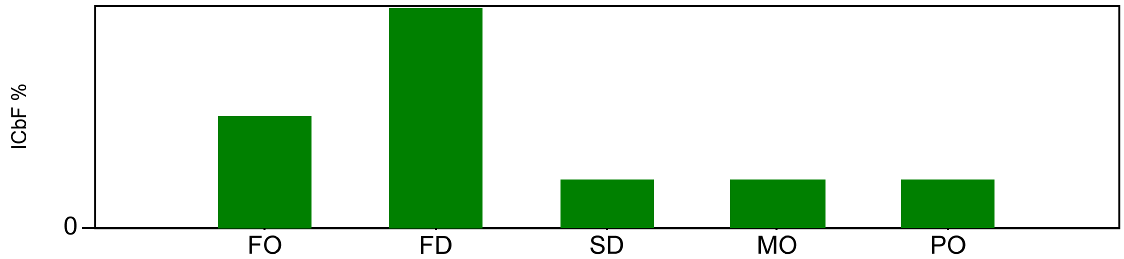
		Forced Outages		Forced Deratings		Scheduling Deratings		Maintenance Outages		Planned Outages		Contribution To Unit	
CODE	CAUSE	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	NO. OCC.	ICBF (%)	ICBF (%)	DAFOR (%)
Steam Turbine													
41100	Turbine	9	0.35	51	0.58	13	0.15	0	0.10	2	0.31	1.09	0.38
41700	Governing System	4	0.16	26	0.33	0	0.05	0	0.05	0	0.05	0.43	0.18
41810	Moisture Separator	0	0.00	4	0.05	4	0.04	0	0.00	0	0.00	0.09	0.00
41830	Steam Reheater	0	0.04	34	0.52	17	0.21	0	0.04	1	0.10	0.75	0.03
Steam Turbine Total		**13**	**0.55**	**115**	**1.48**	**34**	**0.45**	**0**	**0.19**	**3**	**0.46**	**2.36**	**0.59**

Nuclear Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4

Generator



Generators ICbF by event type forNuclear units based on 2005-2009 data.

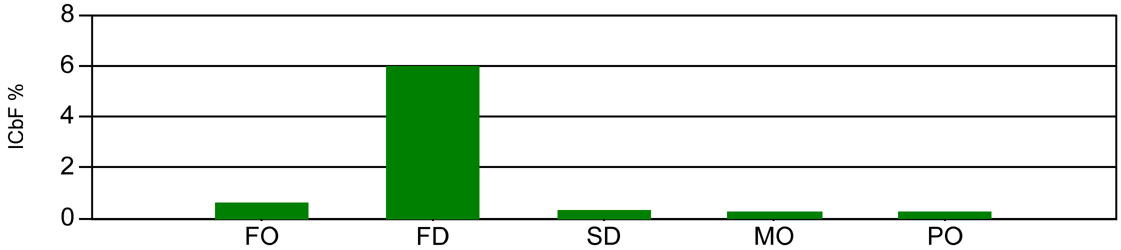
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Generators													
42100	Generator	4	0.09	14	0.06	0	0.02	0	0.02	0	0.02	0.14	0.10
42200	Excitation Systems Equipment	3	0.05	9	0.04	0	0.01	0	0.01	0	0.01	0.08	0.06
42400	Generator Liquid Cooling System	0	0.06	9	0.29	0	0.06	0	0.06	0	0.06	0.29	0.07
Generators Total		**7**	**0.20**	**32**	**0.39**	**0**	**0.09**	**0**	**0.09**	**0**	**0.09**	**0.51**	**0.23**

Nuclear Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4
Heat Power Cycle



Heat Power Cycle ICbF by event type forNuclear units based on 2005-2009 data.

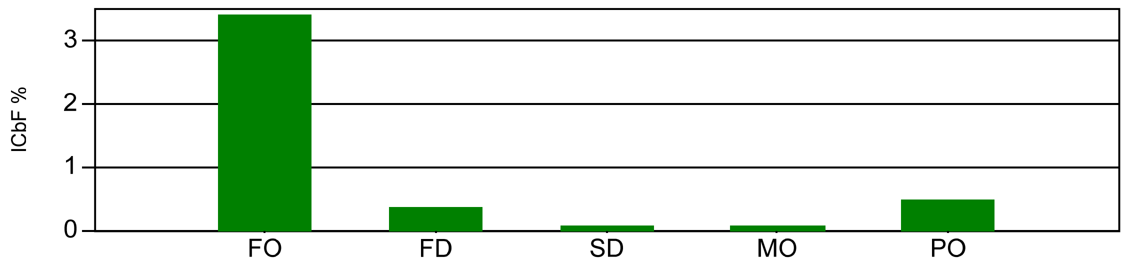
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Heat Power Cycle													
43100	High Pressure Feedwater Heaters And Auxiliaries	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
43200	Boiler Feed Pumps And Auxiliaries	8	0.36	42	0.57	1	0.08	0	0.08	0	0.08	0.85	0.42
43500	Auxiliary Boiler Feed Pump Motors And Auxiliaries	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
44030	Main Condensate Circuit	0	0.11	221	3.15	2	0.15	0	0.11	0	0.11	3.19	0.13
44110	Condensor	0	0.08	173	1.84	1	0.10	0	0.08	0	0.08	1.86	0.09
44120	Condensor Tubes	0	0.02	10	0.28	0	0.02	0	0.02	0	0.02	0.28	0.02
44200	Condensate Extraction Pumps And Auxiliaries	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
48100	Extraction Steam System	0	0.00	3	0.04	0	0.00	0	0.00	0	0.00	0.04	0.00
48200	Feedwater Heater Drains System	2	0.03	8	0.11	0	0.01	0	0.01	0	0.01	0.14	0.03
Heat Power Cycle Total		**11**	**0.61**	**459**	**6.00**	**4**	**0.36**	**0**	**0.30**	**0**	**0.30**	**6.38**	**0.70**

Nuclear Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4
Electrical Power System



Electrical Power System ICbF by event type forNuclear units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

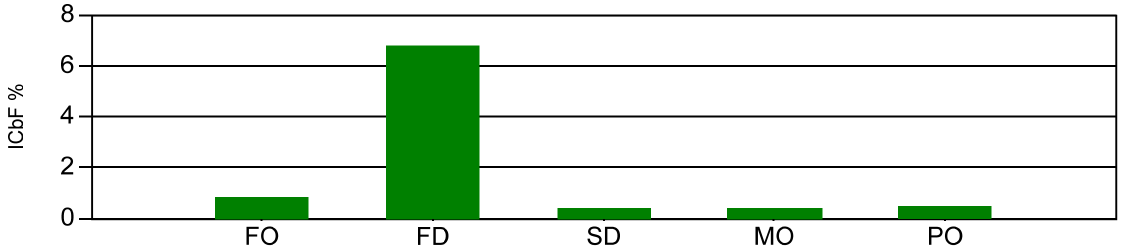
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Electrical Power System													
51100	Output System Generator Voltage Equipment	2	1.17	12	0.07	0	0.02	0	0.02	0	0.02	1.22	1.34
51120	Generator Power Transformers	3	0.20	9	0.06	0	0.01	0	0.01	0	0.01	0.25	0.23
51130	Switching Equipment-Generator Voltage	1	0.06	4	0.11	0	0.02	0	0.02	0	0.02	0.15	0.07
53200	Station Service Power Distribution	6	1.97	16	0.13	0	0.01	0	0.01	2	0.45	2.52	2.25
55000	Direct Current Power Supplies	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
Electrical Power System Total		**12**	**3.40**	**42**	**0.38**	**0**	**0.06**	**0**	**0.06**	**2**	**0.50**	**4.15**	**3.89**

Nuclear Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4

Instrumentation & Control



Instrumentation and Control ICbF by event type forNuclear units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

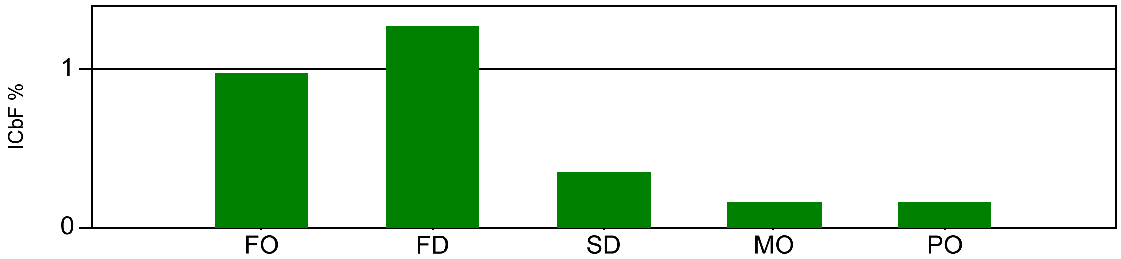
CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Instrumentation and Control													
63100	Reactor And Auxiliaries -Instrumentation and Control	2	0.20	378	2.49	12	0.16	0	0.15	0	0.15	2.55	0.23
63300	Heat Transport System - Instrumentation and Control	0	0.00	2	0.03	0	0.00	0	0.00	0	0.00	0.03	0.00
63700	Reactor Control Systems (Reactor Regulating Systems) Instrum. & Control	6	0.44	971	4.02	3	0.21	0	0.20	0	0.20	4.26	0.51
64100	Steam Turbine And Auxiliary - Instrumentation and Control	2	0.04	9	0.06	0	0.01	0	0.01	0	0.01	0.09	0.05
64200	Generator And Auxiliaries - Instrumentation and Control	1	0.03	3	0.03	0	0.01	0	0.01	0	0.01	0.05	0.03
64300	Boiler Feedwater Systems - Instrumentation and Control	0	0.01	9	0.16	0	0.01	0	0.01	0	0.01	0.16	0.01
64400	Condensate System - Instrumentation and Control	1	0.01	3	0.01	0	0.00	0	0.00	0	0.00	0.02	0.01
64700	Condensate Make-up System - Instrumentation and Control	0	0.00	1	0.00	0	0.00	0	0.00	0	0.00	0.00	0.00
65900	System Control Facilities	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.01
68000	Safety Systems Control	3	0.10	5	0.02	0	0.01	0	0.01	0	0.13	0.24	0.12
69000	Computers	0	0.00	5	0.02	0	0.00	0	0.00	0	0.00	0.02	0.00
Instrumentation and Control Total		**16**	**0.84**	**1386**	**6.84**	**15**	**0.41**	**0**	**0.39**	**0**	**0.51**	**7.43**	**0.97**

Nuclear Units

Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4

Plant Aux. Processes & Services



Plant Aux. Processes and Services ICbF by event type forNuclear units based on 2005-2009 data.

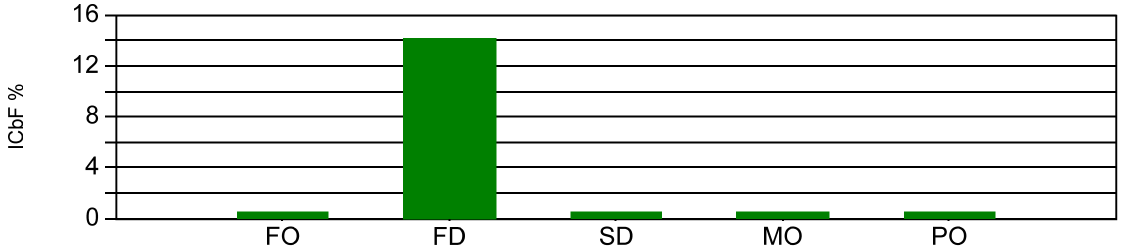
UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Plant Aux. Processes and Services													
71109	Circulating Water Piping	3	0.13	117	0.83	15	0.26	0	0.08	0	0.08	1.07	0.14
71110	Circulating Water Travelling H2O Screens	0	0.00	5	0.01	0	0.00	0	0.00	0	0.00	0.01	0.00
72100	Service water Low Pressure Open System	4	0.32	18	0.21	0	0.01	0	0.01	0	0.01	0.52	0.36
73700	Containment Atmosphere System Heating, Ventilationand Cooling Systems	2	0.13	8	0.06	0	0.01	0	0.01	0	0.01	0.18	0.14
74000	Water Treatment Plant	3	0.40	3	0.16	0	0.06	0	0.06	0	0.06	0.50	0.46
Plant Aux. Processes and Services Total		**12**	**0.98**	**151**	**1.27**	**15**	**0.34**	**0**	**0.16**	**0**	**0.16**	**2.28**	**1.10**

Nuclear Units
Detail Component Outage Code Report, 2005 to 2009

Table 6.4.4
Conditions



Conditions ICbF by event type forNuclear units based on 2005-2009 data.

UNIT STATISTICS

Number of Units:	14.00
Number of Unit Years:	61.18
Overall Operating Factor:	78.39

CODE	CAUSE	Forced Outages NO. OCC.	Forced Outages ICBF (%)	Forced Deratings NO. OCC.	Forced Deratings ICBF (%)	Scheduling Deratings NO. OCC.	Scheduling Deratings ICBF (%)	Maintenance Outages NO. OCC.	Maintenance Outages ICBF (%)	Planned Outages NO. OCC.	Planned Outages ICBF (%)	Contribution To Unit ICBF (%)	Contribution To Unit DAFOR (%)
Conditions													
05200	Transmission Limitations	0	0.03	56	0.17	0	0.03	0	0.03	0	0.03	0.17	0.03
07010	Site Environment, Storms, Floods	0	0.02	30	0.17	0	0.02	0	0.02	0	0.02	0.17	0.02
07210	Cooling Water Discharge Thermal Effects	0	0.26	447	8.12	0	0.26	0	0.26	0	0.26	8.12	0.30
99999	Other	0	0.20	272	5.76	1	0.20	0	0.20	0	0.20	5.76	0.22
Conditions Total		**0**	**0.51**	**805**	**14.22**	**1**	**0.51**	**0**	**0.51**	**0**	**0.51**	**14.22**	**0.57**

NOVA SCOTIA POWER INC.
REGULATED OPERATING, MAINTENANCE AND GENERAL EXPENSES
FOR THE YEARS 2009 THROUGH 2016

(in Thousands of $)

	2009 Compliance Restated	*2010 Actuals*	*2011 Forecast*	*2012 Forecast*	*2013 Forecast*		*2014 Forecast*		*2015 Forecast*		*2016 Forecast*	
Executive Management	1,941	1,152	[redacted]	1,254	1,288	2.7%	1,316	2.2%	1,321	0.4%	1,336	1.1%
Corporate Office of Secretary and General Counsel	6,761	7,052	[redacted]	8,485	9,073	6.9%	9,581	5.6%	10,068	5.1%	10,614	5.4%
Corporate Finance	4,804	5,918	[redacted]	5,684	5,866	3.2%	5,905	0.7%	5,733	-2.9%	5,736	0.1%
Investor Relations, Communications and Public Affairs	1,766	2,418	[redacted]	2,486	2,550	2.6%	2,607	2.2%	2,626	0.7%	2,661	1.4%
Corporate Human Resources (including Safety)	4,096	4,837	[redacted]	5,216	5,363	2.8%	5,482	2.2%	5,483	0.0%	5,534	0.9%
Facilities and Procurement	10,139	10,266	[redacted]	8,965	9,218	2.8%	9,424	2.2%	9,430	0.1%	9,521	1.0%
Information Technology	9,100	9,037	[redacted]	10,510	10,774	2.5%	11,012	2.2%	11,135	1.1%	11,310	1.6%
Regulatory Affairs	5,362	5,291	[redacted]	5,859	6,006	2.5%	6,139	2.2%	6,207	1.1%	6,304	1.6%
TOTAL CORPORATE GROUPS	**43,969**	**45,971**	[redacted]	**48,459**	**50,137**	**3.5%**	**51,466**	**2.6%**	**52,003**	**1.0%**	**53,017**	**1.9%**
TECHNICAL & CONSTRUCTION SERVICES	**9,363**	**11,694**	[redacted]	**13,524**	**13,831**	**2.3%**	**14,137**	**2.2%**	**14,013**	**-0.9%**	**14,091**	**0.6%**
SUSTAINABILITY	**1,229**	**3,348**	[redacted]	**1,973**	**2,025**	**2.6%**	**2,070**	**2.2%**	**2,081**	**0.6%**	**2,107**	**1.2%**
Renewable Planning	-	-	[redacted]	-	-	-	-	-	-		-	-
Head Office	10,831	10,875	[redacted]	16,915	17,466	3.3%	17,470	0.0%	15,315	-12.3%	13,988	-8.7%
Thermal Plants	62,318	65,306	[redacted]	66,671	68,493	2.7%	70,366	2.7%	72,290	2.7%	72,269	0.0%
Combustion Turbines	1,109	1,218	[redacted]	1,318	1,354	2.7%	1,390	2.7%	1,427	2.7%	1,465	2.7%
Hydro & Wind Energy	8,121	10,092	[redacted]	15,133	15,526	2.6%	18,324	18.0%	21,186	15.6%	21,719	2.5%
Energy, Fuels and Risk Management	3,269	3,408	[redacted]	3,825	3,930	2.7%	4,037	2.7%	4,148	2.7%	4,261	2.7%
TOTAL POWER PRODUCTION	**85,648**	**90,898**	[redacted]	**103,862**	**106,768**	**2.8%**	**111,587**	**4.5%**	**114,367**	**2.5%**	**113,703**	**-0.6%**
Regional Operations	15,305	22,366	[redacted]	12,992	13,358	2.8%	13,737	2.8%	14,127	2.8%	14,528	2.8%
Control Center	6,829	7,142	[redacted]	8,097	8,323	2.8%	8,556	2.8%	8,795	2.8%	9,041	2.8%
Reliability and Transmission & Workforce Management	24,924	33,554	[redacted]	31,005	31,582	1.9%	32,177	1.9%	32,788	1.9%	31,417	-4.2%
Administration (incl Storm)	16,918	9,474	[redacted]	21,152	21,861	3.4%	22,226	1.7%	21,193	-4.6%	19,716	-7.0%
TOTAL CUSTOMER OPERATIONS	**63,976**	**72,536**	[redacted]	**73,246**	**75,125**	**2.6%**	**76,695**	**2.1%**	**76,903**	**0.3%**	**74,703**	**-2.9%**
CUSTOMER SERVICE	**30,162**	**34,340**	[redacted]	**32,459**	**33,427**	**3.0%**	**34,192**	**2.3%**	**34,331**	**0.4%**	**34,641**	**0.9%**
CORPORATE ADJUSTMENTS	**(17,678)**	**(29,160)**	[redacted]	**(25,055)**	**(25,724)**	**2.7%**	**(29,571)**	**15.0%**	**(29,839)**	**0.9%**	**(16,725)**	**-43.9%**
TOTAL REGULATED OM&G	**216,669**	**229,627**	[redacted]	**248,468**	**255,588**	**2.9%**	**260,574**	**2.0%**	**263,859**	**1.3%**	**275,537**	**4.4%**

OPINION

ON

CAPITAL STRUCTURE

AND

RETURN ON EQUITY

FOR

NOVA SCOTIA POWER INC.

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

April 2011

TABLE OF CONTENTS

I. INTRODUCTION AND CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. 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 am a Chartered Financial Analyst (1989).

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

I have been requested by Nova Scotia Power Inc. (NSPI) to provide an expert opinion on the reasonableness of its 37.5% deemed common equity ratio and to recommend a fair ROE for the 2012 test year.

B. CONCLUSIONS

My principal conclusions are as follows:

(1) While global capital markets and economies have improved substantially since the height of the financial crisis, significant risks to the capital markets and economies remain. These include:

- (a) Sovereign debt concerns in several countries;
- (b) Financial fragility associated with the weak global economic recovery;
- (c) Global imbalances;
- (d) The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and

(e) High leverage of Canadian households.

(3) With respect to business risk, as a vertically integrated electric utility with significant electricity generation assets, NSPI faces higher business risk than the typical Canadian electric or gas utility, whose operations are focused largely in "wires" or "pipes".

(4) NSPI's 37.5% common equity ratio is lower than the Canadian utility sector averages, both allowed and actual. NSPI's higher business risk relative to its Canadian peers' has not been offset by lower financial risk, i.e., by a thicker common equity ratio.

(5) With both higher business risk and a lower common equity ratio than its Canadian peers', NSPI's total risk is higher than that of the average risk Canadian utility. As a result, the fair return on equity for NSPI is higher than that applicable to the typical, average risk Canadian utility.

(6) The fair return for NSPI for 2012 is 10.625% (mid-point of a range of 10.25% to 11.0%), based on the following:

(a) A forecast long-term Government of Canada bond yield of 4.5% for 2012;

(b) A "bare-bones" cost of equity of 10.0% based on the equity risk premium tests, summarized in the Table below:

Table 1

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	9.5%
Discounted Cash Flow-Based	9.5-10.0%
Historic Utility	10.5%-11.0%

(c) A "bare-bones" cost of equity of 9.5% based on the application of the discounted cash flow test to a sample of U.S. electric utilities and a sample of Canadian utilities. The results of the various models applied to the two samples are as follows:

Table 2

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Electric Utilities	9.8%	9.3%	9.5%
Canadian Utilities	10.0%	N/A	8.7%

(d) An allowance for financing flexibility in a range of 0.50% to 1.4%. The lower end of the range represents the minimum required to notionally allow the utilities to maintain the market value of their investment at a small premium to book value. The upper end of the range represents full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures.

(e) The equity risk premium tests and discounted cash flow tests together indicate a "bare-bones" cost of equity for NSPI of 9.75%. The addition of an allowance for financing flexibility in the range of 0.50% to 1.4% results in a fair return on equity of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.

II. FAIR RETURN STANDARD

The requirements to meet the fair return standard arise from legal precedents[1] which are echoed in numerous regulatory decisions across North America.[2] 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.

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.

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.

---

[1] 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))*.

[2] 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).

The three requirements were reiterated in the *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008, March 2009* (pages 6-7).

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.

III. TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS

The following section is intended to provide a review of the trends and changes in the economy and the capital markets since the UARB last reviewed NSPI's allowed ROE and capital structure UARB in detail during the Company's 2005 rates proceeding.

At close of record in the 2005 rates proceeding (January 2005), the Canadian economy was growing moderately and expected to strengthen. Real GDP growth in Canada was an estimated 2.7% in 2004 and expected to improve slightly to 3.0% in 2005. Corporate profits were robust, having risen 18% in 2004. Inflation was relatively tame, with CPI inflation in 2004 under 2.0%.

At the end of 2004, the yields on 10-year and 30-year Canada bonds were 4.3% and 4.8% respectively. Long-term corporate bond yields were approximately 5.75%; A-rated utility bond yields were also approximately 5.75%. Spreads between corporate bond yields and government bond yields were relatively low. Credit spreads were relatively low; the spread between long-term A-rated utility and government bond yields was under 100 basis points.

The equity market (as represented by the S&P/TSX Composite Index) was performing well. From the market trough of the “dot.com” market sell-off (early fourth quarter 2002) to the end of 2004, the S&P/TSX Composite had risen by over 55%.

With the strength in the economy, rising oil prices and an appreciating Canadian dollar, monetary stimulus was being withdrawn by the Bank of Canada by raising its key policy rate (the overnight rate). The Bank of Canada, in its December 2004 *Financial System Review*, noted that the removal of monetary stimulus was expected to entail modest upward movement in interest rates. Consensus Economics, *Consensus Forecasts*, December 2004, anticipated a rise in l0-year Government of Canada bond yields from 4.3% to 5.1% 12 months hence. The challenges to the household sector and some governments (particularly emerging countries) of high debt burdens, along with rising interest rates, were considered to pose some risks to the global financial system, but the BOC considered that borrowers were well positioned overall to deal with higher borrowing costs.

In that economic environment, the UARB rendered Decision NSUARB-NSPI-P-881 (March 25, 2005), in which it approved an ROE for NSPI of 9.3% to 9.8% (mid-point of 9.55%).

The UARB briefly reviewed NSPI’s cost of capital again in the context of the 2006 rates proceeding, at which time the Company was requesting to retain its previously approved ROE.

At the time of that proceeding, economic growth in Canada had remained robust. GDP increased at an annual rate of close to 3.0% in 2005 and was expected to continue at approximately the same rate in 2006. With the economy operating at capacity, the Bank of Canada had continued to raise its key policy interest rate. By the end of 2005, the overnight rate had been increased four times (from 2.25% to 3.25%) since September 2004.

In its October 2005 *Monetary Policy Report*, the Bank of Canada noted that:

(1) business credit conditions had remained advantageous for borrowers, both in Canada and globally;

(2) in financial markets, corporate bond yields and credit spreads had remained low for both investment-grade and non-investment grade borrowers;

(3) the narrow credit spreads reflected healthy corporate balance sheets, continued investor demand for higher yielding securities, and a high level of liquidity in global financial markets; and

(4) easy access to capital markets was indicated by the robust growth in the gross issuance of corporate bonds.

At the end of 2005, the yields on 10-year and 30-year Canada bonds were 4.0% and 4.05% respectively. Government bond yields, despite strong economic growth, had declined to levels below where they had been a year earlier and levels considerably lower than had been anticipated. The relatively low level of government bond yields globally was attributed to the high level of savings relative to investment requirements.

Long-term corporate bond yields had fallen to just over 5%; A-rated utility bond yields were at similar levels. As the Bank of Canada's October 2005 *Monetary Policy Report* noted, spreads between corporate bond yields and government bond yields remained low. In fact, the spread between long-term A-rated utility and government bond yields had not changed materially from the prior year.

Equity markets continued to prove robust; the S&P/TSX composite delivered a total return of 24% in 2005.

In its December 2005 *Financial System Review*, the Bank of Canada noted that the "globally, benign macroeconomic conditions" marked by solid economic growth and low interest rates indicated that the possibility of a shock having a significant negative impact on the Canadian financial system was small. Further, it noted that global financial markets had proved themselves resilient to increased uncertainty resulting from higher energy prices and a possible increase in inflation.

The Company's proposal to maintain its previously approved ROE was unopposed by intervenors and was approved by the UARB in its March 10, 2006 Decision NSUARB-NSPI-P-882.

In its 2007 rates proceeding, NSPI again proposed to retain its previously approved ROE range of 9.3% to 9.8%.

In the intervening year between the 2006 and 2007 rate proceedings, the Bank of Canada's assessment of risks to the financial markets had remained relatively unchanged. In its June 2006 *Financial System Review*, page 3, the Bank noted that while "there continues to be a small risk that the adjustment of global imbalances could slow the growth of the global economy appreciably and increase volatility in financial markets significantly [t]his risk may, however, be lower than previously thought." In its December 2006 *Review*, the Bank noted "the global economic outlook continues to be favourable."

As a result of the continued favourable conditions in the economy and financial markets throughout 2006, the Bank of Canada continued tightening its policy interest rates; increasing the overnight rate four times to 4.25%. At the end of 2006, yields on 10-year and 30-year Canada bonds were 4.08% and 4.14% respectively, little changed from a year previously. In the corporate market, yields on long-term corporate bonds and A-rated utility bonds were virtually identical at 5.2%, and little changed from the end of the prior year.

The Canadian equity markets turned in another exceptional performance in 2006, with the total return on the S&P/TSX Composite Index exceeding 17%.

In the 2007 rates proceeding, NSPI reached a negotiated settlement, approved by the UARB in Decision NSUARB-NSPI-P-886, dated February 5, 2007.

On December 10, 2007, the UARB conditionally approved the establishment of a fuel adjustment mechanism (FAM), as had been proposed, effective January 1, 2009. In its subsequent application for rates (for test year 2009), NSPI requested an ROE of 9.35%, reflecting a reduction of 0.20% from the previously approved ROE. The requested ROE was a component of the framework agreement for the establishment of the FAM that had been signed by various stakeholders.

Between the time of the February 2007 and November 2008 rates decisions, capital markets deteriorated significantly.

Through the first half of 2007, the economy remained strong and financial market developments, in the words of the Bank of Canada (*Financial System Review*, June 2007), "have also been largely favourable. Although there was a brief period of volatility in financial markets in February/March, this volatility has subsided, and risk premiums have since contracted towards the historically low levels observed prior to that period." The Bank of Canada's *Monetary Policy Report Update*, July 2007, referenced a Canadian economy operating above its output potential, strong employment growth and domestic demand, supported by firm commodity prices, and robust economic growth outside North America. According to the Bank, expectations for policy rates in many economies had generally moved up; higher reported longer-term interest rates reflected the expectations of higher real interest rates, consistent with the outlook for continued strong global economic growth.

By the end of July 2007, the Bank of Canada had increased the overnight rate once more, to 4.5%, for eight increases in total since the beginning of 2005. Long-term Canada bond yields had begun to creep up during the first half of 2007, reaching their highest level (4.66%) in over two years in mid-June. At the end of June 2007, with the long-term Canada bond yielding 4.5% and long-term corporate and A-rated utility bonds yielding 5.75% and 5.66% respectively, spreads had moved up only modestly.

Nevertheless, some signs of the upcoming upheaval in the capital markets were already evident in the Bank of Canada's June 2007 *Financial System Review*:

> The exception [to the favourable market conditions] has been the U.S. subprime mortgage market, where a combination of weakness in the housing market and questionable underwriting practices at some institutions contributed to a decline in the credit quality of some U.S. mortgages and certain related credit market instruments.

The Bank pointed to the historically narrow credit spreads on risky assets, and the possibility that low real interest rates may have triggered a widespread search for yield, and an increasing risk appetite, which had contributed to the prevailing low spreads. The Bank expressed some concern that market risk was underpriced, and that a large macroeconomic shock could result in a rapid rise in risk premiums, leading to a widespread and significant decline in asset prices.

In August 2007, the asset-backed commercial paper market locked up, as concerns increased about the quality of the underlying assets in these structured products. In its December 2007 *Financial System Review*, the Bank of Canada announced that the sudden repricing of risk that it had previously considered a possibility had materialized. The Bank noted that risk spreads had widened, volatility in financial markets had increased, and liquidity in the markets for some structured products had evaporated. There was a flight to quality assets; yields on both short and long-term government securities had dropped significantly. Corporate/government bond yield spreads widened and equity markets fell significantly.

In an effort to ease the pressure on credit markets, the Bank dropped its overnight rate to 4.25% in December 2007. As investors fled to safe government securities, yields on 10-year and 30-year Canada bonds had fallen back to 4.0% and 4.1% respectively. In the investment grade corporate debt market, yields had remained virtually unchanged since mid-year, resulting in a widening of spreads. At the end of 2007, the spread between A-rated utility bonds and 30-year Canada bond yields had reached just under 140 basis points.

While the 2007 year-over-year return on the S&P/TSX Composite was close to 10%, equity market volatility had increased materially. During the second half of 2007, the Implied

Volatility Index ("MVX") averaged above 19, close to 40% higher than its 2005-mid-2007 average of 14.[3]

By mid-2008, strains in global credit markets had both broadened and deepened. Aggressive interest rate cuts by the U.S. Federal Reserve, as well as by other major central banks, were undertaken in an effort to stem the liquidity crisis in the global financial system. Between December 2007 and April 2008, the Bank of Canada had cut its overnight rate four times from 4.5% to 3.0%. Between September 2007 and April 2008, the U.S. Federal Reserve had cut the federal funds rate six times, from 4.75% to 2.0%. In addition to policy rate reductions, application of fiscal stimulus began. However, despite these efforts, the crisis in global financial markets intensified, as large financial institutions in the U.S. and Europe collapsed (or nearly collapsed), most notably Lehman Brother in September 2008.

At the end of October 2008, just prior to the UARB's issuance of Decision NSUARB-NSPI-P-888 approving the agreed-to 9.35% ROE, 10-year and 30-year Canada bond yields stood at approximately 3.75% and 4.25%, respectively. However, both long-term corporate bond yields and A-rated utility bonds had risen to 7.6%, increases of almost 200 basis points and 215 basis points, respectively, in ten months, resulting in spreads with long-term Canada bonds of close to 335 basis points.

Between mid-June and the end of October 2008, the S&P/TSX Composite Index had dropped by over a third. During October 2008, the implied market volatility index soared, averaging in excess of 60, over three times its beginning of year level. In November 2008, the MVX hit an all time high of 88.

The crisis in the financial markets spread to real economic activity, triggering a severe global recession. In 4th quarter 2008, the Canadian economy was in recession, although the official

[3] The MVX, introduced by the Montreal Stock Exchange in 2002, was a measurement of the market expectation of stock market volatility over the next month. It was described as a good proxy of investor sentiment for the Canadian equity market: the higher the index, the greater the risk of market turmoil. A rising index reflects the heightened fears of investors for the coming month. The MVX was replaced by a somewhat different measure of implied volatility, called the VIXC, in October 2010. The VIXC still measures market expectation of stock market volatility over the next month.

announcement by the Bank of Canada did not occur until late January 2009. Real GDP growth in Canada for all of 2008 was only 0.5%, with fourth quarter 2008 posting a 3% annualized quarter-over-quarter drop in real growth. The first quarter 2009 decline was more severe, at over 7% quarter-over-quarter (annualized), the largest quarterly decline recorded since comparable data were first recorded in 1961.

By the end of March 2009, the Bank of Canada had cut its overnight rate five additional times, from 3.0% in April 2008 to 0.50% by the end of March, continuing its efforts to restore liquidity, investor and consumer confidence and economic growth. Consistent with negative economic growth, low inflation and investor risk aversion, yields on 10-year and 30-year Canada bonds had declined to 2.8% and 3.6%, respectively. While the absolute yields on long-term corporate bonds had fallen slightly from their January peak, the March 2009 month-end yield of 7.4% reflected a spread with long-term Canada bonds of 380 basis points. A-rated utility bonds were yielding 6.8% (spread of 320 basis points).

During the last months of 2008 and early 2009, the long-term debt market, even for highly rated entities, was essentially closed. Between the end of August 2008 and mid-February 2009, no regulated utility raised any debt in Canada with a term longer than nine years. In December 2008 and January 2009, NSPI raised five-year debt at unprecedented spreads of 400 and 390 basis points respectively over the corresponding term Canada bond.

Through the early part of 2009, equity markets continued to spiral downward. The S&P/TSX Composite hit its trough in early March, having lost 50% of its value since hitting a peak in June 2008.

By mid-year, the massive stimulus programs and monetary policy initiatives implemented globally began to bear fruit. In early June 2009, Finance Minister Jim Flaherty announced that there were cautious signs that the Canadian economy had stabilized. Since that time there has been continued improvement in both the capital markets and the real economies, both in Canada and globally.

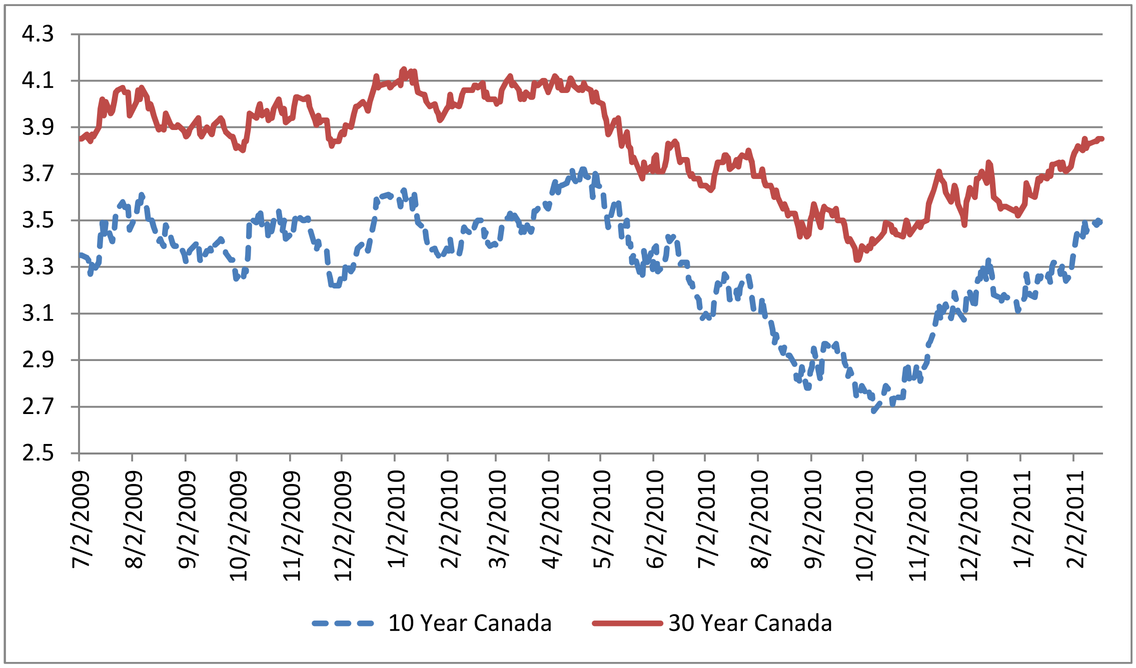
The Canadian economy was declared to be officially out of recession in July 2009. The recovery from the recession started modestly in the third quarter of 2009, and then gained momentum. Real GDP growth rates in 4Q 2009 and 1Q 2010 were 4.9% and 5.4% respectively. After having decreased its target overnight rate 10 times between December 2007 and April 2009 (from 4.75% to 0.25%), the Bank of Canada began to implement increases as the economy appeared to strengthen. The most recent of three increases, to 1.0%, occurred in early September 2010.

However, in October 2010, the Bank of Canada announced that the economic outlook for Canada had changed and it now expected growth to be more muted than previously forecasted. Since that announcement, the Bank has implemented no further changes to the target overnight rate. At 1.0%, the target overnight rate is still lower than at any time prior to the crisis.

Three-month Treasury bill yields, which follow the target overnight rate, have risen from a low of 0.16% in February 2010 to just under 1% at the end of February 2011. The most recent Consensus Economics, *Consensus Forecasts* (February 2011) anticipates an increase of slightly more than 1% (to 2.2%) in three-month Treasury bond yields over the next year. Even with the expected increase to a 2.2% yield, the three-month Treasury bill would be well below long-range levels that would be likely to prevail. Since 1961, the three-month Treasury bill yield on average has exceeded the rate of CPI inflation by 2.2%. With inflation expected to average 2.0% from 2013-2020, Treasury bill yields can reasonably be expected to average approximately 4.0%, 300 basis points above their current level.

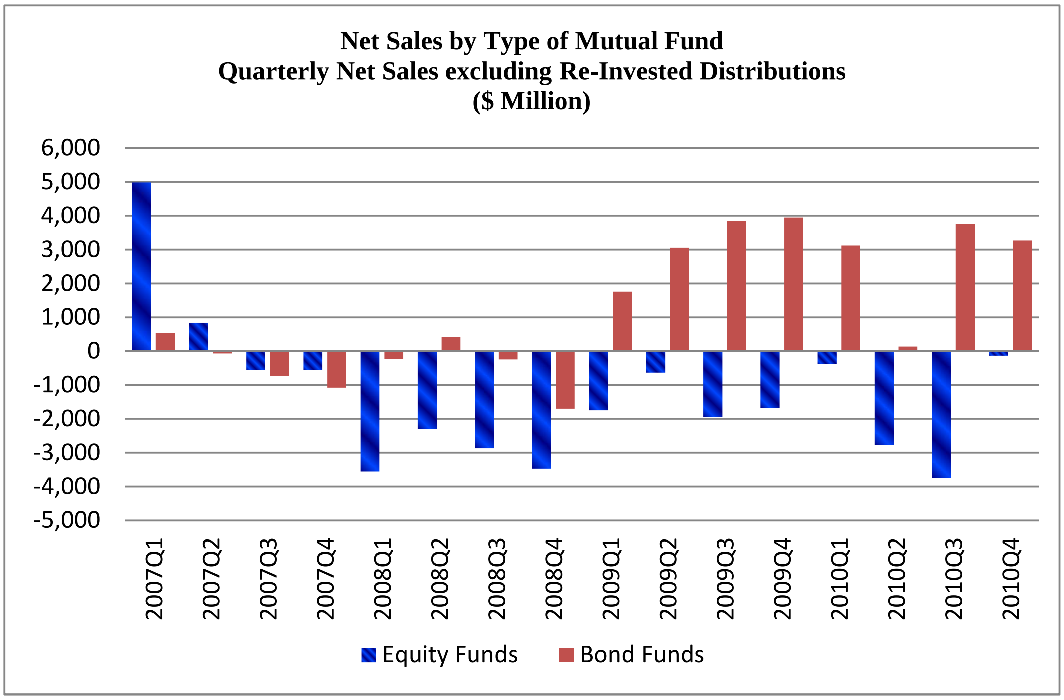
Yields on 10-year and 30-year Government of Canada bonds were relatively flat from the end of June 2009 (approximately the end of the recession) until the end of April 2010, averaging 3.5% and 4.0% respectively. As the outlook for global economic growth tempered, coupled with the sovereign debt crisis in Europe, yields fell. The 30-year Canada bond yield hit a trough of 3.3% at the end of September 2010, the lowest yield observed on long-term Government of Canada bonds since the mid-1950s. Although there has been a gradual uptrend in yields since that time, as shown in Chart 1 below, a subdued recovery in Canada and the other advanced economies, low inflation (expected to be 2.3% and 2.1% in 2011 and 2012 respectively), flows of capital into bonds during 2010 and geopolitical disruptions in the first quarter of 2011 have held 30-year Canada yields below 4%.

Chart 1



With respect to flows of capital into bonds, data compiled by the Investment Funds Institute of Canada (IFIC) show that Canadian investors put a net $10.2 billion into bond mutual funds during 2010, a further $26.1 billion into balanced (debt and equity) funds, while withdrawing a net $7.0 billion from equity mutual funds. Data compiled by Statistics Canada (*Canada's International Transactions in Securities*, December 2010) show that net purchases of Canadian bonds by foreign investors totaled $96 billion in 2010, accounting for close to 85% of net inflows into Canadian securities by foreign investors. Chart 2 below demonstrates by reference to flows into and out of mutual funds that bond funds have, since first quarter 2009, experienced significant inflows, while flows to equity funds have remained largely negative.

Chart 2



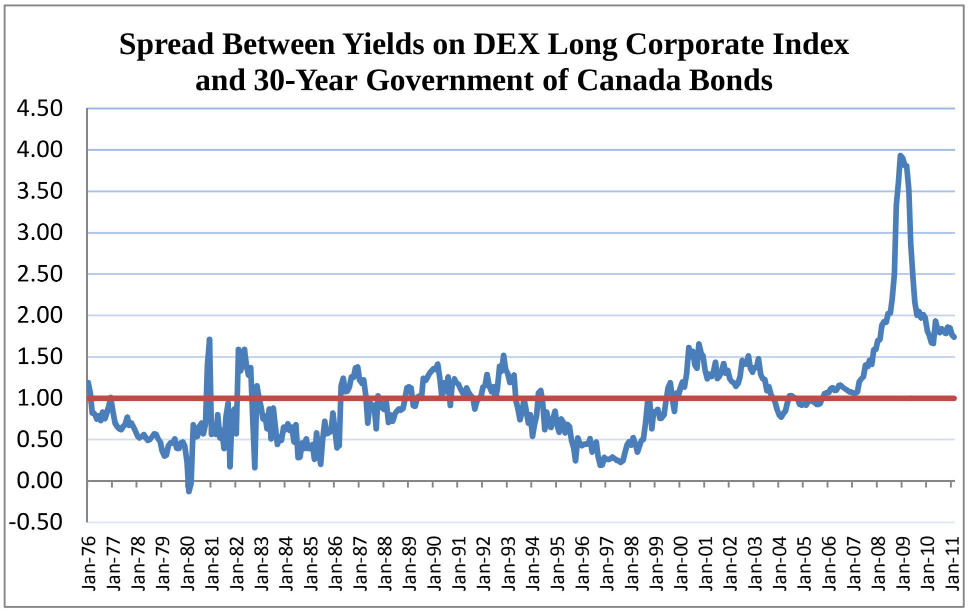
Source: IFIC

At the end of February 2011, the yields on 10-year and 30-year Government of Canada bonds were 3.3% and 3.7% respectively. The March 2011 Consensus Economics, *Consensus Forecasts* anticipates that the 10-year Canada bond yield will reach 3.9% within 12 months; the corresponding long-term Canada bond yield, based on recent (early March 2011) spreads, would be approximately 4.4%.

Spreads on long-term corporate debt have generally continued to narrow since the end of June 2009, although the downward trend was partially reversed in May 2010 with the onset of the sovereign debt crisis in Europe. The spread between the yield on the DEX Long Corporate Index and the 30-year Canada bond fell from 250 basis points at the end of June 2009 to 165 basis points in April 2010, jumping to close to 195 basis points in May 2010. At the end of February 2011, the spread was 174 basis points. As shown in Chart 3 below, despite the significant flows of funds into bonds (both corporate and government) during 2010, spreads remain higher than prior to the financial crisis. The 174 basis point spread observed at the end of

February 2011 compares to a long-term average of 1.0%[4] inclusive of the higher spreads experienced during the financial crisis and of approximately 0.85% up until the beginning of 2007.

Chart 3



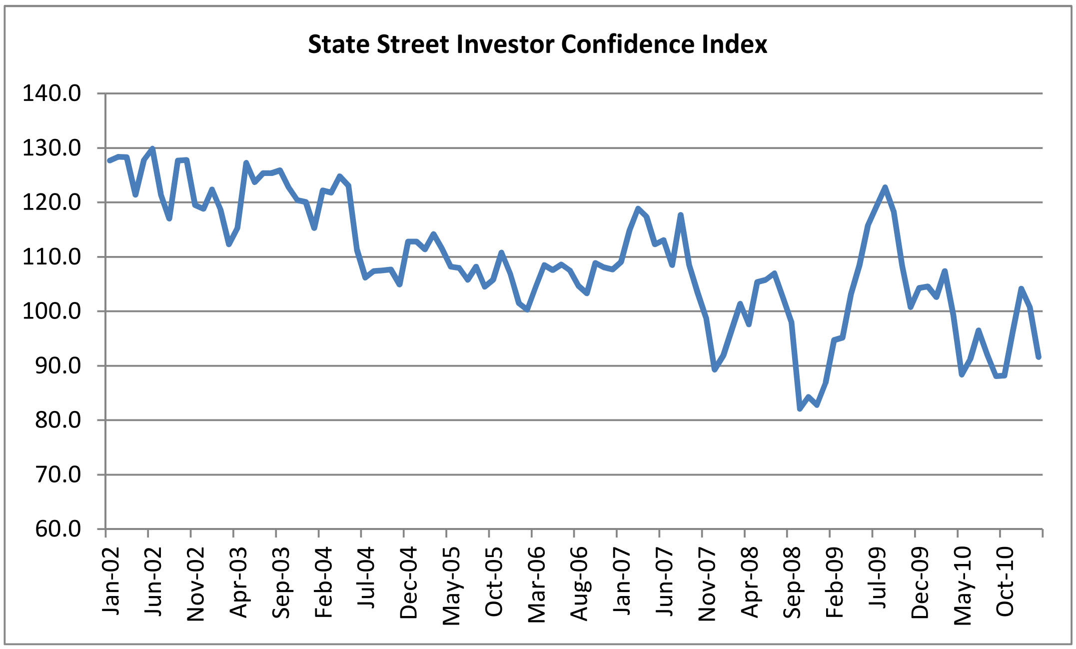
Spreads between long-term Canadian A rated utility bonds narrowed to 140 basis points in April 2010, but then spiked to almost 175 basis points during the height of the sovereign debt crisis in May. At the end of the February 2011, the spread had dipped to just above 140 basis points, still well above the 115 basis point average experienced during the five-year period (2003-2007) prior to the onset of the financial crisis.

Since the end of the recession (from end of June 2009), the equity markets have been fueled by the low interest rate environment, with low borrowing costs helping to boost corporate profits. Pre-tax corporate profits are estimated to have increased 17% in 2010, after declining by 33% in 2009. The S&P/TSX index ended 2010 approximately 15% higher than at the end of 2009, but still over 10% below its 2008 peak. While the expected volatility of the equity market has declined significantly since the worst of the financial crisis, from the beginning of 2010 to the

[4] Measured since 1976 when the yield on the benchmark long-term Government of Canada bond first became available.

end of February 2011, expected volatility has been higher on average than pre-crisis (2004-2007 average) levels. Further, global investor confidence levels remain lower than pre-crisis. Chart 4 below shows global investor confidence levels from January 2002 to late February 2011. The investor confidence levels portrayed in the Chart reflect a quantitative measure of the actual and changing levels of risk contained in investment portfolios representing about 15% of the world's tradable assets.

Chart 4



Source: www.statestreet.com

In October 2010, as noted above, the Bank of Canada announced that the economic outlook for Canada had changed and that a more gradual recovery was expected than had previously been the case. Actual growth in 2010 was 3.1%, the result of a sharp decline in the rate of growth during the second and third quarters of the year, followed by a somewhat higher than expected rate in the fourth quarter. While recovery is expected to continue in 2011 and 2012, the rates of growth are anticipated to lower than in 2010, and relatively modest in the context of recovery from recession. Consensus Economics (March 2011) forecasts growth in 2011 and 2012 at 2.9% and 2.7%. The Bank of Canada's January 2011 *Monetary Policy Report*, prepared prior to the release of the fourth quarter economic performance, anticipated somewhat lower growth rates, at 2.4% and 2.8% for 2011 and 2012 respectively.[5]

The relatively modest pace of growth expected reflects a combination of domestic factors (high household debt, which limits consumer spending) and international factors (e.g., the weak labour and residential real estate markets in the U.S., the strained balance sheets of banks and governments in Europe and austerity programs, and constraints on export growth arising from a combination of tempered growth abroad, the high Canadian dollar and relatively weak productivity).

The facts that (1) Canada fared relatively well compared to other advanced economies during the worst of the financial crisis; (2) economic recovery is underway globally; and (3) capital markets are on materially more solid ground than they were during the depths of the crisis do not mean that it is "business as usual." However, the global economies and capital markets have still not fully recovered and there remain significant risks that there could be a material reversal, of which certain bumps along the way have been constant reminders. The nature of most of these risks, like the financial crisis itself, underscores the extent to which economies and capital markets globally are inter-twined.

The most recent Bank of Canada *Financial System Review*, December 2010, page 2, summed up those risks as follows:

(1) Sovereign debt concerns in several countries;
(2) Financial fragility associated with the weak global economic recovery;
(3) Global imbalances;
(4) The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and
(5) High leverage of Canadian households.

[5] Neither the Consensus Forecast nor the Bank of Canada's forecast would have incorporated the potential impact on economic growth of the crisis in Japan.

With respect to the first, as the Bank of Canada's June 2010 *Financial System Review* concluded:

> While the Canadian financial system has continued to function well in the face of adverse spillovers from Europe, it is vulnerable to renewed stress in the event of a recurrence of severe tensions in global markets. For example, heightened concerns over sovereign debt could lead to higher borrowing costs and/or more rapid tightening of fiscal policy in some European countries, potentially hampering the global economic recovery. In turn, increased uncertainty over global economic prospects could trigger a severe worldwide retrenchment from risky investments. This may lead to market turmoil globally, and possibly even to forced asset sales and liquidity shortages for some institutions. These developments could materially impair the asset quality, capital positions, and funding liquidity of financial institutions, and undermine confidence more generally. Through these indirect channels, sovereign risk could have an impact on the global financial system that is disproportionate to the direct exposure of banks to sovereign debt.

In the December 2010 *Financial System Review*, the Bank of Canada rated the risk to the Canadian financial system from global sovereign debt as high and higher than it was in June 2010.

With respect to financial fragility associated with the weak global recovery, the Bank of Canada noted the more subdued economic recovery than it had anticipated six months earlier, given in part the shift of governments from fiscal stimulus to fiscal consolidation. The Bank noted that, while banks around the world had made substantial progress in repairing their balance sheets, they remain unusually strained and face challenges stemming from the weaknesses in the macroeconomic environment, particularly the labour and real estate markets in Europe and the United States. The Bank concluded that risks arising from the financial fragility associated with a weak global economic recovery were elevated and had increased since they were assessed six months earlier.[6]

[6] The Bank's assessment occurred prior to the onset of political upheaval in Egypt, Libya and other countries in the Middle East, and the crisis in Japan, which could threaten the global recovery in 2011.

In a similar vein, in its October 2010 *Global Financial Stability Report*, the International Monetary Fund stated:

> Despite the ongoing economic recovery, the global financial system remains in a period of significant uncertainty. The baseline scenario is for balance sheets to strengthen gradually as the economy recovers, and as further progress is made in addressing legacy problems in key banking systems. However, substantial downside risks remain. Mature market governments face the difficult challenge of managing a smooth transition to self-sustaining growth, while stabilizing debt burdens under low and uncertain economic prospects. Without further bolstering of balance sheets, banking systems remain susceptible to funding shocks that could intensify deleveraging pressures and place a further drag on public finances and the recovery.

Global imbalances refer to imbalances between savings and investment in the world economies, as reflected in the significant distortions among current account balances, e.g., the large and persistent current account deficit in the U.S. and surplus in China. In its December 2010 *Financial System Review*, the Bank of Canada noted the recent widening of global current account imbalances, warning that the larger they grow, the greater the magnitude of future adjustments required to resolve them. A disorderly resolution, which would be characterized by a sharp adjustment in exchange rates and risk premiums for a wide range of assets, could create significant stresses on financial institutions.

In addition to highlighting concerns with the large current account deficit of the U.S. and the surplus of China, the Bank cited the increasing capital flows to emerging economies since mid-2009. The capital flows (e.g. via funds which invest in emerging market equity and debt) to emerging economies had been putting upward pressure on their currencies and raising concerns about those economies' potential to contribute to excessive credit growth and asset price bubbles. Reaction to capital inflows in some cases has taken the form of tightened controls on capital inflows in an attempt to thwart upward pressure on their currencies. The Bank cited the heightened tensions in currency markets that had been experienced during the prior six months and the increased risk of real and financial protectionism.

The Bank opined that those heightened tensions and the related risks associated with global imbalances could result in a more protracted and difficult global recovery, causing further stress in the financial system. It determined that the risk of market turmoil resulting from global imbalances was high and had risen since its last assessment.

With respect to the potential for excessive risk-taking behaviour, the Bank referred to the extended period of extraordinarily low interest rates in the advanced economies, and that, while such levels are required to stimulate the economies, they may lead to excessive credit creation and undue risk risk-taking in the quest for higher returns. For example, the Bank noted the pressure faced by insurance companies and pension funds to meet their obligations to policyholders and beneficiaries, which could promote risk-taking behaviour. The Bank judged the risk of such behaviour endangering financial stability in Canada in the near-term to be moderate.

Finally, the Bank expressed concern with the growth in household credit, which leaves individuals vulnerable to adverse economic shocks. The risk faced is a transmission to the broader financial system of a decline in the credit quality of loans to individuals as a result of deterioration in economic conditions. The decline in credit quality, in turn, would lead to tighter credit conditions, to further deterioration in real economic activity, and to financial instability. The Bank considered the risk of a system-wide disturbance resulting from financial stress in the household sector to be elevated and somewhat higher than it had been six months previously.

Although there will always be systemic risks to the economy and the financial markets, the breadth and level of those risks far exceeds those envisioned prior to the onset of the financial crisis.[7]

[7] A comparison of the Bank of Canada's December 2006 and 2010 *Financial System Reviews* confirms this.

IV. TRENDS IN UTILITY ALLOWED RETURNS

A. CANADA

At the time of NSPI's 2005 rates proceeding, the vast majority of Canadian utilities were subject to automatic ROE adjustment formulas that changed the allowed ROEs annually by 75% to 80% of the change in forecast long-term Canada bond yields. Most of the formulas had been in place since the mid to late 1990s.[8] The Albert Energy and Utilities Board (now the Alberta Utilities Commission) was the last of the regulators to adopt a formula (2004), although the ROEs they had adopted over the prior decade had followed the formula trends fairly closely. Of the major provincial and federal energy utility regulators, only the UARB, the New Brunswick Energy and Utilities Board and the Island Regulatory and Appeals Commission have not adopted automatic adjustment formulas.[9]

Supported by the fiscal restraint of the Federal government, the achievement and maintenance of low levels of inflation, and the high levels of savings, forecast long-term Government bond yields declined by approximately 375 basis points between late 1994 (when automatic formulas were first adopted) and the beginning of 2005. With many Canadian utilities subject to formulas tied to government bond yields over some or all of that period, the average allowed ROE had fallen by approximately 265 basis points. When the UARB set NSPI's allowed ROE in March 2005, the approved ROE of 9.55% was marginally higher than the industry average of 9.5%.

Over the next several years, as long-term Canada bonds continued to decline, the formula-driven allowed ROEs followed suit. By 2008, the industry average allowed ROE in Canada had dropped to approximately 8.8%.

---

[8] British Columbia Utilities Commission, 1994; National Energy Board, 1995; Public Utilities Board of Manitoba, 1995; Ontario Energy Board, 1997; Public Utilities Board of Commissioners of Newfoundland and Labrador, 1998; and Régie de l'énergie du Québec, 1999.

[9] The Rate Review Panel in Saskatchewan does not regulate the ROE of the Crown-owned utilities. New Brunswick Power is not rate base/rate of return regulated. A formula was proposed by intervenors for Enbridge Gas New Brunswick in its 2010 cost of capital proceeding, but the NB Board did not address the issue in its decision.

The evidence that the formulas were producing returns that did not meet the fair return standard had been mounting for some time.

As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

In its June 2006 *Canadian Hydrocarbon Transportation System* report, the National Energy Board (NEB) reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they had "Buy" recommendations on utility stocks, the recommendations tended to reflect the prospects of the unregulated operations. Analysts also commented that companies had reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views.[10] Some market participants expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated:

[10] The NEB did not consult with analysts for the purpose of their 2008 report, in light of its then ongoing cost of capital proceeding for TransQuébec and Maritimes Pipeline.

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

In *Pipelines/Gas & Electric Utilities*, dated December 7, 2006, Karen Taylor, then equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB,[11] BCUC and OEB[12] formulas] are confiscatory and likely violate the Fair Return Standard."[13]

With the unambiguous divergence between the trends in long-term government bond yields on the one hand and utility bond yields and the market cost of equity on the other during 2008 led other investment analysts to the conclusion that the formula had broken. In RBC Capital Markets' January 16, 2009 *Industry Comment* entitled "Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?", analyst Robert Kwan commented:

> With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).

Mr. Kwan recommended from a risk/reward perspective:

> We would focus on companies with the least exposure to the formula.

A February 23, 2009 report by Macquarie Research entitled *ROE Formula May Finally Bite the Dust* concluded that government bond yields bear little resemblance to any private company's cost of capital. The report also concluded that:

[11] Alberta Energy and Utilities Board, now the Alberta Utilities Commission.
[12] Ontario Energy Board.
[13] Studies commissioned by the Canadian Gas Association and the Canadian Energy Pipeline Association published in 2008 also came to the conclusion that the ROEs produced by the automatic adjustment formulas did not meet the fair return standard.

> 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.

On March 19, 2009 the National Energy Board 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.

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.[14]

Following its decision for TQM specifically, the NEB rescinded its RH-2-94 decision which adopted the automatic adjustment formula.[15] Since the NEB's recission of the formula, Foothills Pipe Lines, Nova Gas Transmission and Westcoast Energy have all reached negotiated settlements with their shippers, all of which included allowed ROEs of 9.7% on 40% common equity ratios.

BMO Capital Markets analyst George Lazarevski in *Pipelines and Utilities* (March 30, 2009) stated:

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.

On April 24, 2009, Scotia Capital commented:

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.
>
> Beginning with the National Energy Board in early 1995, Canadian energy regulators have largely adopted formula-based annual adjustments to utilities' allowed return on equity. These formula have been based on the capital asset pricing model. A base "risk-free" rate, represented by long Canada bond yields, is augmented by an equity risk premium, chosen to represent the business and financial risk of the utilities. The NEB's formula was created in 1994 and 1995, when Canada long bond yields reached over 9% at times, due to a range of factors, including ratings downgrades, large public sector deficits, and bearish domestic and international market sentiment towards Canadian government debt.

---

[14] The NEB also noted that the ATWACC that it had adopted for TQM resulted in an effective ROE of 11.2% on the 32% common equity ratio recommended by the principal intervenor, the Canadian Association of Petroleum Producers.

[15] National Energy Board, *Reasons for Decision, Multi-Client, RH-R-2-94*, October 2009. It is of note that the NEB's decision was for years 2007 and 2008 and was rendered independently of the financial crisis.

> As Canada's public sector reformed its finances, long Canada yields have come down, gradually but steadily, since early 1995. This led to a gradual decline in utility allowed ROEs, which has been a challenge for equity holders, and a challenge for utility management to offset by trying to "over-earn" the regulatory target, which is used to set rates.
>
> The onset of economic and financial market turmoil in late 2007 led to a further, more rapid decline in Canada yields, mimicking the global flight to the safety of top-quality sovereign debt, and reflecting widespread investor aversion to risk of all kinds. This triggered a decrease in Canadian utility regulators' formula-driven ROEs, to unprecedented low levels. However, utility bond spreads, and their cost of equity capital, were rising.
>
> Very recently, the NEB recognized these adverse and undesirable results, in what we view as a very significant Decision in the case of Trans Québec & Maritimes Pipeline. The NEB varied from its formula, which it had applied virtually universally to utilities in its jurisdiction since 1995. The ROE relief was material, lifting TQM's ROE from the formula-set 8.46% and 8.71% in 2007 and 2008 (on the NEB's deemed equity capitalization of 30%) to roughly 11.6% to 11.8%, based on the same capital structure and the embedded cost of debt.[16]

In addition to the NEB, in 2009, the AUC, the BCUC, the OEB, the Newfoundland and Labrador Board, and the Régie, each reviewed the automatic adjustment ROE formulas. While each of the decisions came to somewhat different conclusions regarding the appropriate level of ROE, the cost of equity tests to be accorded most weight and the validity of the formula, all of the decisions increased the allowed ROEs above the level that the automatic adjustment formulas would have produced.

In November 2009, the AUC adopted an allowed ROE of 9.0% for 2010 and on an interim basis for 2011 for all the utilities under its jurisdiction and implemented a 2% across-the-board increase in allowed common equity ratios, subject to some company-specific adjustments.[17] The AUC has instituted a proceeding to set the final allowed ROE for 2011 and to review the utilities' capital structures.

[16] Stephen Dafoe, "Falling Canada Yields and Utility ROEs", *Capital Points*, ScotiaBank Group, April 24, 2009.

[17] For example, the AUC allowed a 3 percentage point increase in common equity ratio for the two electricity transmission utilities that were embarking on major capital build programs.

In December 2009, the Régie adopted a 2010 ROE for Gaz Métro of 9.2%, compared to an ROE of 8.64% which would otherwise have been adopted under the Régie's automatic adjustment formula. The Régie renewed its automatic adjustment mechanism effective for Gaz Métro's 2011 test year. Due to the decline in forecast long-term Canada bond yields subsequent to the December 2009 decision, Gaz Métro's allowed ROE for 2011 will be 9.09%. The corresponding ROE at the forecast 4.5% long-term Canada bond yield for 2012 would be 9.35%.

In its December 2009 decision for Newfoundland Power, the NL PUB set the allowed ROE for 2010 at 9.0% (on a common equity ratio of 44.7% and assuming a forecast long-term Canada bond yield of 4.5%) and later adopted a formula that was quite similar to its previous formula, i.e., it changes the allowed ROE by 80% of the change in long-term Canada bond yields. For 2011, due to the lower forecast long-term Canada bond yield compared to the yield on which the 9.0% ROE was premised, the 2011 ROE is 8.38%. At the forecast long-term Canada bond yield of 4.5% for 2012, the allowed ROE would be 9.0%.

In its December 2009 decision, the BCUC eliminated its automatic adjustment mechanism.[18] 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 Terasen Gas, designated the benchmark utility, effective July 1, 2009 at 9.50%, compared to 8.47% for the first six months of 2009, on a common equity ratio of 40%. The corresponding ROEs effective July 1, 2009 for the smaller gas utilities, Terasen Gas (Vancouver Island), Terasen Gas (Whistler) and Pacific Northern Gas (three

[18] 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.

divisions) were in the range of 9.9% to 10.15%, 40 to 65 basis points point higher than the ROE for the benchmark utility, on equity ratios of 40% to 45%. The allowed ROE for FortisBC, the only investor-owned fully integrated electric utility in Canada other than NSPI, is 9.9% on 40% common equity. There has been no further action taken to change these approved ROEs.

In its, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009, the Ontario Energy Board ("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 also recognized that:

> In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF 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 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 for Hydro One Transmission (9.66%, for rates effective January 1, 2011, on an equity ratio of 40%, based on a forecast long-term Canada bond yield of 3.94%). Based on the forecast of long-term Canada bond yields of 4.5% for 2012 (discussed in Section VII.C.2) and current A-rated utility spreads, the OEB's revised formula would produce an allowed ROE of approximately 9.8%.

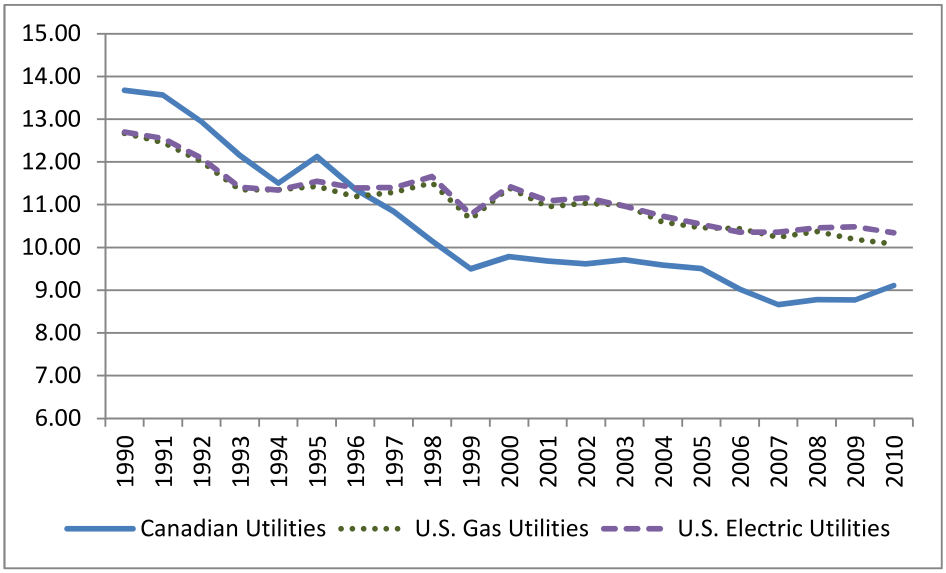
In July 2010, IRAC approved Maritime Electric's requested ROE of 9.75% for 2010 and 2011 on 40% equity and declined to adopt an automatic adjustment formula as proposed by the Consumer Advocate's expert witness, stating that it "sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated."

Taking into account (1) the expectation that interest rates are expected to rise to 4.5% by 2012 and (2) recognizing that the AUC is in the process of setting the final ROE for 2011, the level of ROEs allowed in Canada is not materially different on average than it was in 2005 (when the UARB established the 9.55% ROE for NSPI) and is materially higher than the average ROE adopted for 2009 (the year for which the UARB approved a 9.35% ROE for NSPI).

B. UNITED STATES

Chart 5 below shows that the ROEs approved for Canadian utilities and those approved for electric and gas utilities in the U.S. were relatively comparable until approximately 1996. As the automatic formulas continued to operate as initially constructed, a significant gap between the allowed ROEs emerged, a gap which has persisted through 2009. Between 1996 and 2010, Canadian allowed ROEs have averaged close to 1.2 percentage points lower than the allowed returns of U.S. gas and electric utilities. Over the same period (1996-2010), the average yield on long-term government bonds in the two countries was virtually identical (5.2% in both countries).

Chart 5



Source: Schedule 2, page 3 of 3

To a large extent the difference in the allowed returns stems from (1) the weight given to the Capital Asset Pricing Model in Canadian regulatory jurisdictions, which, due to its construction, results in the allowed ROEs tracking long-term Canada bonds closely and (2) the use of automatic adjustment formulas in Canada, which, because they are premised on a high degree of sensitivity of the utility cost of equity to changes in long-term government bond yields, have resulted in a larger decline in allowed ROEs in Canada versus the U.S.

The average returns allowed for U.S. electric utilities in 2010 was 10.34% (on an average common equity ratio of 48.5%) and for U.S. electric and gas utilities together, 10.24% (on an average common equity ratio of 48.6%).

V. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The analysis starts with the proposition that 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 return on equity 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%.

There are effectively two approaches that can be used to determine a fair rate of return on rate base. The first is to assess the "subject" utility's business risks, then establish a capital structure that (1) is compatible with its business risks; (2) would permit it to achieve a stand-alone investment grade debt rating; and (3) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of the proxy companies' cost of equity to the subject utility without adjustment.

The second approach relies on acceptance of the utility's actual or proposed deemed capital structure for regulatory purposes. 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 then compared against that faced by the proxy firms used to estimate the ROE requirement. If the total risk of the proxy or "benchmark" sample is higher or lower than that of the subject utility, an adjustment to their cost of equity would be required when setting the subject utility's allowed ROE.

Both of these approaches have been taken by regulators in Canada. The first approach has been utilized by the Alberta Utilities Commission (AUC), the National Energy Board (NEB) and the Ontario Energy Board (OEB). The second approach has been used by the British Columbia Utilities Commission (BCUC), the Régie de l'énergie (Régie), and the OEB.[19]

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard.

[19] Historically, the OEB used both capital structure and ROE to recognize differences in business risk among utilities. More recently, it has adopted the same ROE for the utilities it regulates, adjusting for differences in business risk in the capital structure.

Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards. The advantage of the second approach is that it is, in principle, compatible with the philosophy that the capital structure, within a reasonable range, is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. For NSPI, the second approach has been adopted for the estimation of the fair return.

B. SELECTION OF PROXY COMPANIES

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. In principle, the cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment only if the magnitude of the total risks of the sample and the specific utility is comparable.

In Canada, there are only seven investor-owned publicly-traded companies whose operations are largely regulated.[20] These companies are relatively heterogeneous in terms of both operations[21] and size.[22] The relatively small and heterogeneous universe of publicly-traded Canadian regulated companies means that it is impossible to select a sample that would be considered directly comparable in total risk to any specific Canadian utility.

While market data for the Canadian utilities provide a perspective on the fair return for a benchmark utility, a more accurate assessment can be made by relying also on a sample of comparable risk U.S. utilities drawn from a much broader universe and selected using criteria designed to (1) identify companies that are of relatively similar risk to NSPI and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

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

[21] 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.

[22] Ranging from an equity market capitalization of approximately $110 million (Pacific Northern Gas) to $26 billion (TransCanada).

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. Nevertheless, not all utilities in the U.S. would be considered of similar risk to NSPI, just as not all utilities in the U.S. would be similar to each other. Consequently, a proxy sample was selected according to criteria specifically designed to identify utilities of similar risk to NSPI. The selection criteria are set out in Appendix B.

VI. BUSINESS AND FINANCIAL RISK OF NSPI

A. BUSINESS RISK

1. <u>Conceptual Considerations</u>

Business risk is a function of the fundamental characteristics of a utility (e.g., demand, supply and operating factors). Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk. Regulatory risk relates to the framework that determines how the fundamental risks are allocated between the utility's customers and its investors. The regulatory framework is dynamic: it is subject to change as a result of shifts in underlying fundamental risk factors including the competitive environment, energy policy, and regulatory philosophy.

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short- and long-term risks. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term risks that are of primary concern to the investor. Moreover, utility stocks are not typically purchased as short-term investments.

Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, competitive conditions may forestall higher return rewards when the risk materializes. Second, no regulatory board can bind a successor board and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future. Thus, while annual volatility in earnings is a risk factor, longer-term risks are critical elements of the business risk profile of a regulated utility and the determination of a reasonable capital structure and a fair overall return.

2. <u>Overview of NSPI</u>

NSPI is an integrated electric utility providing over 95% of the electricity generated, transmitted and delivered in the Province of Nova Scotia to approximately 490 thousand residential, commercial and industrial customers. Total assets at the end of 2010 were close to $4 billion. The percentage of customers and sales to each customer class are summarized below.

Table 3

	Customers	**Sales (GWh)**
Residential	90.5%	36.2%
Commercial	7.1%	27.0%
Industrial	0.5%	34.1%
Other	1.9%	2.7%

The proportions of total property, plant and equipment (net of general plant) attributable to each of the three main functions are as follows:

Table 4

Function	**Percentage of PP&E**
Generation	68%
Transmission	11%
Distribution	21%

3. Electricity Market Structure in Nova Scotia

NSPI owns and operates a vertically integrated (transmission, distribution and generation) electric utility. 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. 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.

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 who have been designated the supplier of last resort default on their commitment.

4. NSPI's Market

NSPI serves a relatively small economy; the 2009 Nova Scotia GDP of $34 billion represents approximately 2.25% of the total GDP of Canada. The economy is a mix of resource-based industries (e.g., energy and forestry related) and service-based, as Nova Scotia serves as a regional service hub for Atlantic Canada. The province's economy depends 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.[23]

The significant service-related segments of the Nova Scotia economy helped the province to weather the recession relatively well. Nova Scotia experienced one of the lowest percentage declines in GDP in Canada in 2009. However, the resource-based export industries were hard hit. The value of provincial exports declined by almost 25% in 2009, of which energy exports accounted for over 60% of the decline.[24] The energy industry in Nova Scotia remained weak in 2010; the decline in the value of energy exports was close to 40%, due to steep declines in off-shore natural gas production and low natural gas prices. With weak demand abroad, the forestry and forest products industry also experienced significant declines during both 2008 and 2009, resulting in a seven-year stretch averaging approximately 12% per year. The drop of 7% posted by the manufacturing industries in 2009 marked the fifth consecutive year of decline for this sector. The poor performance of industry in Nova Scotia during the recession is reflected in NSPI's 2009 sales volumes. Industrial electricity consumption fell by 12% in 2009; total consumption declined by 4%.

Consistent with a shallower recession, the first year of economic recovery in Nova Scotia was more muted. Real economic growth lagged the rest of Canada (real GDP growth of 1.8% in Nova Scotia versus 3.1% for Canada) during 2010. Strongest growth among industry sectors is expected to be posted by the forestry and forest products industry, with growth in agriculture, the fisheries, and the oil and gas industry all remaining in negative territory. The oil and gas industry is expected to remain weak until the Deep Panuke project begins production at the end

[23] Standard and Poor's, *Nova Scotia Power Inc.*, December 30, 2010.
[24] Foreign Affairs and International Trade Canada, *Canada's State of Trade: Trade and Investment Update – 2010*, page 78, available at www.international/gc/ca/economist-ecnomiste/performance.

of 2011. Although industrial consumption of electricity rebounded last year, it remained below its 2005 peak.

Over the next two years (2011-2012), growth is expected to remain slow. The Conference Board of Canada's *Provincial Outlook*, Winter 2011, anticipates that government austerity measures, limited residential and non-residential investment spending and restrained consumer spending will slow the economic recovery. The Conference Board forecasts that growth in the province during 2011 and 2012, at 1.6% and 1.8% respectively, will lag well behind the rest of Canada (2.7% and 2.0%), despite the significant bump expected from the oil and gas sector in 2012 with the commencement of production from Deep Panuke.[25]

Over the longer-term, demographic factors are expected to be the key constraint on growth. The Conference Board of Canada's *Provincial Outlook 2010* forecasts that Nova Scotia will rank next to last in long-term growth from 2009-2030. The expected annual growth rate of 1.1% over this period (compared to Canada's 2.0%) reflects a deceleration over time, as the population ages, net outmigration occurs, consumer spending shifts away from durable goods to services, and slowing growth in domestic industries, most notably mining (oil and gas) and construction.

5. Electricity 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 2010 owned generating capacity of 2,368 MW was comprised of the following technologies (by percentage):

[25] Other private sector economic forecasters anticipate similar outcomes.

Table 5

Technology	Percent of Capacity (MW)
Coal	52.5%
Dual Fired	14.8%
Natural Gas	12.8%
Hydroelectric	16.7%
Wind	3.2%

The IPPs with which NSPI has contracts own 186 MW of wind and biomass capacity, increasing to 226 MW in 2011. An additional 85 MW of renewable capacity expected to be in service by the end of 2012 is either being build directly by NSPI or will be purchased from IPPs by NSPI pursuant to long-term contracts.

Currently, approximately 83% of the power delivered by NSPI is produced from fossil fuels (64% from coal). The Government of Nova Scotia has taken a leadership role in combating climate change, through the reduction of greenhouse gas (GHG) emissions and other air pollutant emissions and the adoption of an energy strategy that will transition from coal-fired electricity production to electricity produced from renewable resources.

In August 2009, the Government of Nova Scotia issued Greenhouse Gas Emissions Regulations made under the *Environment Act*. Under those regulations, NSPI is subject to caps on GHG emissions. The targets require a reduction in GHG by NSPI of 25% by 2020 from 2009 levels. Failure to meet the caps can result in penalties of up to $500,000 per day. NSPI is also subject to increasingly stringent caps on sulphur dioxide, nitrous dioxide and mercury emissions.

The Government of Nova Scotia first legislated renewable energy targets in 2007 as part of the *Environmental Goals and Sustainability Prosperity Act*, committing to obtaining 18.5% of the province's electricity needs from renewable sources (hydroelectric, wind, tidal, solar, and biomass) by 2013. Renewable Energy Standard Regulations were adopted under the *Electricity Act* (Nova Scotia), which implemented the rules for achievement of the specified requirements, including potential penalties for non-compliance (up to $500,000 per day). In April 2010, the government released a more aggressive plan (the Renewable Electricity Plan), which would legislate obtaining 25% of the province's electricity needs from renewable resources by 2015 and established an objective of 40% by 2020. Amendments to the Renewable Energy Standard Regulations made under the *Electricity Act* in October 2010 implemented the 2015 requirement. The UARB has recognized that the Renewable Energy Standard, which will require an additional 600 to 750 GWh of renewable energy projects between 2010 and 2015, will be a significant challenge for NSPI.[26]

6. 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 conditionally approved by the UARB in Order NSUARB-P-887 (December 2007). Decision NSUARB-NSPI-P-888 (November 2008) approved the implementation of the FAM, effective January 1, 2009, with the Board having satisfied itself that the prerequisites specified in its December 2007 Order had been fulfilled.

The adoption of the FAM was viewed positively by the debt rating agencies. 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. Its 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."

[26] Nova Scotia Utility and Review Board, *In the Matter of an Application by Nova Scotia Power Incorporated for approval of capital work order CI# 39029, Port Hawkesbury Biomass Project, at a cost of $208.6 million* (NSUARB-P-128.10), page 37.

In December 2010, in Decision NSUARB-P-887(2), the Board determined that the 2011 FAM amounts should be recovered over a three-year period, 50% in 2011, 30% in 2012 and 20% in 2013. DBRS responded:

> While DBRS understands that according to the FAM Plan of Administration, the UARB reserves the right to intervene where it believes an increase is not acceptable nor in the public’s interest, the current decision to defer recovery is not favourable for NSPI. While the deferred amount ($53 million) is sizable, DBRS recognizes that under the FAM, NSPI will recover all its fuel costs (including carrying charges) from its customers over the deferral period and, as such, does not view the decision as having a material impact on NSPI’s liquidity nor on the current ratings of A (low), R-1 (low) and Pfd-2 (low). However, DBRS will monitor future FAM filings, noting that a deferral significant enough to have a material effect on NSPI’s liquidity could affect the ratings, particularly in a period of high capital requirements.

S&P also commented as follows:

> An energy cost deferral mechanism, which the Nova Scotia Utility and Review Board (UARB) approved during a December 2010 rate case decision, somewhat weakens the FAM, in our view. While the UARB recognized that energy costs should increase by NSPI's requested amount, it ordered the recovery of the energy cost increase to be spread over multiple years.
>
> We believe that in a period of rising fuel costs, there is now a greater likelihood of a sustained use of an energy cost deferral mechanism to minimize customer rate shock. As a result, a growing deferral balance might put pressure on the ratings because it could increase cash flow volatility and place greater demands on working capital. NSPI's ability to earn a return on the deferral while it remains on the asset side of its balance sheet offsets the adverse effect a deferral balance could have on the company's credit profile, in our view.

In both cases, the potential for the FAM deferral to pressure NSPI’s ratings appears to be a function of the relative size of the amount deferred. In NSPI’s case the amount deferred represents approximately 4.5% of 2010 revenues. A relatively larger deferral, however, from DBRS’ perspective, clearly could pressure NSPI’s debt rating. As regards S&P’s perspective, a comparison between its views regarding NSPI and Maritime Electric Company Limited (MECL) indicates that, if the FAM deferral were to grow relative to NSPI’s total revenues, NSPI’s ratings could come under pressure. With respect to MECL, which had accumulated a large (relative to total revenues) deferral account related to incurred but unrecovered energy costs, S&P stated. “

> We have some concern with the use of an energy cost adjustment mechanism (ECAM) under the existing regulations. In the most recent approved rate order in July 2010, the regulator recognized that the base rate for energy costs should increase and also directed MEC to file a business case analysis with respect to the utility's continued involvement with the Point Lepreau and Dalhousie generating facilities. **Nevertheless, the regulator's desire to minimize rate shock for electricity users is slowing MEC's commodity cost recovery and putting pressure on the rating.** (emphasis added) The ECAM is designed to smooth out the cost of volatile produced and purchased energy costs; in theory, high energy costs are not be immediately passed through but are deferred and then recovered on a rolling12-month basis. However, since 2006, the cost of energy has consistently exceeded the level built into the base rate for consumers. This has caused the deferral balance to rise well beyond our expectations (various rate deferral balances were approximately C$57 million at the end of 2009, or more than 40% of annual revenues). The 2009 regulatory deferral balance was equivalent to about 29% of the year's FFO generation. The adverse effect the deferral balance has on the Maritime Electric's credit profile is **somewhat offset** in our opinion by the company's ability to earn a return on the deferral while it remains on the asset side of its balance sheet. (emphasis added)[27]

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

With respect to how the capital markets view regulatory risk overall in Nova Scotia compared to regulatory risk in other Canadian jurisdictions, the only third party comparisons of which I am aware have been provided by two debt rating agencies, S&P and Moody's.[29] In its most recent debt rating report for NSPI, S&P commented that "In our opinion, NSPI's specific regulatory environment was somewhat less favorable than others in Canada. However, the direction of recent rulings has generally been more favorable. In particular, we viewed the FAM

[27] Standard and Poor's, *Maritime Electric Co. Ltd.*, September 1, 2010.
[28] DBRS, *Nova Scotia Power Inc.*, November 26, 2010.
[29] DBRS has not, to my knowledge, ever provided any comparative assessment. Its commentary on NSPI's regulatory risk in its most recent full debt rating report, issued in November 2010, prior to Decision NSUARB-P-887(2), was specific to Nova Scotia. DBRS found that "NSPI still faces some regulatory risk with respect to the timeliness and certainty of full cost recovery, even though the implementation of the FAM will help to alleviate this. It is expected that the difference between the costs included in rates and the actual costs of fuel will be deferred and refunded to or collected from customers in the subsequent year."

implementation as a positive development that materially reduces the risk associated with volatile hydrocarbon prices."[30] In its last report on NSPI prior to its discontinuation of the debt ratings, Moody's ratings for NSPI on its two regulatory risk factors were the same as the average for other Canadian utilities that it rates.[31] Moody's quantitative methodology for rating electric and gas utilities worldwide considers four main factors: regulatory framework (25% weight); ability to recover costs and earn returns (25% weight); diversification (10% weight); and financial strength and liquidity (40% weight). On the two factors related to regulatory environment, regulatory framework and ability to recover costs and earn returns, Moody's rated NSPI "A", the same average rating that it has accorded other Canadian utilities that it rates.[32]

7. <u>Capital Expenditures</u>

In its most recent debt rating report (November 25, 2010), DBRS noted that NSPI's capital expenditures had increased significantly and estimated that NSPI would spend close to $1 billion over the next several years in addition to maintenance capital (approximately $400 million per year) in order to meet the renewable energy targets, to improve system reliability and to comply with new environmental standards. In 2010 alone, NSPI incurred over $0.5 billion in capital expenditures, largely related to investments in renewable energy projects.

The over $0.5 billion in capital expenditures in 2010 and the anticipated approximately $400 million per year over the next several years represent more than two and a half times the average annual investment in plant, property and equipment of under $150 million made by NSPI during the prior five years (2005-2009).

8. <u>Relative Business Risk of NSPI</u>

Even with the FAM in place, as an integrated utility with more than 50% of its rate base invested in generation assets, NSPI faces higher business risks than the typical regulated Canadian utility.

[30] Standard and Poor's, *Nova Scotia Power Inc.*, December 30, 2010.
[31] Moody's, *Nova Scotia Power Inc.*, November 17, 2009.
[32] Moody's rates electric and gas utilities operating in the provinces of Alberta, British Columbia, Ontario and Newfoundland and Labrador.

The average business risk profile ranking[33] 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".[34] The regulated operations of the majority of the Canadian utilities listed on Schedule 3 are largely "wires" or "pipes" operations (distribution and transmission) that inherently face less business risk than an integrated electric utility (i.e., with generation). Generation operations 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 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[35], are relatively low risk hydro-electric plants. Its purchased power also is primarily generated by hydroelectric plants. In contrast, NSPI's existing generation assets are concentrated in higher risk coal/petroleum coke facilities. NSPI's higher risk relative to FortisBC arises from:

(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.[36] Even with the FAM, NSPI is exposed through the FAM's incentive mechanism to the risk of under-recovering its actual fuel costs and to the risk of cost disallowance.

---

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

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

[35] Maritime Electric and Newfoundland Power have some generation assets, but remain largely distribution utilities. Other investor-owned Canadian utilities have significant generating assets, but the generating assets are not regulated.

[36] 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.

(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 Energy Standard Regulation.

(5) NSPI's requirements to reduce greenhouse gas (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 Chapter V, 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.

NSPI is proposing to maintain the 37.5% common equity ratio that has previously been adopted for rate setting purposes. It is also requesting in this proceeding 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 directed by the UARB in approving the January 2010 ROE Settlement Agreement.

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 materially 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 40%, with a range of 39% (Alberta taxable electricity distributors) to close to 45% (Newfoundland Power) ; (see Schedule 2 page 1 of 3). The average common equity ratio for regulated electric and gas utilities in Canada used for ratesetting purposes is approximately 40%, higher than NSPI's 37.5%; (see Schedule 2 page 1 of 3). The median actual year-end 2009 common equity ratio for investor-owned utilities with rated debt was 41%, higher than NSPI's forecast test-year actual common equity ratio of 37.5%.

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)[37] to Total Debt, and FFO Interest Coverage.[38] 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 6 below, NSPI's three-year average EBIT Interest Coverage, FFO to Debt Ratio and FFO Interest Coverage Ratio have been marginally higher than the medians for investor-owned Canadian utilities with rated debt. DBRS expects the credit metrics to weaken during the capital build cycle, i.e., while capital expenditures are being incurred but before the projects are included in rate base.

Table 6

	EBIT Coverage	**FFO Interest Coverage (2007-2009)**	**FFO/Debt**
NSPI	2.4X	3.2X	15.8%
Investor-owned Utility Median	2.3X	3.2X	14.5%

Source: Schedule 6 page 1 of 2

[37] Funds from Operations 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.
[38] Funds from Operations plus Interest divided by Interest.

Despite slightly higher credit metrics than achieved by the investor-owned utility sector overall, 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 utility median of A-.[39]

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

NSPI's higher business risk, lower regulated and actual common equity ratios, and lower debt ratings compared to its Canadian peers translate into both a higher cost of debt and 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 peer in order to meet the three requirements of the fair return standard. While all of the 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 is embarking on a significant capital program that 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.

VII. FAIR RETURN ON EQUITY FOR NSPI

A. CONCEPTUAL CONSIDERATIONS

1. <u>Importance of Multiple Tests</u>

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity: equity risk premium

[39] 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 A- for all Canadian utilities rated by Moody's.

(including, but not limited to, the Capital Asset Pricing Model), discounted cash flow and comparable earnings tests. Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[40] Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions.[41] These considerations not only emphasize the importance of reliance on multiple tests, but also of benchmarking, or testing the reasonableness of the test results themselves against other relevant information.

Each test has its own set of pros and cons. The discounted cash flow test directly measures utility return expectations. It is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. The comparable earnings test explicitly recognizes that the objective of regulation is to emulate competition and measures returns on the same original cost basis on which utilities are regulated. It is subject to concerns around selection criteria and whether the results are representative of economic returns. The theoretical Capital Asset Pricing Model, framed in an elegant, simple construct, and, on the surface, with only three components, easy to apply, has an intuitive appeal. Nevertheless, it also has its own set of challenges, which are summarized below.

The focus on the challenges of the theoretical CAPM is not to suggest that other tests are necessarily superior, but because Canadian regulators have, in recent years, tended to favour CAPM in their estimation of the allowed ROEs, although recently with clearer recognition of its

---

[40] For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[41] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.

shortcomings and the various adjustments to the "classic" model that may be required.[42] The challenges in the application of the CAPM include:

(1) The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require, in contrast to the return that the investor does require or what returns are actually available to investments of comparable risk.

(2) The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to

---

[42] The British Columbia Utilities Commission (BCUC) and the Ontario Energy Board (OEB), in their 2009 utility cost of capital reviews, recognized the challenges of the CAPM, the need for adjustments, and the need to consider the results of multiple tests.

The BCUC noted:

> that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.
>
> The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd. (BCUC, *Order G-158-09, 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 16, 2009, page 45).

The OEB stated:

> The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate".
>
> This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP [equity risk premium] directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates…
>
> The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP. (OEB, *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* December 11, 2009, pages 45-46)

the country from which the data are drawn and the time period over which they are measured.

(3) The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. The typical application of the CAPM relies heavily on long-term average achieved equity risk premiums in conjunction with a current or forecast risk-free rate.[43] The typical application of the model captures the change in interest rates, but does not capture how the risk premium changes when interest rates change. The need to capture and measure changes in the relative risk of the so-called risk-free security introduces a further complication in the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

(4) The achieved equity market risk premium in Canada is significantly influenced by historic behaviour of the long-term Government of Canada bond. The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

[43] Theoretically, an underlying premise of the CAPM is that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the equity market return is highly correlated with the risk-free rate, that is, the equity market return and the risk-free rate move in tandem. Consequently the application of the test frequently proceeds on an assumption directly in conflict with an underlying premise of the model itself.

(5) The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return.

The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a fair return, particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility industry.

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce "the number" that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.[44]

2. <u>Distinction between Market and Book Values for Fair ROE Determination</u>

Discounted cash flow and equity risk premium models represent conceptually different ways that investors might approach estimating the return they require on the market value of an equity investment. While the discounted cash flow (DCF) and risk premium tests estimate the return

[44] I am strongly of the view that the comparable earnings test is the only test which measures returns in a manner compatible with the base (original cost) to which they are applied. However, I also recognize that the comparable earnings test is the most controversial, not only in terms of its applicability to the estimation of a fair return, but in terms of its application (e.g., criteria for selection of comparables, period over which returns should be measured, need for adjustments for relative risk. In order to limit the issues relevant to the estimation of a fair return, I have applied risk premium and discounted cash flow tests only. However, if the comparable earnings test is to be omitted, the determination of the allowed ROE needs to recognize that market-based costs of equity relate to market value capital structures, not the book value capital structure to which the cost of equity is applied. See Section VII.E. for a full discussion. The application of the comparable earnings test, conducted in the same manner as I previously presented to the UARB, indicates, in isolation, a fair return in the range of 12.5% to 13.0%. In that context, the ROE that I recommend for NSPI is conservative.

required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. The determination of a fair return on book equity needs to recognize that distinction.

In simple terms, assume that the cost of equity for a company whose stock value is $200 is 10%. That means that investors require a return, in dollar terms, of $20. If the book value of the stock is $100, and the 10% cost of equity is applied to the $100 book value rather than the $200 market value, the resulting return in dollar terms is only $10, or half that which investors require.

The proxy companies used for the purpose of estimating the cost of equity have market-to-book ratios of 1.5 X (U.S. sample) to 2.0X (Canadian sample), well in excess of the market-to-book ratio of 1.0 that conceptually would equate the return on book value (in dollar terms) to the return estimated by reference to the market-based DCF or equity risk premium tests.

When the allowed return is applied to an original cost book value, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity so that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value. Failure to make such a conversion will produce an allowed level of earnings that contravenes the fair return standard and will discourage utilities from making investments in critical infrastructure.

B. SELECTION OF COMPARABLE UTILITIES

To ensure comparability with NSPI, only electric utilities categorized by the Edison Electric Institute (EEI) as regulated or mostly regulated utilities were selected. Further, the selection was limited to electric utilities whose operations are focused in states whose electric utility industry is not restructured or where restructuring has been suspended, retail choice is limited to large customers, and the preponderance of customers and load receive a bundled (distribution, transmission and generation) service.

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[45] 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/Baa by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. electric utility sample is BBB+, identical to NSPI. 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 3 and 12).

The median *Value Line* Safety rank of the U.S. electric utility sample is 2 (Schedule 12); the Safety ranks of both of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and Enbridge Inc.) are also 2.[46] In comparison to NSPI, the U.S. utilities have higher common equity ratios (lower financial risk).[47] The average common equity ratio of the sample of U.S. electric utilities (based on the average of the last four quarters ending September 2010) was approximately 45% (Schedule 12), compared to NSPI's deemed common equity ratio for ratesetting purposes of 37.5%, the forecast actual common equity ratio of 37.5% in 2012 and the 40% common equity ratio on which the Company is allowed to earn.

C. EQUITY RISK PREMIUM TESTS

1. Conceptual Underpinnings

An equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in

[45] Standard & Poor's assigns a business risk ranking to each of the companies it rates. There are six business risk categories, ranging from "Excellent" to "Vulnerable". All of the utilities in the proxy sample of U.S. utilities have an "Excellent" business profile, as do the majority of Canadian utilities whose debt is rated by S&P.

[46] 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.

[47] In isolation, the difference in financial risk between a common equity ratio of 50% and a common ratio of 40% is equivalent to a difference in cost of equity of approximately 0.75% to 1.25% at the prevailing utility costs of debt and equity and Canadian income tax rates.

common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

2. <u>Risk-Free Rate</u>

The application of equity risk premium tests require a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of utility assets to which the equity return is applicable.

In the application of the equity risk premium tests, the long-term Government of Canada bond yield expected to prevail during the 2012 test year was utilized. The most recent publicly-available interest rate forecasts expect the 30-year Canada bond to yield approximately 4.5% during 2012.[48] As the economy strengthens, long-term Canada bond yields are expected to rise. Over the longer-term (2013-2020), the 10-year Canada bond yield is expected to average close to 5.0%.[49] The corresponding 30-year Canada bond yield, assuming that the spread reverts to its historical long-term average of 0.30% as the yield curve flattens, would be approximately 5.25%.

[48] The forecasts were provided by BMO Capital Markets, CIBC World Markets, Desjardins, National Bank, Royal Bank of Canada, Scotia Bank Group and TD Securities.

[49] Consensus Economics issues long-term forecasts twice annually, in April and October. Consensus Economics, *Consensus Forecasts*, October 2010 anticipates the 10-year Canada bond yield to average approximately 5.0% from

3. Risk-Adjusted Equity Market Risk Premium Test

3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required equity risk premium for a benchmark utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required equity risk premium for a benchmark utility. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require (in contrast to what the investor does require). Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing principal reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Section VII A. above.

2013 to 2020. The spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.

3.b. Equity Market Risk Premium

3.b.(i) Overview

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, the analysis of historic returns and risk premiums focused on the post-World War II period (1947-2010)[50] as well as on longer periods. My analysis of historic returns and risk premiums was based on the Canadian experience as well as on the U.S. experience as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The U.S. experience is relevant given the close relationship between the two economies, the fact that the U.S. has historically been the single largest alternative destination for Canadian portfolio investment (See Appendix A, page A-14) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

3.b(ii) Historic Returns and Risk Premiums

Table 7 below summarizes the achieved equity and government bond returns and the corresponding experienced risk premiums for Canada and the U.S.[51]

[50] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

[51] The equity and bond market returns in Table 7 represent arithmetic averages of achieved returns. Appendix A explains the rationale for using arithmetic, rather than compound, or geometric averages for the purpose of estimating the expected return from historic returns.

Table 7

Period	Stock Return	Bond Total Returns	Bond Income Returns	Risk Premium Over Bond Total Returns	Risk Premium Over Bond Income Returns
Canada					
1924-2010	11.7%	6.5%	6.0%	5.2%	5.6%
1947-2010	12.1%	6.9%	6.8%	5.2%	5.3%
U.S.					
1926-2010	11.9%	5.9%	5.2%	6.0%	6.7%
1947-2010	12.5%	6.3%	5.9%	6.2%	6.6%

Source: Schedule 7.

The raw data show that, on average, equity returns in Canada have averaged approximately 11.75% to 12.0%, compared to average bond returns of approximately 6.0% to 7.0% (income returns[52]) and 6.5% to 7.0% (total returns), resulting in average achieved risk premiums in the range of approximately 5.25% to 5.5%. The slightly lower achieved equity risk premium relative to bond income returns achieved during the post-World War II period reflects a slightly higher average equity return relative to the longer period, which was more than offset by higher bond income returns.

The corresponding raw data for the U.S. indicate average equity market returns of approximately 12.0% to 12.5%, corresponding to average bond returns of approximately 6.0% to 6.25% and an achieved equity risk premium above 6.5%.

3.b.(iii) Canadian Equity and Government Bond Returns

To assess whether there has been a trend in the underlying returns which generate the achieved risk premiums, the returns and risk premiums for each decade over the period 1931 to 2010 were examined and are presented in Table 8 below.

[52] The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield.

Table 8

10-YEAR AVERAGE CANADIAN MARKET RETURNS					
	Canadian Stock Returns	**Canadian Bond Total Returns**	**Canadian Risk Premium Over Bond Total Returns**	**Canadian Bond Income Returns**	**Canadian Risk Premium Over Bond Income Returns**
1931-1940	5.6%	5.7%	-0.1%	3.8%	1.9%
1941-1950	16.7%	3.1%	13.6%	2.9%	13.8%
1951-1960	12.3%	1.1%	11.1%	3.9%	8.4%
1961-1970	10.2%	4.4%	5.9%	5.9%	4.3%
1971-1980	15.5%	4.1%	11.3%	8.9%	6.5%
1981-1990	8.6%	13.8%	-5.2%	11.6%	-3.0%
1991-2000	13.8%	12.9%	1.0%	7.5%	6.4%
2001-2010	8.7%	7.4%	1.3%	4.6%	4.1%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; *TSX Review*.

Table 8 indicates a clear pattern in bond returns, reflecting:

(1) rising bond yields in the 1950s through the mid-1980s, which produced capital losses on bonds and low bond total returns;

(2) high total bond returns and yields in the 1980s, reflecting the high rates of inflation; and,

(3) high bond total returns in the 1990s and the 2000s, relative to income returns, reflecting the secular decline in long-term government bond yields, which resulted in capital gains and total bond returns, well in excess of the concurrent bond yields.[53]

In contrast to the pattern in bond returns, Table 8 does not indicate a discernible pattern in equity market returns.[54]

[53] The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.
[54] Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2010 and 1947-2010 are estimated at 0.00 for both periods.

However, further analysis of the historical data indicates, as shown in Table 9 below, that, historically, lower bond income returns have been associated with higher achieved risk premiums.

Table 9

	Averages for the Period: 1924-2010			Averages for the Period: 1947-2010		
Bond Income Returns:	**Equity Returns**	**Bond Income Returns**	**Risk Premium**	**Equity Returns**	**Bond Income Returns**	**Risk Premium**
Below 5%	13.1%	3.7%	9.5%	15.0%	3.6%	11.5%
Below 6%	11.5%	4.2%	7.3%	12.2%	4.4%	7.8%
Below 7%	11.7%	4.3%	7.3%	12.5%	4.6%	7.8%
Below 8%	12.1%	4.6%	7.6%	13.1%	5.0%	8.1%
Below 9%	11.1%	5.0%	6.2%	11.5%	5.5%	6.0%
All Observations	11.7%	6.0%	5.6%	12.1%	6.8%	5.3%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009; TSX Review*.

Table 9 above indicates that, except at the lowest levels of long-term Government of Canada bond income returns, average equity returns were in the range of approximately 11.5% to 12.5% during the two periods. Further, at bond income returns below 8%, the equity risk premium averaged approximately 7.5% to 8.0%. Only when the highest levels of bond income returns are included do the average achieved equity risk premiums drop to approximately 6% and then to 5.0% to 5.5%. In other words, the historical data indicate that the equity risk premium has varied with bond yields, i.e., higher risk premiums at lower levels of bond yields and vice versa.

The forecast long-term Canada bond yield for 2012 is approximately 4.5%, approximately 1.5 percentage points lower than the long-term average bond income return and 2.25 percentage points lower than the post-World War II average bond income return. Over the longer-term, based on the Consensus Economics, *Consensus Forecasts,* October 2010, the long-term Government of Canada bond is anticipated to yield approximately 5.25%. Although *Consensus Forecasts* expect yields to rise, the anticipated average yield going forward is still well below the average income and bond returns achieved historically. While the longer-term forecast of the long-term (30-year) Government of Canada bond yield of approximately 5.25% lies within the range of yields that have been associated with average achieved equity risk premiums of approximately 6.0% to 6.25%, the 2012 forecast long-term Government of Canada bond yield (4.5%) suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, in the range of 7.25% to 8.0%.

3.b(iv) Comparison of Canadian and U.S. Returns and Risk Premiums

A comparison of the returns in Canada and the U.S. over the longer-term and the post-World War II period shows that the equity market returns in the two countries have been similar. On average the achieved equity market returns in the two countries have been in the approximate range of 11.75% to 12.5% (see Table 7 above).

Despite relatively similar equity market returns, the achieved risk premium in Canada has been approximately 1.3% to 1.5% lower than in the U.S. The difference in the equity market returns accounts for only 0.2% to 0.4% of the difference in the observed risk premiums. The preponderance of the difference is attributable to higher bond returns historically in Canada. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points.

With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) declined and the differential between Canadian and U.S. government bond yields that existed historically fell. Between 1998 and 2010, the average yield on 10-year Government of Canada bonds was only slightly higher (+6 basis points) than the corresponding average yield on 10-year U.S. Treasury bonds. The corresponding differential between the yields on the long-term (30-year) government bonds was -13 basis points. As indicated above, the yields (and expected returns) on long-term Government of Canada bonds are expected to be in the approximate range of 4.5% to 5.25% in the near-term (2012) and longer-term (2013-2020) respectively, which compares to approximately 5.0% to 5.5% for the U.S.[55]

[55] Blue Chip *Financial Forecasts*, February 1, 2011for 2012 and December 1, 2010 for the longer term.

With respect to the relative risk of the two equity markets, the historic annual volatility in the two markets over the longer-term has been quite similar. The Table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2010 and post-World War II (1947-2010) for the two countries.

Table 10

	Canada			United States		
	Arithmetic Average	**Standard Deviation**	**Compound Average**	**Arithmetic Average**	**Standard Deviation**	**Compound Average**
1926-2010	11.5%	18.9%	9.8%	11.9%	20.4%	9.9%
1947-2010	12.1%	17.0%	10.8%	12.5%	17.5%	11.0%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*, www.standardandpoors.com, *TSX Review*.

To put the differences in the relative risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns. For the longer period, 1926-2010, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the difference in Canada was 1.3%; in the U.S. it was 1.5%, a difference of 0.2%. The two differentials between the Canadian and U.S. arithmetic and compound average returns can be interpreted as the difference in equity return required for the difference in volatility between the two markets. In other words, based on the longer period, the equity market return required would be 0.30% higher in the U.S. than in Canada and based on the post-World War II period, the equity market return required would be 0.2% higher in the U.S. than in Canada. In both cases, the differences are *de minimus*.

Since the beginning of the financial crisis (August 2007) to the end of February 2011, the two markets have exhibited similar volatility; the standard deviations of weekly price changes in the two countries have been virtually identical.

Table 11

Standard Deviations of Weekly Price Changes		
	S&P/TSX Composite (Canada)	**S&P 500 (United States)**
01/08/07-28/02/11	3.4%	3.5%
18/08/08-28/02/11	3.8%	3.8%

Source: www.yahoo.com

With similar government bond yields in the two countries for more than a decade, the U.S. historic equity market risk premium is a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors. Further, bond yields in Canada are expected to be similar to, or lower than, the bond income returns underpinning the achieved equity risk premiums in the U.S. Given the similarity of achieved equity market returns in the two countries, and the expected lower bond returns in Canada compared to both the historical bond returns in Canada and in the U.S., the achieved U.S. equity risk premium of no less than 6.5% represents a conservative estimate of the forward-looking equity risk premium for the Canadian market.

3.b.(v) Impact of Inflation on Equity Market Returns[56]

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking equity nominal (inclusive of inflation expectations) market return

[56] The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital. I analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward. The analysis is summarized in Appendix A.

should differ from the historic nominal returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in both Canada and the U.S. has been higher than the expected rate of inflation. The arithmetic average CPI rate of inflation from 1926-2010 in Canada was 3.1%; the corresponding rate of inflation in the U.S. was also 3.1%. The most recent consensus long-term (2011-2020) forecast of CPI inflation for Canada is 2.0%; for the U.S., it is 2.1%.[57] The lower forecast rate of inflation compared to the historical rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically.

However an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table 12 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

Table 12

	Canada			**U.S.**		
Inflation Range	**Nominal Equity Return**	**Average Rate of Inflation**	**Real Equity Return**	**Nominal Equity Return[1/]**	**Average Rate of Inflation[1/]**	**Real Equity Return[1/]**
Less than 1%	15.7%	-1.4%	17.0%	13.2%	-2.0%	15.2%
1-3%	13.0%	1.9%	11.1%	18.4%	2.0%	16.4%
3-5%	4.8%	4.1%	0.7%	6.2%	3.6%	2.6%
Over 5%	12.5%	9.2%	3.3%	7.0%	8.2%	-1.2%
Avg. 1924-2010	11.7%	3.0%	8.6%	11.9%	3.1%	8.8%

[1/] U.S. data are calculated over the period 1926-2010

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009;* www.federalreserve.gov*;* Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook;* www.standardandpoors.com; www.statscan.ca; *TSX Review.*

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation for the purpose of estimating the future equity risk premium. The average nominal equity returns in Canada were approximately 11.7% over the longer-term and 12.1% since the end of World War II.

[57] Consensus Economics, *Consensus Forecasts*, October 2010.

3.b.(vi) Equity Market Risk Premium

Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis[58], and the observed negative relationship between real equity returns and inflation, a reasonable expected value of the equity market return is a range of 11.5% to 12.0%, based on Canadian equity market returns and supported by U.S. equity market returns. The expected return on long-term Canada bonds, based on both the near-term (2012) and the longer-term forecasts of the 30-year Canada bond yield, is in the range of 4.5% to 5.25%. The resulting expected equity market risk premium is approximately 6.75% to 7.0%. An analysis of Canadian equity risk premiums in conjunction with bond income returns indicates that an equity risk premiums of 7.25% to 8.0% has been associated with a bond income return of approximately 4.5%, i.e., similar to the forecast 2012 Government of Canada bond yield. The achieved equity risk premium in the U.S. supports a lower bound on the estimate of the market equity risk premium for Canada at the forecast levels of bond returns of no less than 6.5%. Therefore, a reasonable estimate of the expected value of the equity market risk premium at the forecast 2012 long-term Government bond yield is thus in the range of 6.5% to 8.0%, or approximately 7.25% (equivalent to an equity market return of 11.75% at the 2012 forecast 4.5% long-term Canada bond yield).

3.c. Relative Risk Adjustment

3.c.(i) Overview

The market risk premium result needs to be adjusted to recognize the relative risk of a benchmark utility. The theoretical CAPM holds that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments. In the simple, one risk variable CAPM, the non-diversifiable risk is captured in beta.

[58] The P/E ratio analysis is included in Appendix A.

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

(1) The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

(2) The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

(3) The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement.

(4) Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

(5) While investors can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot.

Thus, a risk measurement that reflects those considerations is relevant for estimating the benchmark utility equity risk premium.

3.c.(ii) Total Market Risk

These considerations support focusing on total market risk, as well as on beta, to estimate the relative risk adjustment for a benchmark utility. The absence of an observable relationship between "raw" betas and the achieved market returns on equity in the Canadian market[59] provides further support for reliance on total market risk to estimate the relative risk adjustment.

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total risk of a benchmark utility, the S&P/TSX Utilities Index was used as a proxy. The standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, including the Utilities Index, were calculated over five-year periods ending 1997 through 2010 (Schedule 8).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The <u>relative</u> market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 8 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(iii) Historic Raw Betas of Canadian Utilities

Schedule 11 summarizes the "raw"[60] betas calculated using monthly changes in price[61] for individual publicly-traded Canadian regulated pipeline, gas distribution and electric utility

[59] See Appendix A.
[60] The term "raw" means that the beta is simply the result of a single variable ordinary least squares regression.
[61] The use of price betas for utilities has been criticized on the grounds that the exclusion of dividends from the calculated betas overestimates the betas. A comparison of price and total return (including dividends) for Canadian utilities showed that there was no material difference between the two.

companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector[62] using monthly price data calculated over five-year periods ending 1993 through 2010.

As Schedule 11 indicates, there was a significant decline in the calculated "raw" five-year betas of the individual regulated Canadian companies between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative). Following an increase in 2007 to 0.50, the "raw" monthly betas for the individual regulated Canadian company betas again declined in 2008 to approximately 0.25 and have remained at that level through the end of 2010.[63]

The observed levels and pattern of the calculated "raw" utility betas in 1999-2010 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the greater sensitivity of utility stock prices than the equity market composite to rising and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006); and (4) the more extreme price changes of the market as a whole during the financial crisis and the subsequent market recovery.[64] Over the longer term (1970-2010), the "raw" beta of the Utilities Index calculated using total returns has been close to 0.50, as indicated in Table 13 below.

[62] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

[63] There can be significant differences in measured betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices. The table below shows that, for the five large publicly-traded Canadian utilities, whose shares are regularly traded, the median five-year beta ending December 2010 calculated using weekly price changes was twice as higher as the corresponding median beta calculated using monthly price changes.

	Canadian Utilities	**Emera**	**Enbridge**	**Fortis**	**TransCanada**	**Median**
Weekly	0.39	0.40	0.49	0.50	0.44	0.44
Monthly	0.06	0.21	0.32	0.16	0.39	0.21

[64] Schedule 9 shows that utilities were not the only companies whose betas were negatively impacted by the technology sector bubble and subsequent market decline. To illustrate, the 60-month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87.

3.c.(iv) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded regulated Canadian company shares and of the utility index explain a relatively small percentage of the actual achieved market returns over time. A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2010[65] shows the following:

Table 13

$$\text{Monthly TSX Utilities Index Return} = 0.0059 + 0.47 \left\{ \text{Monthly TSE Composite Return} \right\}$$

t-statistic	=		13.8
R^2	=	28%	

The relationship quantified in the above equation suggests a long-term utility beta of 0.47. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 28%. That means 72% of the monthly volatility in share prices remains unexplained.[66]

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly long-term Canada bond returns to the analysis indicates the following:

[65] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2010.

[66] As shown in Schedule 11, page 2 of 2, the R^2s of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2010 have been extremely low, averaging less than 10%. The low R^2s indicate that very little of the volatility in the utility share prices is explained by the volatility in the equity market composite. It bears noting that, while the 2006-2010 "raw" beta of Canadian Utilities Limited, at 0.06, is the lowest of the individual Canadian utilities, its absolute price volatility, measured by the standard deviation of monthly price changes, was the highest of the group.

Table 14

$$\begin{array}{l} \text{Monthly TSX Utilities Index Return} = 0.0026 + .41 \left\{ \begin{array}{c}\text{Monthly TSE} \\ \text{Composite} \\ \text{Return}\end{array} \right\} + .47 \left\{ \begin{array}{c}\text{Monthly} \\ \text{Long Canada} \\ \text{Bond Return}\end{array} \right\} \end{array}$$

t-statistics	=	12.4	8.5
R^2	=	37%	

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (37% versus 28%). The second regression equation suggests that utility shares have had approximately 40% of the volatility of the equity market and approximately 47% of the volatility of the bond market, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility shares' volatility unexplained. To provide some perspective, the average actual annual return for the index from 1970-2010 was 12.9%. Of this average annual return, just over 3.0 percentage points was explained neither by volatility in the equity market nor by the long-term government bond market.[67] The persistent large unexplained component of the achieved utility return should be recognized in the estimation of the relative risk adjustment.

By solving the regression equation (including the intercept) in Table 14, using current estimates of the market return and the long-term Canada bond return, the expected utility return can be estimated. At an expected annual equity market return of 11.5%-12.0% (as developed above), an annual 30-year Canada bond return of 5.25% (equal to the forecast long range expected yield of 5.25%), and the equation intercept (equal to the annual historical average "unexplained" utility return of 3.2 percentage points), the indicated expected utility return is 10.5%.[68] Alternatively, the prospective "unexplained" component of the utility return can be estimated to be in the same proportion to the total utility return as was the case historically (approximately 25%[69]). In this case, the expected utility return is 9.7%.[70] The average of the two utility return estimates is

[67] The unexplained component of the achieved return is represented by the intercept in the equation. The intercept of 0.0026 (or 0.26%) is a monthly return, which when annualized, equals 3.2%.
[68] 10.5% = 3.2% + (0.41*11.75%) + (0.47*5.25%).
[69] 3.2%/12.9% ≈ 25%.
[70] 9.7% = ((0.41*11.75%) + (0.47*5.25%))/ (1-25%).

10.1%; the corresponding utility risk premium above the forecast long-term Canada bond yield of 5.25% is 4.8%. The indicated market risk premium using the same equity market return estimate of 11.75% and long-term Canada bond return of 5.25% is 6.5%. The resulting utility relative risk adjustment is 0.74.[71]

3.c.(v) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that regulated companies are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely, stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.[72]

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, is a partial recognition of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted historical betas are a standard means of estimating expected betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0.

The following Table compares recent reported Bloomberg betas (calculated using three years of weekly prices)[73] for the five major Canadian utilities to calculated "raw" weekly betas for a

[71] $\frac{10.1\% - 5.25\%}{11.75\% - 5.25\%} = 0.74$

[72] See Appendix A, page A-21.

[73] Retrieved from www.bloomberg.com on January 13, 2011.

similar three-year period. The Bloomberg betas suggest that the relative risk adjustment based solely on the most recent Canadian regulated company betas would be approximately 0.60. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of approximately 0.50 for the TSX Utilities Index shown in Table 13 above results in a relative risk adjustment of 0.67.[74]

Table 15

Company	**"Raw" Beta**	**Bloomberg Beta**
Canadian Utilities Ltd.	0.37	0.55
Emera Inc.	0.41	0.63
Enbridge Inc.	0.46	0.54
Fortis Inc.	0.51	0.62
TransCanada Corp.	0.42	0.60
Median	**0.42**	**0.60**

Source: www.yahoo.com and www.bloomberg.com.

A comparison of the reported *Value Line* betas[75] to the "raw" calculated betas for the sample of U.S. electric utilities relied upon in the application of the discounted cash flow (DCF) and DCF-based risk premium tests shows a similar relationship. While the "raw" calculated weekly betas for the five-year period ending December 27, 2010 averaged approximately 0.59[76], the 4th Quarter 2010 betas reported by the widely disseminated *Value Line* averaged approximately 0.70 for the sample (Schedule 12).

[74] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.
[75] *Value Line* uses a five-year horizon and a weekly price change interval.
[76] The calculations of the sample betas are sensitive to the period over which the betas are calculated, the price interval chosen to estimate the betas as noted above (e.g., weekly versus monthly) and the market index selected (e.g., S&P 500 versus the NYSE Index). The betas calculated using monthly data are systematically lower than the betas calculated using weekly data for the U.S. electric utility sample.

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the Table below:

Table 16

Relative Risk Indicator	**Relative Risk Factor**
Total Market Risk (Standard Deviations)	0.65-0.70
Relative Historic Returns and Betas: Canadian Utilities	0.74
Recent Adjusted Beta: Canadian Utilities	0.60
Long-term Adjusted Beta: Canadian Utilities Index	0.67

These results support a relative risk adjustment for an average risk Canadian utility in the approximate range of 0.65-0.70. For NSPI, which is of higher risk than the average Canadian utility, the relevant relative risk adjustment would be, conservatively, at the upper end of the range, i.e., at 0.70. A 0.70 relative risk adjustment is equivalent to the recent average adjusted beta for the U.S. electric utility sample.

3.d. <u>Equity Risk Premium and Cost Of Equity</u>

The equity market risk premium was previously estimated to be in the range of 6.5% to 8.0% (mid-point of approximately 7.25%) at the 2012 forecast yield of 4.5% for long-term Government of Canada bonds. At an equity market risk premium of 7.25% and a relative risk adjustment of 0.70, the indicated equity risk premium for NSPI is approximately 5.0%. The corresponding cost of equity at the 2012 forecast long-term Canada bond yield of 4.5% is approximately 9.5%.

4. <u>DCF-Based Equity Risk Premium Test</u>

4.a. <u>Overview</u>

The Discounted Cash Flow-Based ("DCF-Based) Equity Risk Premium Test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds.

The DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by analyzing regulated company equity return data. In contrast, the risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly. The DCF-based risk premium test was applied to a sample of U.S. electric utilities.[77] The DCF-based risk premium test was applied to the sample of U.S. electric utilities only because its application requires a consistent time series of long-term growth rate forecasts, which is not available for Canadian utilities.

4.b. Construction of the Constant Growth DCF-Based Equity Risk Premium Test

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the utilities in the sample from 1995-2010.[78] The monthly DCF cost of equity for each utility was estimated as the sum of the utility's I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S mean earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 13, page 1 of 4). The monthly sample average constant growth ERPs were used to estimate the regression equations found on Schedule 13, page 2 of 4.

[77] The selection criteria for the sample of U.S. electric utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.

[78] The analysis comprises the full period over which automatic ROE adjustment formulas for setting allowed ROEs were (and in some cases continue to be) in effect in Canada. The period for the analysis was chosen in part to test the validity of the relationship between interest rates and the equity risk premium on which most of the automatic ROE adjustment formulas have been based.

4.c. Constant Growth DCF-Based Equity Risk Premium Test Results

For the sample of U.S. electric utilities, the DCF-based equity risk premium test indicates that the average 1995-2010 equity risk premium was 5.0%, corresponding to an average long-term government bond yield of 5.3%. The data also show that the risk premium averaged 2.4% when long-term government bond yields were 7.0% or higher and 5.9% when long-term government bond yields were below 5.0%.

The Table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1995-2010 analysis.

Table 17

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	6.0%-7.0%	Above 7.0%
Utility Equity Risk Premium	7.4%	5.7%	5.1%	3.4%	2.4%

Source: Schedule 13, page 1 of 4.

The data indicate that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

A key advantage of the DCF-based risk premium test is that it can be used to test the relationship between the cost of equity (or risk premiums) and interest rates (and/or other variables).[79] In the application of this test, the relationships between the utility risk premiums and long-term government bond yields and between utility risk premiums, long-term government bond yields and the spread between the yields on long-term utility and government bond yields have been examined.

[79] Of the three equity risk premium tests, the DCF-based equity risk premium test is the only one that lends itself to explicitly estimating the relationship between utility equity risk premiums (or the utility cost of equity) and interest rates.

The single independent variable regression analysis used monthly 30-year government bond yields as the independent variable and the corresponding utility equity risk premiums as the dependent variable. The analysis for this specific sample indicated that, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 125 basis points, or alternatively, expressed in cost of equity terms, the ROE is lower at higher levels of long-term government bond yields. This incongruous result is due in part to the rising estimated costs of equity during the early 2000s, even as long-term government bond yields were falling, as industry restructuring and consolidation gave rise to forecasts of higher earnings growth. (Schedule 13, page 1 of 4) It is also due in part to the fact that factors other than long-term government bond yields are determinants of the cost of equity.

To capture the impact of other factors, corporate bond yield spreads were incorporated into the analysis. The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' risk perception or willingness to take risk. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[80] In the two independent variable regression analysis, government bond yields and the spread between long-term Baa-rated utility and government bond yields were both used as independent variables and the utility equity risk premium was the dependent variable. The two independent variable analysis indicates that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.

Specifically, the analysis showed that the utility equity risk premium increased or decreased by slightly more than 90 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately 12 basis points for every 10 basis point increase or decrease in the long-term Baa utility/government bond yield spread (Schedule 13, page 2 of 4).

[80] Examples include: Chen, N. F., R. Roll and S. A. Ross, 1986, "Economic Forces and the Stock Market", *Journal of Business*, 59, pages 383-403 and Harris, R.S. and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Summer 1992, *Financial Management*, pages 63-70.

During 2010, the spread between yields on NSPI's long-term bonds and 30-year Government of Canada bond yields was approximately 165 basis points. At a forecast long-term Government of Canada bond yield of 4.50% and a long-term utility/government bond yield spread of 165 basis points, the two independent variable DCF-based equity risk premium model indicates an equity risk premium of approximately 5.4%. The corresponding utility cost of equity is approximately 9.9% (Schedule 13, page 2 of 4).

The two independent variables (the government bond yield and the utility/government bond yield spread) can be collapsed into a single independent variable, the long-term Baa-rated utility bond yield. When the long-term Baa-rated utility bond yield was used as the sole independent variable and the equity risk premium is measured as the DCF cost of equity minus the corresponding Baa-rated utility bond yield, the resulting relationship was:

Risk Premium Over Baa Utility Bond Yield = 7.3 - 0.58 Baa Utility Bond Yield

In other words, the analysis indicated that the utility cost of equity rose and fell by approximately 40% of the change in the long-term Baa-rated utility bond yield (Schedule 13, page 2 of 4). The combination of the forecast long-term Government of Canada bond yield of 4.5% and a utility bond yield spread of 1.65% equates to a utility cost of debt of 6.15%. The resulting utility risk premium over a utility bond yield is 3.7% and the corresponding cost of equity, similar to the two independent variable approach, is 9.9% (Schedule 13, page 2 of 4).

4.d. Three-Stage DCF-Based Equity Risk Premium Test and Results

The reliability of the relationships estimated using the constant growth model was tested using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix C. The use of the three-stage model, which assumes that, in the long run, earnings growth for the utility sample will converge to the long-term rate of growth in the economy, effectively lessens the volatility of the monthly growth rates utilized in the analysis.[81]

Using monthly three-stage estimates of the DCF cost of equity, the average equity risk premium above long-term Treasury bond yields was 4.9% at an average long-term Treasury bond yield of 5.3% (Schedule 13, page 3 of 4). With three-stage DCF cost of equity estimates, the single independent variable regression analysis indicates that, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 71 basis points. The two independent variable (long-term government bond yields and utility/government bond yield spreads) showed that the utility equity risk premium increased or decreased by approximately 50 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately seven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 13, page 4 of 4).[82]

The indicated utility equity risk premiums and costs of equity based on the three-stage DCF model are summarized in the Table below.

Table 18

Regression Model	Long-term Government Bond Yield	Utility/ Government Bond Yield Spread	Equity Risk Premium	Cost of Equity
Single Independent Variable	4.5%	N/A	5.5%	10.0%
Two Independent Variables	4.5%	1.65%	5.1%	9.6%

[81] The standard deviation of the sample average monthly I/B/E/S growth rates is approximately 1.2; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.5.

[82] When the two independent variables were collapsed into a single independent variable, the long-term A-rated utility bond yield and the equity risk premium was measured as the DCF cost of equity minus the corresponding A-rated utility bond yield, the resulting relationship was:

Equity Risk Premium Over Baa-Rated Utility Bond Yield = 6.1% - 0.43 Baa-Rated Utility Bond Yield

At a Baa-rated utility bond yield of 6.15%, the indicated equity risk premium over the utility bond yield is 3.5% and the utility cost of equity is 9.6% (Schedule 13, page 4 of 4).

As an alternative test of the relationships, quarterly ROEs allowed for U.S. utilities were used as a proxy for the utility cost of equity to test the sensitivity of the utility cost of equity to changes in long-term government bond yields and utility/government bond yield spreads. 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.

Initially, the risk premiums indicated by the quarterly allowed ROEs from 1995 to 2010 were regressed against long-term Treasury bond yields lagged by six months.[83] The result indicated that the utility equity risk premium increased or decreased by approximately 60 basis points for every one percentage point decrease or increase in long-term government bond yields. When long-term Baa-rated utility/government bond yield spreads were added as a second independent variable, the analysis indicated that (1) the utility equity risk premium increased (decreased) by approximately 50% of the decrease (increase) in long-term Treasury bond yields; and (2) the risk premiums increased or decreased by approximately 20 basis points for every one percentage point increase or decrease in the long-term Baa-rated utility/government bond yield spread (Schedule 14, page 2 of 2).[84] At a forecast long-term Canada bond yield of 4.5% and a utility bond yield spread of 1.65%, the allowed ROE analysis indicates a utility risk premium of 5.9% and a cost of equity of 10.4%.

[83] The government bond yields and the spread variables 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.

[84] The regression is:

7.90 - 0.52 x 6 Months Lagged 30 Year Treasury Yield + 0.19 x 6 Months Lagged Spread

Collapsing the two independent variables into a single variable, long-term Baa-rated bond yields, and regressing those yields against the risk premiums indicated by the quarterly allowed ROEs, the analysis indicated that the risk premiums over utility bond yields have decreased (increased) by approximately 59 basis points for every one percentage point increase (decrease) in the Baa-rated utility bond yield.

4.e. DCF-Based Equity Risk Premium Test Results

The Table below summarizes the relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads for the various models and the resulting equity risk premiums and costs of equity at a forecast long-term Canada bond yield of 4.5% and a long-term utility/government bond yield spread of 1.65%.

Table 19

	Coefficients		**Equity Risk Premium**	**Cost of Equity**
	Government Bond	**Bond Yield Spread**		
DCF Constant Growth				
Single Variable	-1.25	n/a	6.0%	10.5%
Two Variable	-0.92	1.16	5.4%	9.9%
DCF Three-Stage Growth				
Single Variable	-0.71	n/a	5.5%	10.0%
Two Variable	-0.50	0.72	5.1%	9.6%
Allowed ROEs				
Single Variable	-0.58	n/a	6.0%	10.5%
Two Variable	-0.52	0.19	5.9%	10.4%

Note: "Single Variable" refers to the regression analysis applied only to the long-term government bond yield and "Two Variable" refers to the addition of the spread variable to the regression analysis.

While the indicated sensitivities of the models to changes in long-term government bond yields vary, they support the conclusion that the utility cost of equity does not vary with (or track) long-term government bond yields to the extent that has frequently been assumed.

Specifically, the analysis demonstrates that the utility cost of equity is materially less sensitive to long-term government bond yields than has been assumed by the automatic ROE adjustment formulas previously relied upon (e.g., AUC, BCUC, National Energy Board (NEB), OEB), and in some cases continue to be relied upon (Newfoundland and Labrador PUB and Régie de l'énergie) by regulators in Canada. Those formulas assume that the utility cost of equity increases/decreases by 75-80 basis points for every one percentage increase/decrease in the long-term Government of Canada bond yield. By comparison the two-variable three stage model indicates that the utility cost of equity increases/decreases by only 50 basis points for every one percentage point increase/decrease in long-term Government bond yields.

I have not given any explicit weight to the allowed ROE analysis in deriving an estimate of the utility cost of equity from the DCF-based risk premium test. However, that analysis supports provides further support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been frequently assumed.

Given the incongruous results of the single variable DCF constant growth model, my DCF-based risk premium estimates focus on the two-variable constant growth model and the three-stage model results. These three models indicate that the utility equity risk premiums and returns on equity at a long-term Canada bond yield of 4.5% and a utility/government bond yield spread of 1.65% are, respectively, approximately 5.0% to 5.5% and 9.5% to 10.0%.

5. Historic Utility Equity Risk Premium Test

5.a. Overview

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking equity risk premium for a benchmark utility. Similar to the DCF-based risk premium test, this test estimates the cost of equity for regulated companies directly by reference to return data for regulated companies. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

5.b. Historic Returns and Risk Premiums

As shown in Table 20 below, over the longest term available (1956-2010),[85] the average achieved utility (gas and electric combined) equity risk premiums in Canada were 4.5% and 4.8% in relation to total and income returns for long-term Government of Canada bonds

[85] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.

respectively.[86] For U.S. electric utilities, the corresponding 1947-2010 average achieved risk premiums were 4.5% and 4.9%. For U.S. gas utilities, the corresponding average historic equity risk premiums in relation to total and income returns on bonds over the entire post-World War II period (1947-2010) were 5.6% and 5.9% respectively.

Table 20

				Risk Premium Over:	
	Utility Equity Returns	**Bond Total Returns**	**Bond Income Returns**	**Bond Total Returns**	**Bond Income Returns**
Canadian Utilities	12.2%	7.7%	7.4%	4.5%	4.8%
U.S. Electric Utilities	10.8%	6.3%	5.9%	4.5%	4.9%
U.S. Gas Utilities	11.8%	6.3%	5.9%	5.6%	5.9%

Source: Schedule 15.

5.c. Trends in Equity Returns and Bond Returns

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat (Schedule 15, pages 2 and 3 of 3). The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.0-12.0%. However, the achieved government bond returns (total and income) in Canada over the period of analysis, at 7.4% to 7.7%, were materially higher than the yields on long-term Canada bonds forecast for both the near-term (4.5%) and over the longer-term (5.25%). With no change in the utility equity market return (i.e., a utility equity market return of 11.0% to 12.0%), the indicated utility risk premium at the forecast 2012 long Canada bond yield of 4.5% is approximately 6.5%. At the long-range expected return on long-term Canada bonds of 5.25%, the indicated utility equity risk premium is approximately 6.25%. Based on both estimates of the long-term Canada bond yield, the indicated utility risk premium is in the range of 6.25% to 6.5%.

[86] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2010.

An alternative way of interpreting the historical utility return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields demonstrated in the DCF-based equity risk premium analysis, including the analysis of allowed ROE. That analysis supports the conclusion that the utility equity risk premium changes by approximately 50% of the change in long-term government bond yields.

Table 21 below derives estimates of the utility equity risk premium at the 2012 forecast long-term Canada bond yield from the historical averages by applying the 50% sensitivity factor to the difference between the historical average bond income returns and the 4.5% Government of Canada bond yield forecast for 2012.

Table 21

		Canadian Utilities	**U.S. Electric Utilities**	**U.S Gas Utilities**
Equity Returns	(1)	12.2%	10.8%	11.8%
Bond Income Returns	(2)	7.4%	5.9%	5.9%
Risk Premium (RP)	(3) = (1) – (2)	4.8%	4.9%	5.9%
2012 Forecast Long-Term Canada Bond Yield (LCBY)	(4)	4.5%	4.5%	4.5%
Change in Bond Yield/Return	(5) = (4) – (2)	-2.9%	-1.4%	-1.4%
Change in Equity RP	(6) = – (5) X 50%	1.5%	0.7%	0.7%
Equity Risk Premium at 4.5% LCBY	(7) = (3) + (6)	6.25%	5.6%	6.6%

Source: Schedule 15.

At a forecast 2012 long-term Canada bond yield of 4.5% and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 5.5% to 6.5% (mid-point of 6.0%).

5.d. Historic Utility Equity Risk Premium Test Results

The two perspectives indicate a utility equity risk premium of approximately 6.0% to 6.5%. At the forecast 2012 long-term Canada bond yield of 4.5% and a utility risk premium of 6.0% to 6.5%, the indicated utility cost of equity is approximately 10.5% to 11.0%.

6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility costs of equity based on the three equity risk premium methodologies are as follows:

Table 22

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	9.5%
DCF-Based	9.5%-10.0%
Historic Utility	10.5%-11.0%

The three equity risk premium tests indicate a utility cost of equity of approximately 10.0%.

D. DISCOUNTED CASH FLOW TEST[87]

1. Conceptual Underpinnings

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. The DCF model is a positive model; that is, it deals with “what is” as opposed to “what should be”. The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity model indirectly. The DCF model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.

[87] See Appendix C for a more detailed discussion.

In simplest terms, the DCF cost of equity 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[88]

$\mathbf{P_o}$ = current price

$\mathbf{g}$ = expected growth in dividends

There are multiple versions of the discounted cash flow model available to estimate the investor's required return on equity, including the constant growth model and multiple period models to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

2. <u>Application of the DCF Test</u>

2.a. <u>DCF Models</u>

To estimate the DCF cost of equity, both the constant growth model and a multiple stage (three-stage) model were used. In both cases, the discounted cash flow test was applied to a sample of U.S. electric utilities that are intended to serve as a proxy for NSPI, as well as to a sample of Canadian utilities.

2.b. <u>Growth Estimates</u>

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a

[88]Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.[89]

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. 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: I/B/E/S (First Call), Reuters, *Value Line* and Zacks. The second is an estimate of sustainable growth. The sustainable growth rate represents the growth in earnings that a utility can expect to achieve as a result of the ROE it is expected to earn and the proportion of the ROE it reinvests plus incremental earnings growth achievable as a result of external equity financing. The development of the sustainable growth rates is explained in detail in Appendix C.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. Three such tests are described in Appendix C. These tests indicate that the consensus of analysts' long-term earnings growth forecasts is not an upwardly biased estimate of investor expectations.

[89] In addition, any cost of equity estimate that relies on data for a single company only is subject to measurement error.

3. Results of the DCF Model

3.a. Results for the Sample of U.S. Electric Utilities

The two constant growth models applied to the U.S. electric utility sample indicate a cost of equity of approximately 9.3% to 9.8% (Schedules 16 and 17).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy. The three-stage DCF model is fully described in Appendix C. The three-stage model applied to the sample of U.S. electric utilities indicates a cost of equity of approximately 9.5% (Schedule 18).

3.b. Results for the Sample of Canadian Utilities

The constant growth and three-stage DCF models were also applied to a sample of Canadian utilities with publicly-traded shares and for which long-term growth rate forecasts were available from I/B/E/S (First Call) and Bloomberg.[90] The application of the constant growth model to a sample of five Canadian utilities indicated a cost of equity in the range of 9.5% to 10.5% (mid-point of 10.0%). The cost of equity developed using the three-stage model indicates a cost of equity in the range of 8.5% to 8.8% (mid-point of 8.7%) (Schedules 19 and 20).

3.c. DCF Cost of Equity

The Table below summarizes the results of the DCF models applied to both the U.S. electric utility sample and the Canadian utility sample.

[90] Long-term earnings growth forecasts were available from each of these two sources for Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. There are no widely available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth.

Table 23

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Electric Utilities	9.8%	9.3%	9.5%
Canadian Utilities	10.0%	N/A	8.7%

Source: Schedules 16-20.

The two DCF models applied to the sample of U.S. electric utilities and to the sample of Canadian utilities support a cost of equity for NSPI of approximately 9.5%.

E. ALLOWANCE FOR FINANCING FLEXIBILITY[91]

The equity risk premium tests (Section VII.C) and discounted cash flow tests (Section VII.D) indicate a "bare-bones" cost of equity for NSPI in the range of 9.5% (Discounted Cash Flow) to 10.0% (Equity Risk Premium), or approximately 9.75%. The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the "fairness" principle.

In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite averaged 2.1 times from 1995-2010; the corresponding average market/book ratio of the S&P 500 was 3.1 times.[92]

[91] See Appendix D for a more complete discussion.
[92] The market to book ratio of the S&P 500 includes the Utilities. The market to book ratio of the S&P Industrials alone has been higher.

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[93] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard.

The cost of capital, as determined in the capital markets, is derived from market value capital structures. The cost of equity has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the corresponding book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure that the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the "bare bones" cost of equity of approximately 140 basis points (See Appendix D).

[93] Based on the DCF model as shown in Appendix D, footnote 2.

A reasonable adjustment for financing flexibility to the “bare bones” cost of equity estimated solely by reference to market-based tests (that is, without reference to the comparable earnings test) would be the mid-point of the indicated range of 50 to 140 basis points. The addition of an allowance for financing flexibility of 50 to 140 basis points to the “bare-bones” return on equity estimate of 9.75% for NSPI, derived from the equity risk premium and DCF tests, results in an estimate of the fair return on equity for 2012 of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.[94]

F. FAIR ROE FOR NSPI

The fair return for NSPI for 2012 is 10.7% (mid-point of a range of 10.25% to 11.2%), based on the following:

(1) A forecast long-term Government of Canada bond yield of 4.5% for 2012;

(2) A “bare-bones” cost of equity of 10.0% based on the equity risk premium tests;

(3) A “bare-bones” cost of equity of 9.5% based on the application of the discounted cash flow tests;

(4) A “bare-bones” cost of equity for NSPI of 9.75%, based on both the equity risk premium tests and discounted cash flow tests;

(5) An allowance for financing flexibility in a range of 0.50% to 1.4%;

(6) A fair return on equity of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.

[94] The recommended ROE compares to an average of the most recent allowed ROEs for the U.S. electric utility sample of approximately 10.5%, based on decisions rendered between 2007 and 2010; see Appendix B.

OPINION

ON

CAPITAL STRUCTURE
AND
RETURN ON EQUITY

FOR

NOVA SCOTIA POWER INC.

APPENDICES

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

April 2011

APPENDICES

APPENDIX A

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F + \beta(R_M - R_F),}$$

Where:

$\mathbf{R_F}$ = risk-free rate

$\boldsymbol{\beta}$ = covariability of the security with the market (M)

$\mathbf{R_M}$ = return on the market.

The model is based on restrictive assumptions, including:

a. Perfect, or efficient, markets exist where,

(1) each investor assumes he has no effect on security prices;

(2) there are no taxes or transaction costs;

(3) all assets are publicly traded and perfectly divisible;

(4) there are no constraints on short-sales; and,

(5) the same risk-free rate applies to both borrowing and lending.

b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance }(R_E, R_M)}{\text{Variance }(R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

2. RISK-FREE RATE

a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

(1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government was in a surplus position from 1997/1998 to 2007/2008 (ten years), which reduced its financing requirements.[1] In 2008/2009, despite a budget deficit, the federal debt/GDP ratio stood at 29%, its lowest level since 1980/81, and well below the 1995/1996 peak of 68%. In 2009, Government of Canada bonds accounted for approximately one-quarter of total Canadian dollar bonds outstanding[2], compared to almost half in 1996.[3] However, the demand for long-term government securities by institutions that are "buy and hold" investors and that match the duration of their assets and liabilities (e.g., pension funds and insurance companies) has not declined. Thus, there is a potential for the prices of

[1] Following a budget deficit of $55.6 billion in fiscal year 2009/2010 and an anticipated deficit of $40.5 billion 2010/2011, the Federal government's 2011 Budget anticipates budget deficits for all fiscal years through 2014/2015. A small surplus ($4.2 billion) is projected for 2015/2016. Federal debt to GDP is expected to peak at approximately 35% in 2011/12, declining to its pre-recession level in 2015/2016. (Department of Finance, *Next Phase of Canada's Economic Action Plan*, March 23, 2011)
[2] Includes provincial, municipal, corporate, foreign issuer, and term securitization bonds.
[3] Statistics Canada, www.statcan.gc.ca

long-term government bonds to incorporate a scarcity premium reflecting an imbalance between demand and supply.

(2) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, the wake of the subprime mortgage crisis commencing in late 2007, and the sovereign debt crisis in Europe, investors shifted to the safe haven of government securities perceived as default-free, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM, which relies heavily on long-term average achieved equity risk premiums, captures the lower government bond yields, but not the corresponding increase in the equity risk premium.

(3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. Changes in the risk of the "risk-free" security introduce further complexity to the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

c. The radical change in Canada's fiscal performance since the mid-1990s contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada measured using total bond returns were squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to the historical total returns on those securities indicate that the historical returns on long-term Government of Canada bonds overstate the forward looking risk-free rate. The estimate of the equity market risk premium using historical data as a point of departure needs to recognize the much higher government bond returns historically than the forecast risk-free rate.

d. Total returns on government bonds include capital gains and losses resulting from changes in interest rates over time. The income return on government bonds, in contrast, reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.

3. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, Boston: Irwin/McGraw Hill, 2006 (p. 151), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for estimation of the cost of equity is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

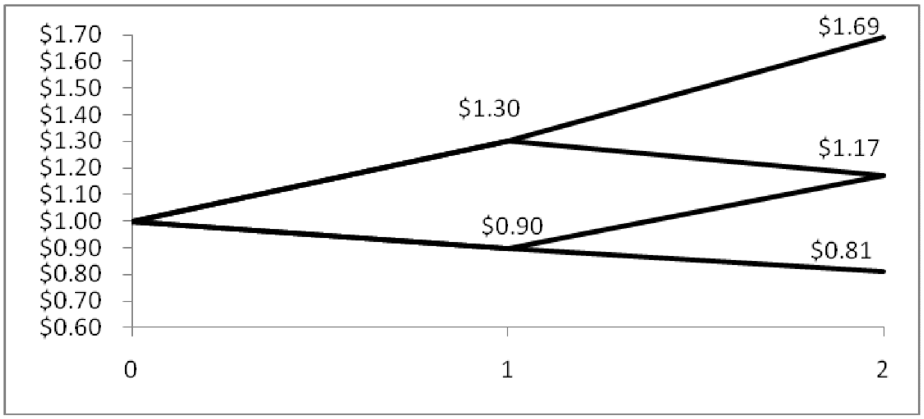
> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2010,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-3

Graph 5-3
Growth of Wealth Example



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30) \times (1-0.10)]^{½} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x $1.69)	=	$0.4225
+	(0.50 x $1.17)	=	$0.5850
+	(0.25 x $0.81)	=	$0.2025
	Total		$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \times (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

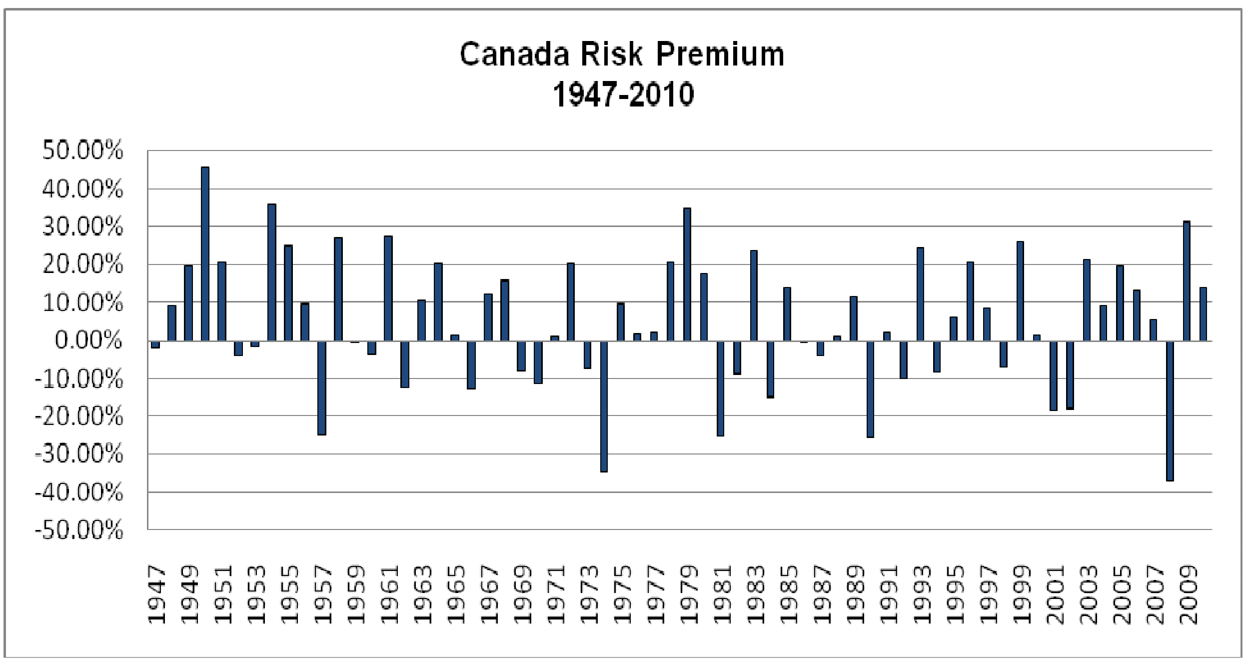
$$\$1 \times (1+0.082)^2 = \$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historical post-World War II annual risk premiums (measured as the equity market return less the corresponding year's long-term government bond income return). The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[4]

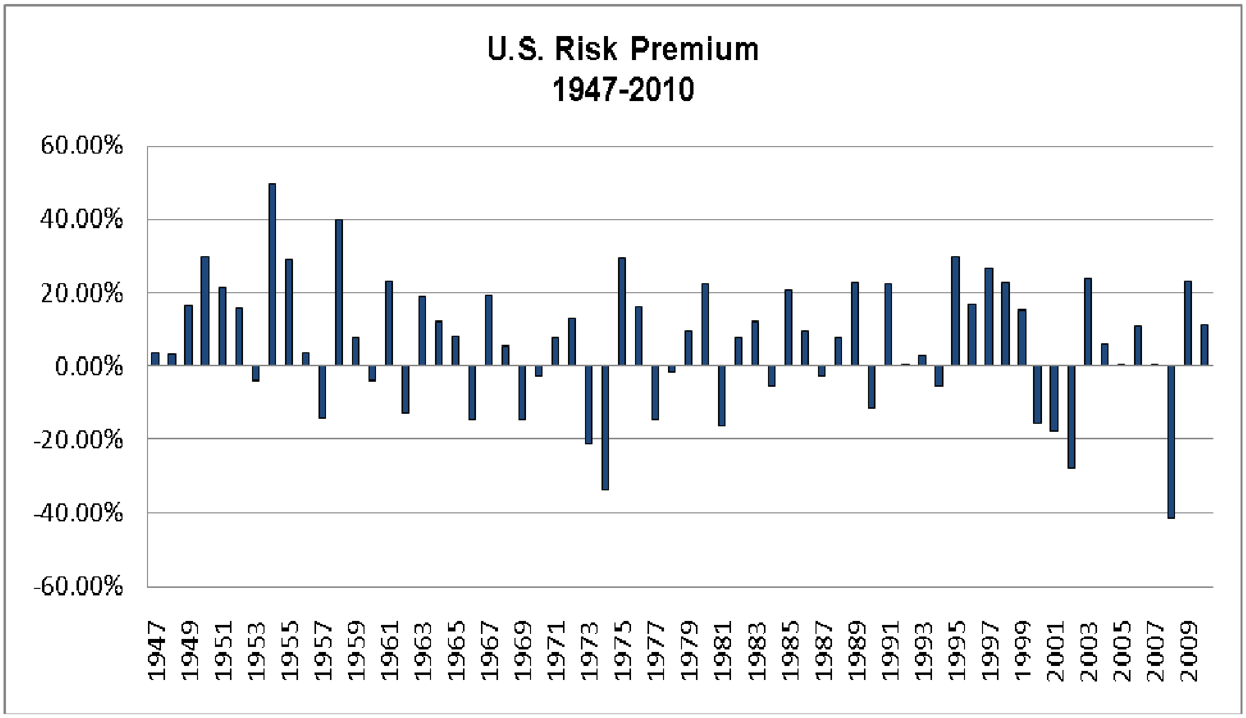
Chart A - 1



Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2009*, and *TSX Review*.

[4] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlations between the current year's risk premium (equity market return less bond income return) and that of the prior year for the period 1947-2010 are -0.045 for Canada and -0.03 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Chart A - 2



Source: www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2010 Yearbook*, and www.standardandpoors.com .

4. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[5] The next largest sector, financial

[5] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table A-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table A - 1

	1980	**2000**
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2007, the energy and materials (largely mining) sectors accounted for close to 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 75% of the total market value of the composite. Despite the sharp decline in commodity prices in 2008-2009 and the fall-out of the sub-prime mortgage crisis, the same three sectors represented almost 80% of the value of the S&P/TSX Composite Index at the end of 2010.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at year-end 2010 demonstrates the difference.

Table A - 2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.5%	10.6%
Consumer Staples	2.5%	10.5%
Energy	26.7%	11.9%
Financials	27.9%	16.3%
Health Care	0.8%	10.9%
Industrials	5.5%	10.9%
Information Technology	2.4%	18.7%
Materials	24.1%	3.7%
Telecommunication Services	4.0%	3.2%
Utilities	1.7%	3.3%

Source: *TSX Review*, December 2010 and www.standardandpoors.com (January 5, 2011).

Even within the remaining areas of the Canadian market (the less than 25% accounted for by the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index as compared to the largest stock in the S&P 500 at that time (General Electric) which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. At the end of December 2010, the largest twenty stocks in the Composite Index accounted for approximately 50% of the total market capitalization of the S&P/TSX Composite Index. Of the twenty, six (19% of Composite Index market capitalization) were financial and eleven (25% of Composite Index market capitalization) were resource (energy and mining) companies.[6] The undue influence of a small

[6] By comparison, the largest 20 stocks in the S&P 500 accounted for less than 30% of the total index market capitalization, with no single industry represented among the top 20 stocks accounting for more than 10% of the total market capitalization of the index.

number of stocks requires caution in drawing conclusions from the history of the Composite Index regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some of these concerns when they overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2010 there were 245 companies in the S&P/TSX Composite Index.

The addition of income trusts at the end of 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. From 1998 (the first year for which returns were reported) to 2005, the annual compound total return for the S&P/TSX Capped Income Trust Index was 19%, compared to 8.5% for the S&P/TSX Composite Index.[7] As income trusts significantly outperformed "conventional" equities, their exclusion from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.[8]

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[9] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[10] which supported the removal of the cap.[11] At that time, the *Globe and Mail* reported

[7] The annual compound total return for the S&P/TSX Capped Income Trust Index over the 1998-2010 period averaged 14.1%, compared to 7.7% for the S&P/TSX Composite Index.
[8] With the change to the income tax treatment of income trusts announced in October 2006 (effective January 1, 2011), most of the income trusts in the S&P/TSX Composite Index have converted back to conventional corporations.
[9] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.
[10] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.
[11] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

that the removal of the foreign content cap was expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[12] The Foreign Property Rule was eliminated in 2005.

Effectively, the combination of mediocre returns and small size of the Canadian market relative to the total global market put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. From this perspective, historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases have declined from their 2007 peaks, in 2010 they exceeded $500 billion of which over 70% were U.S. stocks.[13] In mid-2010, although the total percentage of foreign assets in trusteed pension funds was less than 30%, the percentage of foreign equity to total equity was close to 50%.[14, 15] In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Close to 40% of Canadian portfolio investment in foreign equities at the end of 2009 was in the U.S.[16]

[12] Rob Carrick, *Finance: Your Bottom Line*, www.globeandmail.com, February 23, 2005.
[13] Statistics Canada, *International Transactions in Securities*, *December 2010*, February 2011.
[14] Based on market value. Statistics Canada, Table 280-0003, data through September 2010, available March 2011.
[15] Pension funds have increasingly been investing in infrastructure assets outside of Canada. With specific respect to utility investments, in early 2009 a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board completed the acquisition of Puget Energy, an electric and gas utility serving northern Washington State. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.1% on a 46% common equity ratio, adopted in April 2010.
[16] Statistics Canada, *Canada's International Investment Position – Third quarter 2010,* January 2011. The U.S. portion of Canadian direct investment abroad at the end of 2009 was 44%.

5. TRENDS IN PRICE/EARNINGS RATIOS

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[17] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[18] From 11.7 times in 1988, the P/E ratio gradually rose, peaking at over 46 times in late 2001. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[19] By mid-2006, the P/E ratio had fallen to 17 times based on reported earnings and 15.5 times based on operating earnings.

As the market advanced from 2006 to late 2007, the P/E ratio expanded; when the S&P 500 was at its pre-crisis peak, the P/E ratio reached 19 times based on reported earnings (17 times based on operating earnings). As both the market and reported earnings collapsed during the financial crisis, the P/E ratio based on reported earnings soared to above 100 times during the second quarter of 2009. Based on operating earnings, the increase was much less extreme; the P/E ratio based on operating earnings reached 27 times during third quarter 2009. With recovery in both

[17] Price to trailing earnings.
[18] The average P/E ratio from 1947-1988 was 13 times.
[19] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

earnings and the equity market, the P/E ratio fell. At the end of December 2010, the P/E ratio of the S&P 500 was 15.0 times (based on estimated 2010 operating earnings), compared to the long-term (1936-2010) average of approximately 16 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1936 (the first year for which P/E ratios are readily available) and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.3% from 1936-1988. The corresponding average return from 1936-2010 was 12.0%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1936-2010 period than over the 1936-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.5% over the entire 1947-2010 period. In other words, the increase in P/E ratios during the 1990s did not result in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable.

A review of equity returns in Canada indicates similar results. The 1936-1988 arithmetic average return for the Canadian equity market was 11.8%, higher than the average 1936-2010 return of 11.4%. Similarly, the 1947-1988 equity market return of 12.9% was higher than the 1947-2010 return of 12.1%. There is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward.

6. RELATIVE RISK ADJUSTMENT

a. Beta

The body of evidence on CAPM leads to the conclusion that, while betas[20] do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French stated in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

---

[20] The beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

Where: R_E = Return on the individual stock or portfolio of stocks and R_M is the return on the equity market.

Alternatively, the beta can be expressed as:

Standard Deviation of R_E / Standard Deviation of R_M X Correlation Coefficient (ρ)

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

The Fama French study found that the relationship between beta and average return is much flatter than the CAPM would predict. Specifically, based on analysis covering 1928 to 2003 for the U.S. market, they showed that the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return.[21]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate

[21] Fama and French developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM. The additional factors are size and book to market.

> were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[22]

b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table A - 3

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 10, page 1 of 2.

[22] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table A-3 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2010, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,[23] and (c) the 10-year period ending 2010.

That analysis showed the following:

Table A - 4

Returns Measured Over:	Coefficient on Beta	R^2
1988-2010	-.004	26%
1988-1997	-.017	1%
2001-2010	-.125	31%

Source: Schedule 10, page 2 of 2.

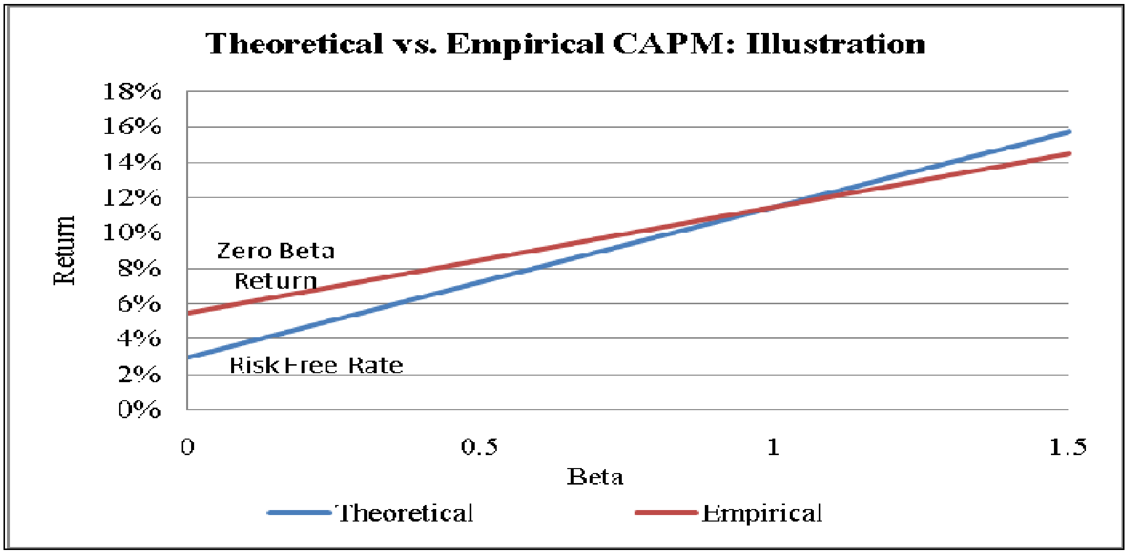
These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship.

The theoretical CAPM posits a market security line with an intercept equal to a “risk-free rate” and returns for risky securities proportional to their beta. Empirical studies point to a higher intercept and a flatter market security line than the theoretical model posits. In other words, a “zero beta” stock has a higher return than the risk-free rate and low (high)

[23] The use of this sub-period was intended to eliminate of the impacts of any anomalous market behavior during the technology “bubble and bust”, which occurred mainly from 1999 through mid-2002.

beta stocks have achieved higher returns than their "raw" betas imply, as illustrated in Chart A-3, below.

Chart A - 3



The empirical studies that have tested the CAPM typically rely on a short-term government bond return. To some extent, the application of the CAPM using a long-term government bond yield rather than a short-term instrument adjusts for the tendency of the CAPM to understate (overstate) returns for low (high) beta stocks. The use of a long-term risk-free rate rather than a short-term rate shifts the intercept of the market security line upward and decreases the slope of the line. The implication of this shift for a stock with a "raw" beta of 1.0 can be illustrated as follows:

In Canada, the spread between the three-month Treasury bill and the long-term government bond yield historically has been approximately 1.3%. If the three-month Treasury bill rate is 4.0%, the market return is 11.5% and the "raw" beta of a utility portfolio is 0.50, using the short-term rate as the risk-free rate produces a CAPM return of 7.75% (4.0% + 0.50 (11.5%-4.0%)). When a long-term Government of Canada bond yield 5.25% is used as the risk-free rate, the CAPM return is equal to 8.375% (5.25% + 0.50 (11.5%-5.25%)). Replacing the short-term Treasury bill rate with the long-term government bond yield adjusts the cost of equity of a stock with a 0.50 “raw” beta upward by 0.625 percentage points. Similarly, using the long-term government bond yield as the risk-free rate adjusts the cost of equity of a stock with a “raw” beta of 1.50 downward by 0.625 percentage points.

The indicated increase in returns for low beta stocks that is indicated by the replacement of the short-term rate with the long-term rate is well below the 2.8 percentage point difference between the actual and predicted return for the lowest beta portfolio that was identified in the Fama and French study referenced above.

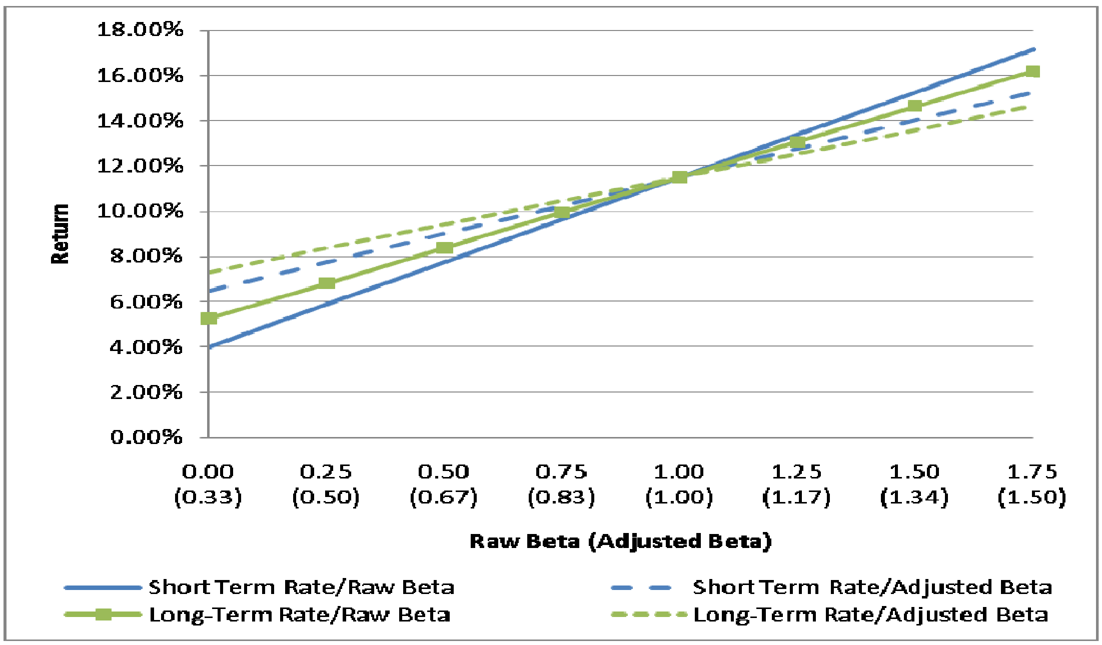
The use of adjusted betas in place of “raw” betas provides a further means of correcting for betas’ under (over) prediction of returns for low (high) beta stocks. Reliance on adjusted betas initially arose in response to the empirically documented failure of betas calculated from one period to be good predictors of betas calculated in a subsequent period. The standard adjustment formula for beta adjusts the “raw” beta toward the market mean beta of 1.0 as follows:

Adjusted beta = “Raw Beta” X (2/3) + Market Mean Beta of 1.0 X (1/3)

While the standard beta adjustment formula was initially adopted to account for the observed tendency of betas generally to trend toward the market mean beta of 1.0, effectively its application acts to further adjust for the under and over prediction of returns of low and high beta stocks by the “classic” single variable CAPM. Reliance on betas adjusted using the formula set out above in conjunction with a long-term Government of Canada bond yield as the risk-free rate results in (1) a market security line intercept that lies above the long-term government bond yield and (2) a further flattening of the slope of the line. The implications are higher predicted returns for stocks with betas below the market mean beta of 1.0 and lower predicted returns for stocks with betas above the market mean beta of 1.0.

Chart A-4 below illustrates the differences in predicted returns arising from using (1) a short-term risk-free rate and a “raw” beta; (2) a long-term risk-free rate and a “raw” beta; and (3) a long-term risk-free rate and an adjusted beta. The key implications of using a long-term risk-free rate and an adjusted beta are: (1) a “zero beta” stock, i.e., one whose stock price movements are uncorrelated with those of the market portfolio would be expected to achieve a higher return than achievable by investing in government bonds; and (2) the trade-off between risk and return across the beta risk spectrum is less pronounced than suggested by either the short-term risk-free rate/“raw” beta or the long-term risk-free rate/ “raw” beta approach.

Chart A- 4



Using the standard beta adjustment formula set out above moves a “raw” utility beta of 0.50 to 0.67. With the same inputs for market return (11.5%) and long-term government bond yield (5.25%) as in the previous example, the use of an adjusted beta rather than a “raw” beta increases the indicated utility equity return by slightly more than 1.0%. The total adjustment to the utility equity return of approximately 1.65% (0.625% for the difference between the long-term and short-term risk-free rates and 1.03% for the difference between the adjusted and “raw” betas) is materially lower than the total 2.8

percentage point under-prediction for the lowest beta portfolio identified in the Fama and French study.

APPENDIX B

SELECTION OF U.S. ELECTRIC UTILITY SAMPLE

For the estimation of an ROE applicable to NSPI using the Discounted Cash Flow-Based Equity Risk Premium Test and the Discounted Cash Flow Test (see Appendix C), a sample of U.S. electric utilities was selected.

The sample is comprised of all publicly-traded U.S. electric utilities satisfying the following criteria:

1. Classified by *Edison Electric Institute 2009 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. Analysts' long-term earnings forecasts available from three of the four following sources: I/B/E/S (First Call), Reuters, *Value Line* and Zacks;

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

5. Not being acquired or involved in a merger;

6. Paid dividends quarterly from 1995 to 2010, or since the initiation of trading of common shares.

The fifteen utilities that met these criteria are:

ALLETE Inc.
Alliant Energy Corp.
Dominion Resources Inc.
Duke Energy Corp.
IDACORP Inc.
NextEra Energy Inc.
OGE Energy Corp.
Portland General Electric Co.
Progress Energy
SCANA Corp.
Sempra Energy
Southern Co.
Vectren Corp.
Wisconsin Energy Corp.
Xcel Energy Inc.

Utility-specific information is found on pages B-3 to B-36 of this Appendix and on Schedule 12.

Attachment 1 to Appendix B

ALLETE Inc.

Operating Characteristics:	
Operations:	Principal subsidiaries are regulated utilities: *Minnesota Power(MP)*: electric distribution in northeastern Minnesota *Superior Water Light & Power(SWL&P)*: electric, natural gas and water service in northwestern Wisconsin Have an investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in Wisconsin, Michigan, Minnesota and Illinois Unregulated subsidiaries represent 9% of assets; include coal mining operations (consumed primarily by two electric cooperatives, Minnkota & Square Butte, from whom MP purchases capacity and energy under contracts to 2026), real estate, emerging technology investments, and a small amount of non-rate base generation.
Total Assets:	$2,393 million
Percentage of Assets in Gas and Electric Operations:	Approximately 91% of assets in regulated
State(s) of Utility Operations:	Northeastern Minnesota and northwestern Wisconsin
Number of Customers:	MP – 146,000 electric customers and 16 municipalities in Minnesota SWL&P – 15,000 electric, 12,000 gas, and 10,000 water customers in Wisconsin
Customers by Type:	see below

Regulated Utility Sales by Customer Type	2009 % of Kwh Sold	2010 % of Kwh Sold
Residential	10%	9%
Commercial	12%	11%
Industrial	37%	52%
Municipals	8%	7%
Other Power Suppliers	33%	21%

(ALE cont'd)

Regulatory Environment:	
Test Year:	Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	**Electric:** MP: 10.38% (Nov 2010) SWL&P: 10.9% (Dec 2010) **Gas:** SWL&P: 10.9% (Dec 2010)
Equity Ratio (Latest Allowed):	MP: 54.3% (Dec 2010) SWL&P: 54.9% (Dec 2010)
Earnings Sharing:	n/a
Deferral Mechanisms:[i]	Deferral of certain expenses; pension and OPEB, Lost and unaccounted for gas mechanism. Rate riders provided for annual recovery of specific costs (transmission expenditures, emission reduction, conservation, environmental and renewable) as of 2010 rate case, moved to PP&E in rate base to be recovered in base rates.
Fuel/Gas Cost Recovery:	MN: fuel adjustment clause that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator Day 2 costs. WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers.
RRA Regulatory Climate:[ii]	Average 2 (MI) Above Average 2 (WI)
Moody's Rating Methodology:[iii] Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Ba Financial Strength (40%): A
S&P's Regulatory Comment	"Regulatory support for various environmental upgrades should help bolster financial measures during construction."

Alliant Energy Corp.

Operating Characteristics:	
Operations:	Principal subsidiaries are regulated utilities: *Interstate Power and Light(IPL)*: electric generation and distribution, and gas distribution in Iowa and Minnesota; 77% 2009 revenues electric, 18% 2009 revenues gas *Wisconsin Power and Light(WPL)*: electric generation and distribution, and gas distribution in Wisconsin; 84% 2009 revenues electric, 16% 2009 revenues gas IPL completed sale of electric transmission assets in IA, MN and IL to ITC in 2007; WPL transferred transmission assets to ATC in 2001 in exchange for ownership interest in ATC. IPL & WPL members in MISO a FERC-approved RTO. Unregulated subsidiaries represent 5% of assets; include RMT (environmental, consulting, engineering and renewable energy services), rail and barge transportation services, and non-regulated generation.
Total Assets:	$9,036 million.
Percentage of Assets in Gas and Electric Operations:	Approximately 95% of assets in utility operations.
State(s) of Utility Operations:	Iowa, southern Minnesota, and southern and central Wisconsin
Number of Customers:	IPL – 525,000 electric customers and 234,000 gas customers in Iowa and southern Minnesota WPL– 454,000 electric and 178,000 gas customers in Wisconsin
Customers by Type:	see below

Customer Type	2009 % of Revenues	2009% Sales MWh
Residential	35%	25%
Commercial	22%	20%
Industrial	29%	36%
Wholesale	8%	11%
Bulk Power & Other	6%	9%

(LNT cont'd)

Regulatory Environment:	
Test Year:	Historical in Iowa Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	**Electric:** IPL (Iowa): 10.44% (Dec 2010) reduced to 10.0% due to automatic rider for transmission cost recovery approved January 2011 as part of same case. IPL (Minnesota): 10.39% (Mar 2006) WPL (Wisconsin): 10.40% (Dec 2009) **Gas:** IPL (Iowa): 10.40% (Oct 2005) WPL (Wisconsin): 10.40% (Dec 2009)
Equity Ratio (Latest Allowed):	**Electric:** IPL (Iowa): 44.24% (Dec 2010) IPL (Minnesota): 49.10% (Mar 2006) WPL(Wisconsin): 50.38% (Dec 2009) **Gas:** IPL (Iowa): 49.35% (Oct 2005) WPL (Wisconsin): 50.38% (Dec 2009)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension and OPEB, Lost and unaccounted for gas mechanism, Energy Efficiency Cost Recovery (EECR), In December 2010, IPL was authorized to implement a pilot transmission cost recovery mechanism (automatic rider) for a three-year term. The rider was implemented in conjunction with a 3-year base rate freeze and reduction in allowed ROE of 0.40%. A similar transmission cost rider was proposed in Minnesota (Jan 2010)
Fuel/Gas Cost Recovery:	IA: retail electric and gas tariffs contain automatic adjustment clause modified monthly. WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers.
RRA Regulatory Climate:	Above Average 3 (IA) Average 2 (MN) Above Average 2 (WI)

(LNT cont'd)

Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A/Baa Financial Strength (40%): A
S&P's Regulatory Comment	"More credit supportive regulatory jurisdictions"

Dominion Resources Inc.

Operating Characteristics:	
Operations:	*Dominion Virginia Power (DVP)* – regulated electric distribution and transmission; non-regulated retail energy marketing (17% Earnings 2009) *Dominion Generation* Regulated generation at both Dominion and Virginia Power and Merchant Fleet generation (Dominion only) (59% Earnings 2009) *Dominion Energy* – regulated gas transmission, distribution, and storage, LNG import and storage, gas exploration and production (sold 2010). (24% Earnings 2009)
Total Assets:	$42,554 million
Percentage of Assets in Gas and Electric Operations:	Approximately 47% of assets in electric and gas operations, and 44% in generation.
State(s) of Utility Operations:	Virginia, northeastern North Carolina, Ohio, Pennsylvania, and West Virginia.
Number of Customers:	Approximately 4 million customers in 2009 of which 2.4 million in Virginia and North Carolina, 1.2 million in Ohio, 358,000 in Pennsylvania (sold 2010)
Customers by Type:	**DVP 2009** / **Retail Electric Sales** / **Customers By Type** Residential 47% 89% Commercial 34% 10% Industrial 8% <1% Governmental 11% 1%
Regulatory Environment:	
Test Year:	NC, VA, WV: Historic with adjustments for known and measurable changes OH: Partial forecast PA: Forecast
Return on Equity (Latest Allowed):	**Electric:** 11.9% (2010 VA) 10.7% (2010 NC) **Gas:** 9.45% (2009 WV)
Equity Ratio (Latest Allowed):	**Electric:** 47.71% (2010 VA) 51.00% (2010 NC) **Gas:** 42.34% (2009 WV)
Earnings Sharing:	n/a

(D cont'd)

Deferral Mechanisms:	Rate adjustment for construction related financing costs related to two hybrid energy centers, rate rider for transmission related expenditures, Lost and unaccounted for gas mechanism,
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. The annual increase in rates related to the recovery of purchased power costs is limited to 2% of total retail revenues. VA: electric rates reset annually on the basis of projected usage and costs; any over- or under-accruals, reconciled through the following year's fuel factor. Purchased power energy and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor; capacity charges recovered through base rates. OH, PA & WV: gas cost recovery fully recovered. Purchased gas cost recovery filings generally cover prospective one, three, or twelve-month periods.
Sales and Weather Normalization:	In December 2008, Dominion East Ohio implemented a transition to a Straight Fixed Variable rate design.
RRA Regulatory Climate:	Above Average 3 (VA) Above Average 2 (NC) Average 1 (OH) Average 3 (WV and PA)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): Baa/Ba
S&P's Regulatory Comment	"benefits from low regulatory risk"

Duke Energy Corp.

Operating Characteristics:	
Operations:	*Utility* – generates, transmits, distributes and sells electricity in North Carolina, South Carolina, Ohio, Indiana, and Kentucky. Transports and sells natural gas in Ohio and Kentucky. *Commercial Power* – owns, operates, and manages power plants and engages in the wholesale marketing of electric power, fuel, and emission allowances. *International Energy* – owns, operates, and manages power generation facilities outside the U.S. *Other* – insurance and interest in communications.
Total Assets:	$57,040 million
Percentage of Assets in Gas and Electric Operations:	Approximately 75% of assets in regulated electric and gas operations.
State(s) of Utility Operations:	Electric utility operations in central and western North Carolina, western South Carolina, southwestern Ohio, central, north central, and southern Indiana, and northern Kentucky. Gas utility operations in southwestern Ohio and northern Kentucky.
Number of Customers:	4.0 million electric customers; 2.4 million in North and South Carolina, 685,000 in Ohio, 780,000 in Indiana, and 135,000 in Kentucky. 500,000 gas customers; 400,000 in Ohio and 100,000 in Kentucky.
Customers by Type:	**Customer Type** / **2009% Electric Revenue** Residential 42% Commercial 33% Industrial 18% Other 7%
Regulatory Environment:	
Test Year:	NC: Partial or fully forecast IN, KY, SC: Historic with adjustments for known and measurable changes OH: Partial forecast

(DUK cont'd)

Return on Equity (Latest Allowed):	**Electric:** 10.5% (2004 IN) 11.5% (1992 KY) 10.7% (2009 NC) 10.63% (2009 OH) 10.7% (2010 SC) **Gas:** 10.38% (2009 KY) 10.50% (2008 OH)
Equity Ratio (Latest Allowed):	**Electric:** 44.44% (2004 IN) 45.95% (1992 KY) 52.50% (2009 NC) 51.59% (2009 OH) 53.00% (2010 SC) **Gas:** 49.90% (2009 KY) 55.76% (2008 OH)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs (OH, KY), Catawba Nuclear Station and related environmental compliance costs (NC, SC), carbon storage costs (Indiana), Bad Debt Expense (OH), Lost and unaccounted for gas mechanism
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause SC: non-automatic electric fuel and purchased gas adjustment clauses OH: Electric: rate stabilization plan that allows for rate recognition of a portion of the increases in fuel prices, purchased power costs, and emission expenditures. Gas: gas cost recovery charge providing quarterly adjustments with an annual review/hearing. Charges may be revised in a subsequent three-month period for any under- or over-recoveries related to the collection of an earlier period. IN: Electric: adjustments for changes in fuel and purchased power (energy component only) costs every three months, following hearings. Recovers 100% of purchased power capacity/demand charges through a summer reliability tracking mechanism in place until next base rate proceeding. KY: Recover fuel and purchased power (energy only) costs through automatic fuel adjustment clauses. Adjusted monthly, based on actual costs for the second preceding month with an under/over-recovery mechanism

(DUK cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (NC) Above Average 3 (IN) Average 1 (SC, OH, KY)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"Regulatory risk is managed relatively well, aided in part by jurisdictions with credit-supportive regulatory environments"

IDACORP Inc.

Operating Characteristics:	
Operations:	*Utility Operations:* subsidiary Idaho Power is engaged in the generation, transmission, distribution, sale, and purchase of electric energy. *Non-Utility*: investments in affordable housing and operation of small hydroelectric generation projects.
Total Assets:	$4,238 million
Percentage of Assets in Gas and Electric Operations:	Approximately 96% of assets in electric operations.
State(s) of Utility Operations:	Idaho (95% of revenue) and eastern Oregon
Number of Customers:	490,000
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 45.8% Commercial 26.1% Industrial 15.8% Irrigation 12.3%
Regulatory Environment:	
Test Year:	ID: Historic with adjustments for known and measurable OR: Partial or fully forecast
Return on Equity (Latest Allowed):	10.5% (2009 ID) 10.18% (2010 OR)
Equity Ratio (Latest Allowed):	49.27% (2009 ID) 49.80% (2010 OR)
Earnings Sharing:	Idaho Power is operating under an earnings sharing mechanism under which incremental earnings in excess of a 10.5% ROE in any calendar year 2009-2011 are to be shared equally.
Deferral Mechanisms:	Energy Efficiency Rider
Fuel/Gas Cost Recovery:	Electric power supply cost mechanism which trues-up costs on an annual basis subject to a deadband within which 90/10 sharing of costs and benefits between customers and shareholders. Collection/refund of revenues limited to 100bp impact on last allowed ROE
Sales and Weather Normalization:	Operating on a pilot program through 2011 applicable to residential and small general service customers only designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy costs (decoupling)

(IDA cont'd)

RRA Regulatory Climate:	Average 2 (ID) Average 3 (OR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A/Baa Financial Strength (40%): Baa/Ba
S&P's Regulatory Comment	"Generally supportive state regulatory regime"

NextEra Energy Inc.

Operating Characteristics:	
Operations:	*Florida Power & Light (FPL)* – regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Florida. *NextEra Energy Resources* – owns, develops, constructs, manages, and operates electric-generating facilities. Provides full energy and capacity requirements services. Engages in power and gas marketing and trading activities.
Total Assets:	$46,950 million
Percentage of Assets in Gas and Electric Operations:	FPL accounts for approximately 57% of assets; NextEra Energy approximately 43% assets
State(s) of Utility Operations:	Florida
Number of Customers:	4.5 million
Customers by Type:	**Customer Type** / **2009 % of Sales (kwh)** Residential 51% Commercial 43% Industrial 3% Wholesale 1% Other 2%
Regulatory Environment:	
Test Year:	Full or partial forecast
Return on Equity (Latest Allowed):	10.0% (2010 FL)
Equity Ratio (Latest Allowed):	47.0% (2010 FL)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pre-construction costs and carrying charges on construction costs for new nuclear capacity and new solar generating facilities recovered through cost recovery clauses, Storm-recovery bonds including interest and bond issuance costs recovered through surcharge to retail customers, Deferral for pension expense
Fuel/Gas Cost Recovery:	Fuel and purchased power cost recovery clause provides recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel cost and energy purchases and sales. Hearings are held each November during which the PSC sets fuel factors for the next calendar year.

(NEE cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Average 1 (FL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	Although "Low regulatory risk in Florida" has been "shaken in recent years" as decisions have reflected "more intense political influence over the regulatory environment" the "Utility's actions to rebuild its regulatory risk profile have been effective;" referred to as "credit supportive regulatory environment:

OGE Energy Corp.

Operating Characteristics:	
Operations:	*Oklahoma Gas and Electric* (OG&E) – regulated utility that generates, transmits, distributes and sells electric energy in Oklahoma and Arkansas. *Enogex LLC* – gathering, processing, transporting, and storing natural gas.
Total Assets:	$8,067 million
Percentage of Assets in Gas and Electric Operations:	**2009 % Assets** Electric Utility 67.9% Transportation & Storage 19.8% Gathering & Processing 10.7% Marketing 1.6%
State(s) of Utility Operations:	Oklahoma (90% of revenues) and western Arkansas
Number of Customers:	776,550 customers
Customers by Type:	**Customer Type** — **2009 % of Revenues** Residential 44.0% Commercial 27.0% Industrial 10.6% Oilfield 8.1% Public authorities 10.3%
Regulatory Environment:	
Test Year:	OK: Historic with adjustments for known and measurable changes. AK: Partial forecast.
Return on Equity (Latest Allowed):	10.75% (2005 OK) 10.25% (2009 AR)
Equity Ratio (Latest Allowed):	55.69% (2005 OK) 36.04% (2009 AR)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs, pension expense
Fuel/Gas Cost Recovery:	AR: fuel and purchased power costs are recovered through an annual energy cost recovery rider. OK: semi-automatic fuel adjustment clause adjusted annually subject to a cap on under- or over-recoveries.

(OGE cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Average 3 (OK and AR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"We view Oklahoma's and Arkansas' regulatory climates as credit supportive."

Portland General Electric Co.

Operating Characteristics:	
Operations:	*Electric Operations*-generation, purchase, transmission, distribution, and retail sale of electricity in Oregon.
Total Assets:	$5,172 million.
Percentage of Assets in Gas and Electric Operations:	Approximately 100% of assets in electric operations.
State(s) of Utility Operations:	Oregon
Number of Customers:	815,739 customers
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 47.9% Commercial 37.4% Industrial 10.1% Other 4.6%
Regulatory Environment:	
Test Year:	Partial or fully forecast
Return on Equity (Latest Allowed):	10.0% (2010 OR)
Equity Ratio (Latest Allowed):	50.00% (2010 OR)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension expense, deferred broker settlements , forced outage costs
Fuel/Gas Cost Recovery:	Are permitted to annually adjust rates to reflect forecasted power costs (PCAM). Also have a power cost adjustment mechanism that is subject to a deadband of $15 million below to $30 million above the ultimately established net variable power costs. Portland absorbs 100% of the costs/benefits within the deadband, and amounts above or below the deadband are shared 90% with customers and 10% with Portland. A refund would occur only to the extent that the refund would result in Portland's actual ROE for that year being no less than 100 basis points above the last authorized ROE. A surcharge would occur only to the extent that surcharge would result in Portland's actual ROE for that year being no greater than 100 basis points below the last authorized ROE.

(POR cont'd)

Sales and Weather Normalization:	Commercial and industrial customers of Portland are eligible for direct access.
RRA Regulatory Climate:	Average 3 (OR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	Decisions have been supportive of ratings stability

Progress Energy

Operating Characteristics:	
Operations:	*Carolina Power & Light* – generation, transmission, distribution, and sale of electricity in North Carolina and South Carolina. *Progress Energy Florida* – generation, transmission, distribution, and sale of electricity in Florida. *Other* – miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.
Total Assets:	$31,236 million
Percentage of Assets in Gas and Electric Operations:	Approximately 85% of assets in electric operations.
State(s) of Utility Operations:	Central and eastern North Carolina, northeastern South Carolina, and north and central Florida.
Number of Customers:	3.1 million customers (1.5 million in North and South Carolina, 1.6 million in Florida)
Customers by Type:	**Customer Type** / **2009 % of kWh** Residential 37.2% Commercial 26.0% Wholesale 18.1% Industrial 13.9% Other Retail 4.8%
Regulatory Environment:	
Test Year:	FL: Partial or full forecast NC, SC: Historic with adjustments for known and measurable changes
Return on Equity (Latest Allowed):	10.5% (2010 FL) 11.0% (2003 NC)
Equity Ratio (Latest Allowed):	46.74% (2010 FL) 51.14% (2003 NC)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs, costs associated with nuclear expansion in Florida, Energy Efficiency/DSM, pension expense

(PGN cont’d)

Fuel/Gas Cost Recovery:	FL: fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. SC: non-automatic electric fuel and purchased gas adjustment clauses are in place.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (NC) Average 1 (SC and FL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A/Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	"Operations under generally supportive regulatory environments"

SCANA Corp.

Operating Characteristics:	
Operations:	*Regulated Utilities*: SCE&G: engaged in the generation, transmission, distribution, and sale of electricity and the purchase, sale, and transportation of natural gas to customers in South Carolina. GENCO: sells electricity to SCE&G. Fuel Company: acquires, owns, and provides financing for SCE&G's nuclear fuel, fossil fuel, and emission allowances. PSNC Energy: purchases, sells, and transports natural gas to customers in North Carolina. CGT operates an interstate pipeline company in Georgia and South Carolina. *Unregulated* – markets natural gas, provides energy-related risk management services, and owns a fiber optic telecommunications network.
Total Assets:	$12,094 million
Percentage of Assets in Gas and Electric Operations:	Approximately 94% of assets in regulated utility operations.
State(s) of Utility Operations:	Central, southern, and southwestern South Carolina and North Carolina.
Number of Customers:	1.438 million customers (655,000 electric, 310,000 natural gas in South Carolina, 473,000 natural gas in North Carolina)
Customers by Type:	**Electric (SCE&G)** — **2009 % of Electric Revenues** Residential 43% Commercial 32% Industrial 16% Sales for Resale & Other 8% **Gas (SCE&G)** — **2009 % Gas % Transportation Revenues** Residential 46% Commercial 30% Industrial 19% Transportation Gas 4%

(SCG cont'd)

Regulatory Environment:	
Test Year:	NC, SC: Historic with adjustments for known and measurable changes
Return on Equity (Latest Allowed):	10.6% (2008 NC) 10.7% (2010 SC)
Equity Ratio (Latest Allowed):	54.00% (2008 NC) 52.96% (2010 SC)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension and OPEB costs, environmental remediation costs associated with manufactured gas plants
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. SC: non-automatic electric fuel and purchased gas adjustment clauses are in place. Allows for monthly adjustment to its gas costs that are calculated based on a rolling 12-month forecast of purchased gas costs.
Sales and Weather Normalization:	NC: rates decoupled , rates periodically adjusted based on average per customer consumption SC: Weather normalization adjustment in effect increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal.
RRA Regulatory Climate:	Above Average 2 (NC) Average 1 (SC)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa/Ba Financial Strength (40%): Baa
S&P's Regulatory Comment	"Supportive regulatory environments in South Carolina and North Carolina"

Sempra Energy

Operating Characteristics:	
Operations:	**Utility Operations***:* *San Diego Gas & Electric(SDG&E)*-electric and gas utility covering 4,100 square miles in the San Diego, CA area *Southern California Gas (SoCalGas)*-gas utility in central and southern California. **Non-Utility**: *Sempra Commodities*-commodities marketing and holds firm service capacity on the Rockies Express Pipeline. *Sempra Generation*-owns and operates natural gas-fired power plants and a wind-power generation project. *Sempra Pipelines & Storage*-operates and/or owns 2,000 miles of transmission pipelines and underground storage facilities. Also operates a small natural gas distribution utility serving Southwest Alabama. *Sempra LNG*-constructs and operates LNG receiving terminals.
Total Assets:	$28,512 million
Percentage of Assets in Gas and Electric Operations:	Approximately 63% of assets in electric and gas operations.
State(s) of Utility Operations:	Primarily central and southern California. Non-regulated operations or development projects by Sempra Generation, Sempra Pipelines & Storage and Sempra LNG in Alabama, Arizona, California, Indiana, Louisiana, Mississippi, Nevada, Texas and Hawaii.
Number of Customers:	Natural Gas Operations: 6.6 million Electric Operations: 1.4 million
Customers by Type:	**Electric** — **2009 % Revenues** Residential — 46% Commercial — 39% Industrial — 10% Direct Access — 5% **Gas** Residential — 69% Commercial & Industrial — 29% Electric Generation — 2% Wholesale — <1%

(SRE cont'd)

Regulatory Environment:	
Test Year:	AL: Historic with adjustments for known and measurable changes. CA: Forecast
Return on Equity (Latest Allowed):	**Electric:** 10.7% (2008 CA) **Gas:** 10.70% (2008 CA, SDG&E) 10.82% (2008 CA, SoCalGas) 13.60% (1995 AL)
Equity Ratio (Latest Allowed):	**Electric:** 49.00% (2008 CA) **Gas:** 49.00% (2008 CA, SDG&E) 48.00% (2008 CA, SoCalGas) 46.99% (1995 AL)
Earnings Sharing:	AL: regulator conducts quarterly reviews to determine if, based on projections, ROE will fall within range of 13.35% to 13.85%. Reductions in rates can be made quarterly to bring ROE within range. Increases allowed once a year. Equity on which ROE can be earned limited to 55%. If O&M expense exceed cap based on CPI, 75% of excess returned to customers. If below cap, company retains 50% of savings.
Deferral Mechanisms:	Environmental costs, pensions and OPEB; Additional incentive mechanisms in CA for operational activities e.g., safety, energy efficiency, and unbundled natural gas storage and system operator hub services.
Fuel/Gas Cost Recovery:	CA: Incentive for natural gas procurement (Gas Cost Incentive Mechanism) permits full recovery of costs incurred in range around the benchmark and sharing of costs/saving outside the range with core customers (primarily residential, small commercial and industrial customers)
Sales and Weather Normalization:	CA: decoupling mechanisms for both gas and electric utilities)
RRA Regulatory Climate:	Average 1 (CA) Above Average 2 (AL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): Baa
S&P's Regulatory Comment	"exceptionally supportive of credit quality"

Southern Co.

Operating Characteristics:	
Operations:	*Traditional Operating Companies:* Each own generation, transmission and distribution facilities: *Alabama Power* (Alabama) *Georgia Power* (Georgia) *Gulf Power* (Florida) *Mississippi Power* (Mississippi). *Regulated Generation :* *Southern Power*-constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates. Subject to FERC regulation Non-Utility Operations: Digital wireless communications, operates and provides services to utilities nuclear plants, acquires, owns, and constructs renewable generation assets.
Total Assets:	$52,046 million
Percentage of Assets in Gas and Electric Operations:	Approximately 94% of assets in traditional electric operating companies.
State(s) of Utility Operations:	Most of the states of Alabama and Georgia, along with the northwestern portion of Florida and southeastern Mississippi.
Number of Customers:	4.4 million customers (traditional operating companies)
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 36% Commercial 32% Industrial 19% Other - Retail 1% Wholesale 12%
Regulatory Environment:	
Test Year:	AL: Historic with adjustments for known and measurable FL: Partial or full forecast GA: Partial forecast MS: Full forecast

(SO cont'd)

Return on Equity (Latest Allowed):	14.00% (1980 AL) 12.00% (2002 FL) 11.15% (2010 GA) 12.88% (2001 MS)
Equity Ratio (Latest Allowed):	25.95% (1980 AL) 41.02% (2002 FL) 51.67% (2001 GA) 53.68% (2001 MS)
Earnings Sharing:	AL: Alabama Power operates under a Rate Stabilization and Equalization framework. Annual rate increases limited to 5% and rate increases for any two-year period, when averaged, cannot exceed 4% per year. If projected ROE is outside the allowed ROE range of 13%-14.5% rates are adjusted, subject to the limits above, to establish a 13.75% ROE. If actual earned ROE is above 14.5%, customers are refunded revenues that caused the earned ROE to exceed 14.5%. No provision for recovering shortfalls if the earned ROE is below 13%. GA: Georgia Power operating under an alternative rate plan since 1996; current version applies to years 2011-2013. Not permitted to file a general rate case unless earnings are projected to fall below a 10.25% ROE. Two-thirds of earnings above a 12.25% ROE are refunded to customers. No automatic recovery of any earnings shortfall below a 10.25% ROE, but may petition to utilize an Interim Cost Recovery Tariff to adjust earnings to a 10.25% ROE in lieu of filing a rate case. Permitted to retain 15% of the net present value of the net benefits generated by certain demand-side management programs.
Deferral Mechanisms:	Pension and employee benefit expense, Plant outage costs, Environmental remediation costs, Storm damage cost recovery, AL: Rate Certificated New Plant (CNP) mechanism adjusts rates annually to recognize the cost of placing new generating facilities in retail service and recovery of retail costs associated with certificated PPAs. CNP includes environmental costs and return on invested capital. GA: CWIP in rate base

(SO cont'd)

Fuel/Gas Cost Recovery:	AL: an Energy Cost Recovery (ECR) rate in place established on the basis of estimates of electric sales, fuel, and net purchased energy costs, and reflects accumulated over- or under-recovered amounts. GA: non-automatic fuel adjustment mechanism is in place. FL: the fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established base upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during with the PSC sets fuel factors for the next calendar year. MS: an automatic electric fuel adjustment clause is in effect, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (AL and MS) Average 1 (FL and GA)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A/Baa
S&P's Regulatory Comment	"Operations under generally constructive regulatory environments"

Vectren Corp

Operating Characteristics:	
Operations:	*Vectren Utility Holdings* – comprised of Indiana Gas, Southern Indiana Gas & Electric Company and Ohio operations. *Vectren Enterprises* – support services to utility operations.
Total Assets:	$3820 million
Percentage of Assets in Gas and Electric Operations:	Approximately 100% of assets in gas and electric operations of which 24% in generation.
State(s) of Utility Operations:	Nearly 2/3rds of the state of Indiana (gas and electric) and part of Ohio (gas).
Number of Customers:	679,000 gas and 141,000 electric customers in central and southern Indiana. 317,000 gas customers in west central Ohio.
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 58.2% Commercial 26.6% Industrial 15.2%
Regulatory Environment:	
Test Year:	Historic with adjustments for known and measurable changes for Indiana Partial forecast for Ohio
Return on Equity (Latest Allowed):	**Electric:** SIGECO: 10.4% (2007) Vectren Elec. Delivery Ohio: not specified (2009) previously 10.6% (2005) **Gas:** Indiana Gas: 10.20% (2008) SIGECO: 10.15% (2007)
Equity Ratio (Latest Allowed):	SIGECO: 47.05% (2007) Indiana Gas: 48.99% (2008 IN) Vectren Energy Delivery: 48.10% (2005 OH); 2009 not specified
Earnings Sharing:	n/a

(VVC cont'd)

Deferral Mechanisms:	Employee benefit deferral Demand side management expense Pipeline integrity expense Bad debt recovery mechanism (IN, OH) Environmental CWIP tracker Infrastructure cost recovery (IN, OH)
Fuel/Gas Cost Recovery:	Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC)
Sales and Weather Normalization:	SIGECO pursuing electric decoupling via sales reconciliation tracker in current rate case – decision expected 2011Q1 Decoupling (gas) in IN through weather normalization and conservation tariffs Straight fixed variable rate design (OH)
RRA Regulatory Climate:	Above Average 3 (IN) Average 1 (OH)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%):Baa/A
S&P's Regulatory Comment	"a supportive regulatory environment"

Wisconsin Energy Corp.

Operating Characteristics:	
Operations:	*Utility Energy* – electric and gas utilities operating together under the trade name of We Energies and Edison Sault serving customers in Wisconsin and Michigan. In October 2009 they reached an agreement to sell Edison Sault *Non-Utility Energy* –We Power designs, constructs, owns, and leases generating capacity.
Total Assets:	$12,698 million
Percentage of Assets in Gas and Electric Operations:	Approximately 85% are in gas and electric operations.
State(s) of Utility Operations:	Wisconsin and the Upper Peninsula of Michigan
Number of Customers:	1.1 million electric customers in Wisconsin & Michigan's Upper Peninsula 1.0 million gas customers in Wisconsin 0.5 million steam customers in Milwaukee
Customers by Type:	**Customer Type** — **2009% of Revenues** Residential — 40% Small Commercial/Industrial — 35% Large Commercial/Industrial — 25% Other — <1%
Regulatory Environment:	
Test Year:	MI: Partial forecast WI: Forecast
Return on Equity (Latest Allowed):	**Electric:** 10.40% (2009 WI) 10.25% (2010 MI) **Gas:** 10.40% (2009 WI)
Equity Ratio (Latest Allowed):	**Electric:** 53.02% (2009 WI) 47.61% (2010 MI) **Gas:** 53.02% (2009 WI)
Earnings Sharing:	n/a
Deferral Mechanisms:	Bad debt expense, recovery of unrecovered transmission costs

(WEC cont'd)

Fuel/Gas Cost Recovery:	Gas: Full recovery. Prior to 2010 incentive mechanism permitting increased revenues if gas purchased at prices lower than approved benchmarks, currently one-for-one recovery measured against a monthly benchmark with 2% tolerance. Costs above the benchmark subject to further review. (now in line with other Wisconsin utilities) Fuel and Purchased Power: no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis.
Sales and Weather Normalization:	TBD
RRA Regulatory Climate:	Above Average 2 (WI) Average 1 (MI)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	"More credit supportive" Wisconsin regulatory environment"

Xcel Energy Inc.

Operating Characteristics:	
Operations:	Regulated Utilities: *Northern States Power Minnesota*: electric distribution in Minnesota, North Dakota, and South Dakota. Gas distribution in Minnesota and North Dakota *Northern States Power Wisconsin*: electric and gas distribution in Wisconsin and Michigan *Public Service Co. of Colorado*: electric and gas distribution in Colorado *Southwestern Public Service*: electric distribution in Texas and New Mexico WestGas InterState-a small interstate natural gas pipeline. WYCO Development-50% ownership, develops and leases natural gas pipeline, storage, and compression facilities. Unregulated subsidiaries-rental housing projects
Total Assets:	$25,488 million
Percentage of Assets in Gas and Electric Operations:	Essentially 100% regulated operations (<1% revenues unregulated)
State(s) of Utility Operations:	Colorado, Michigan (western Upper Peninsula), Minnesota, New Mexico, North Dakota, South Dakota, Texas, northwestern Wisconsin and Texas
Number of Customers:	3.4 million electric customers and 1.9 million gas customers.
Customers by Type:	**Electric** — **2009 % of Revenues** Residential — 31% Commercial and Industrial — 53% Public Authorities & Other — 2% Wholesale — 12% Other — 4% **Gas Customer Type** Residential — 62% Commercial and Industrial — 34% Transportation & Other — 4%

(XEL cont’d)

Regulatory Environment:	
Test Year:	CO, NM, SD, TX: Historic with adjustments for known and measurable changes MN, MI: Partial forecast ND: Partial or full forecast WI: Full forecast
Return on Equity (Latest Allowed):	**Electric:** 10.50% (2009 CO) 10.88% (2009 MN) 10.75% (2008 ND) 10.18% (2008 NM) 12.00% (1990 SD) No ROE decision in last two rate cases. 10.40% (2009 WI) **Gas:** 10.25% (2007 CO) 10.09% (2010 MN) 10.75% (2007 ND) 10.75% (2008 WI)
Equity Ratio (Latest Allowed):	**Electric:** 58.56% (2009 CO) 52.47% (2009 MN) 51.77% (2008 ND) 51.23% (2008 NM) 42.50% (1990 SD) No Equity Ratio decision in last two rate cases. 52.30% (2009 WI) **Gas:** 60.17% (2007 CO) 52.46% (2010 MN) 51.59% (2007 ND) 52.51% (2008 WI)
Earnings Sharing:	ND: earnings in excess of 10.75% ROE are shared with customers. If earnings are between 10.75%-11.25% ROE, they are shared equally. Earnings above 11.25% ROE are shared 75% to ratepayers and 25% to shareholders. CO: customers receive bill credits if company did not achieve certain performance targets relating to electric reliability, customer service, and natural gas leak repair time.

(XEL cont'd)

Deferral Mechanisms:	CO, MN: Enhanced cost recovery for emissions reduction provides a return on CWIP and an incentive based ROE (energy savings goals) CO: specific retail rate rider for certain costs associated with renewable energy resources; Transmission Cost Adjustment recovers costs associated with investments in transmission facilities TX: recovery of certain transmission investments and other transmission costs through TCRF rider
Fuel/Gas Cost Recovery:	Cost-of-Energy Adjustment mechanisms for purchases of coal, nuclear fuel and natural gas in all states except Wisconsin which does not permit recovery of purchased electric energy or electric fuel
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (WI) Average 1 (MI and ND) Average 2 (CO, MN, and SD) Below Average 1 (NM and TX)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%):Baa
S&P's Regulatory Comment	"credit supportive regulation"

[i] Lost and Unaccounted for Trackers (LUAF) are in 47 of 50 states (excluding Michigan, Montana and South Dakota as of June 2010 (AGA, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List as of June 2010)*

[ii] RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

[iii] Financial strength is comprised 10% liquidity and four metrics each weighted 7.5% for a total of 40%. The four metrics measured are: 1) (Cash from operations (CFO) pre-working capital (WC) plus interest) over interest expense; 2) CFO Pre-WC/Debt; 3) (CFO Pre-WC less dividends)/Debt; and 4) Debt/Book Capitalization.

APPENDIX C

DISCOUNTED CASH FLOW TEST

1. CONCEPTUAL UNDERPINNINGS

The discounted cash flow (DCF) 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, which is the rate that equates the price of the stock to the discounted value of future cash flows.

2. DCF MODELS

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. To estimate the DCF cost of equity, both constant growth and a three-stage growth models were utilized. These two models are discussed below.

a. Constant Growth Model

The constant growth 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. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth 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[24]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

[24] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

Using the three-stage 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)

3. GROWTH COMPONENT OF THE DCF MODELS

The growth component of the DCF models is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.) Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be.

a. Constant Growth Model Growth Rates

In the application of the constant growth model, two estimates of investors' expectations of long-term earnings growth were relied upon: a consensus of investment analysts' earnings forecasts and an estimate of the sustainable growth rate. The earnings growth rate forecasts were obtained from four different sources, I/B/E/S (First Call), Reuters, *Value Line*, and Zacks. I/B/E/S (First Call) is a leading provider of earnings expectations data. I/B/E/S compiles data from forecasts made by investment analysts for thousands of publicly traded companies.[25] The I/B/E/S consensus earnings growth rate forecasts for each company are intended to represent the expected annual increase in operating earnings over the next business cycle. Reuters[26] is a global provider 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 US 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 growth from external financing.

[25] I/B/E/S collects data from over 4,000 analysts at over 800 institutions worldwide covering over 12,000 companies in more than 45 countries.
[26] Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries.

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 BR and SV. 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.

b. Expected Long-Term Growth in the Economy (Stage 3 Growth)

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 GDP 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.

c. Reliability of Analysts' Earnings Forecasts

The reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. .

The potential bias of the analysts' growth rates for the U.S. utilities was assessed in three separate ways. First, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the I/B/E/S forecasts were compared to the consensus forecasts of long-term growth. For the sample of U.S. electric utilities, the average expected long-term growth rate, as estimated using the I/B/E/S consensus earnings growth forecasts, for the entire 1995-2010 period of analysis used in the DCF-based risk premium test was 5.3%. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March and October editions, 1995-2010), was 5.1% from 1995-2010. The similar expected nominal growth in the economy compared to the I/B/E/S forecasts for the utility sample suggests that the I/B/E/S forecasts are not an upwardly biased measure of investor expectations.

Second, the I/B/E/S forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* as no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Over the entire period of analysis of the DCF-based risk premium test (1995-2010), the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 5.5%, compared to the average I/B/E/S long-term earnings growth rate forecast for the same companies of 5.3%. Again, the higher *Value Line* than I/B/E/S forecasts suggest that the I/B/E/S forecasts are not upwardly biased.

Third, allowed returns for U.S. utilities are derived in large part by reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favour the use of forecast growth, while another may favour the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to the estimated constant growth DCF costs of equity for the benchmark sample of U.S. utilities estimated using the I/B/E/S analysts' growth forecasts over the same period (1995-2010), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the various DCF models as follows:

Table C-1

Average Allowed ROEs (1995-2010)	**10.9%**	**Average Difference From Allowed ROEs**
Constant Growth DCF Cost of Equity (1995-2010)	10.3%	-0.6%

Sources: Schedule 13, page 1 of 4 and Schedule 14, page 1 of 2.

The comparison of the DCF costs of equity to the ROEs allowed by regulators provides a further indication that the earnings forecasts are not an upwardly biased measure of investor expectations.

4. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

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 December 2010 as D_o; and,

(2) the average of the daily close prices for the period October 1, 2010 to December 31, 2010 as P_o.

The constant growth model was applied using two estimates of long-term growth, the average of four investment analysts' long-term earnings growth forecasts compiled by I/B/E/S (First Call), Reuters, *Value Line*, and Zacks, and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the average of the four earnings growth forecasts as of December 2010 were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The sustainable growth rate was derived from the fourth quarter 2010 *Value Line* forecasts as described on page C-5 above.

b. Three-Stage Model

The three-stage DCF model applied to the sample of U.S. electric utilities relied on the average of the four sources of analysts' earnings forecasts for the first five years (Stage 1), the average of the Stage 1 forecast and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). In the three-stage DCF test, the long-run expected nominal rate of growth in GDP of 4.9% was based on the consensus of economists' forecasts for the period 2013-2020 found in Blue Chip *Financial Forecasts*, December 1, 2010.[27]

A three-stage model was also used in the application of the DCF-based equity risk premium test. In the application of this test, estimates of the DCF cost of equity for the sample as a whole were made for each month from January 1995 to December 2010. For each month, the dividend yield to which the growth rates were applied was the sample average dividend yield in that month.

For each month in the analysis, the sample average I/B/E/S forecast growth rate in that month was applied for the first stage of the model (Years 1 to 5). For the third stage (Years 11 and beyond), the expected growth rate was represented by the most recent long-term nominal GDP growth rate forecast available in that month from Blue Chip *Financial Forecasts*. As noted above, Blue Chip *Financial Forecasts* publishes long-term GDP growth forecasts in June and December of each year.[28] Therefore, as examples, the Stage 3 expected growth rate for the months June through November 2009 was represented by the nominal GDP growth forecast published in June 2009. The Stage 3 expected growth rate for the months December 2009 through May 2010 was represented by the December 2009 long-term nominal GDP forecast. Similar to the three-stage DCF test, Stage 2 growth (Years 6 to 10) is equal to the average of Stage 1 and Stage 3 growth rates.

[27] Published twice annually in June and December.
[28] Prior to December 1996, the long-term GDP forecasts were published in the March and October editions of Blue Chip *Financial Forecasts*.

APPENDIX D

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity.

This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[29]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

[29] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[30]

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000 and took out a mortgage for the full amount. My home is currently worth $250,000 and my mortgage is now $85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $165,000 (market value of $250,000 less the $85,000 unpaid mortgage), not

[30] The minimum financing flexibility allowance can be estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x "bare-bones" Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a retention rate of 25% and a "bare-bones" cost of equity of 9.75%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \text{ x } 9.75\%}{1+[.25(1.075-1.0)]}$$

$$\text{ROE} = 10.3\%$$

The difference of approximately 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

the "book value" of the equity in my home of $15,000, which reflects the original purchase price less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

The rationale for the differences in the required return on equity for companies of similar business risk but different financial risk begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. In the absence of both the deductibility of interest expense for corporate income tax purposes and costs associated with excessive debt (e.g., bankruptcy), the overall cost of capital to a firm would not change when a firm changes its capital structure.[31]

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. However, in a competitive environment, the sum of the available cash flows does not change when debt is added to the capital structure. The available cash flows are now split between debt and equity holders. Since there are fixed debt costs that must be paid before the equity shareholder receives any return, the variability of the equity return increases as debt rises. The higher the debt ratio, the higher the potential volatility of the equity return and the greater the risk that equity shareholders will not recover their invested capital and a compensatory return thereon. Hence, as the debt ratio rises, the cost of equity rises. The higher cost rates of both the debt and equity offset the higher proportion of debt in the capital structure, so that the overall cost of capital does not change.

The deductibility of interest expense for corporate income tax purposes alters 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

[31] The seminal theory, which was premised on no risk to excessive debt, was set out in Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48: 261-297 (June 1958).

assumption of debt. In the absence of offsetting factors, when interest expense is deductible for corporate income tax purposes, the after-tax cost of capital declines as more debt is used.[32]

Offsetting some of the advantage of debt at the corporate level are the higher personal tax rates on interest income than on dividend income and capital gains. When personal income tax rates on dividends and capital gains are lower than the personal income tax rate on interest income, all other things equal, taxable investors would prefer firms to use equity rather than debt. If taxes were the only consideration, there are combinations of corporate and personal income taxes at which the corporate tax advantages of using debt are completely offset by the personal tax advantages to holding equity rather than debt.[33]

However, factors other than taxes impact the choice of capital structure. The addition of debt to the capital structure is not risk-free. There is a loss of financial flexibility and an increasing potential for bankruptcy as the debt ratio rises. The result is an increase in the cost of capital as leverage is increased. For example, as the percentage of debt in the capital structure increases, the company's credit rating may decline and its cost of debt will increase. When the loss of financing flexibility and costs of financial distress impair a firm's ability to operate efficiently, e.g., to pursue opportunities to grow the business or even to obtain trade credit as required, the cost of equity and the overall cost of capital will likely increase more than pure theory would indicate.

It is impossible to state with precision whether, within a specific range of capital structures, raising the debt ratio will leave the overall cost of capital unchanged or result in some decline. However, what is indisputable is that the cost of equity does change when the debt ratio changes, increasing when the debt ratio increases and, conversely, decreasing when the debt ratio falls.

[32] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).
[33] The offsetting impacts of lower personal tax rates on equity income compared to interest income were examined in Merton H. Miller, "Debt and Taxes," *The Journal of Finance*, 32: 261-276 (May 1977). At the 2012 marginal corporate and personal income tax rates (on interest, dividends and capital gains) in Canada, the gain from corporate leverage is relatively small.

The cost of equity has been estimated using samples of comparable proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the book value capital structure. Regulatory convention applies the allowed ROE to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Three approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity when interest expense is deductible for income tax purposes.

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 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.

Table D-1 below shows the adjustments to the cost of equity that are required to recognize the difference in financial risk between the market value capital structures of the Canadian and U.S. utility samples and the book value capital structures under the three approaches. Schedule 22 provides the formulas for estimating the change in the cost of equity due to capital structure differences under each of the three approaches. Approach 3 and Approach 1 are identical when the corporate income tax rate is zero.

Table D-1

	Cost of Equity	Market Value Equity Ratio	Book Value Equity Ratio	Adjustment to ROE for Book Value Capital Structure		
				Approach 1 (28% tax rate)	Approach 2 (28% tax rate)	Approach 3 (0% tax rate)
Canadian Utilities	9.3%	55%	40%	2.1%	1.3%	1.6%
U.S. Utilities	9.6%	56%	45%	1.4%	0.9%	1.1%

Source: Schedules 4, 5, 21 and 22.

Notes: Based on incremental utility cost of long-term debt at the time the DCF costs were estimated of 5.0% for the A-rated Canadian utility sample and 5.15% for the BBB rated U.S. utilities sample. Corporate income tax rate of 28% is estimated combined federal/provincial rate for Canada.

Full recognition of the difference in financial risk between the market value equity ratios of the two utility samples results in an increase in the range of approximately 0.9% to 2.1% (mid-point of approximately 140 basis points based on all estimates in Table D-1).

APPENDIX E

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.

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

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007

ATCO Utilities
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

Edmonton Water/EPCOR Water Services
1994, 2000, 2006, 2008

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

FortisBC
1995, 1999, 2001, 2004

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

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

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

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

Terasen Gas
1992, 1994, 2005, 2009

Terasen Gas (Whistler)
2008

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
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
Nova Scotia Power	Calculation of ROE	2009
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

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Government Securities													
	T-Bills		10 Year		Long-Term		Canada Bonds Over 10	Canadian Inflation	Canadian A-Rated	Canadian A-Rated Spread	Moody's U.S. Utility Long-Term	Moody's U.S. Utility Long-Term	Exchange Rates (Canadian dollars	
Year	Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]	Years [3/]	Indexed Bonds	Utility Bonds [4/]	Over Long Canadas	A-Rated Bonds	Baa-Rated Bonds	in U.S. funds)	
Annual														
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44	9.86	10.06	0.86	
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28	9.36	9.55	0.84	
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01	1.33	8.69	8.86	0.82	
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	1.22	7.59	7.91	0.77	
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	1.12	8.30	8.63	0.73	
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	0.88	7.89	8.29	0.73	
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	0.63	7.75	8.16	0.73	
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	0.53	7.60	7.96	0.72	
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	0.79	7.04	7.27	0.68	
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	1.20	7.62	7.88	0.67	
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.05	1.34	8.24	8.36	0.67	
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.10	1.33	7.74	8.00	0.65	
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.08	1.41	7.34	7.99	0.64	
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.65	1.33	6.54	6.80	0.72	
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.14	1.03	6.14	6.39	0.77	
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.43	1.05	5.62	5.90	0.83	
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.36	1.09	6.06	6.31	0.89	
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.52	1.22	6.06	6.33	0.94	
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.29	2.26	6.54	7.31	0.94	
2009	0.31	0.15	3.27	3.29	3.85	4.10	3.85	1.86	6.10	2.24	5.99	6.95	0.88	
2010	0.59	0.14	3.17	3.14	3.70	4.17	3.63	1.36	5.20	1.51	5.38	5.89	0.97	

[1/] Rates on new issues.

[2/] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006, when no 30-year Treasury bonds were issued. The theoretical 30-year Treasury bond yield represents the yield on all outstanding Treasury bonds with a term to maturity greater than 25 years plus an extrapolation factor published by the U.S. Department of the Treasury to allow the estimation of a 30-year rate; 30-year maturities February 2006 forward.

[3/] Terms to maturity of l0 years or more.

[4/] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		Government Securities												
		T-BILLS		10 Year		Long-Term		Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [4/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Moody's U.S. Utility Long-Term Baa-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Year		Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]							
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	6.02	0.93	6.06	6.26	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.34	1.04	6.45	6.69	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.23	1.10	6.11	6.42	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	5.98	1.06	5.95	6.18	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.78	1.06	5.72	5.92	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.47	1.09	5.43	5.75	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.20	0.99	5.49	5.79	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.25	1.06	5.82	6.14	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.32	1.09	5.92	6.20	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.65	1.10	6.41	6.63	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.34	1.12	6.09	6.34	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.13	1.06	5.82	6.07	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	1.06	5.92	6.16	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.49	1.14	6.08	6.32	0.92
	q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.75	1.30	6.19	6.45	0.97
	q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.61	1.39	6.05	6.38	1.02
2008	q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.65	1.58	6.16	6.59	0.99
	q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.84	1.74	6.30	6.85	0.99
	q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.21	2.10	6.58	7.22	0.95
	q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.47	3.60	7.13	8.59	0.82
2009	q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.06	3.38	6.44	7.95	0.80
	q2	0.21	0.16	3.28	3.39	3.90	4.24	3.86	1.97	6.27	2.37	6.35	7.48	0.87
	q3	0.22	0.16	3.38	3.41	3.89	4.17	3.94	1.76	5.49	1.60	5.54	6.21	0.92
	q4	0.21	0.06	3.42	3.49	3.95	4.35	3.96	1.57	5.56	1.62	5.65	6.16	0.94
2010	q1	0.20	0.12	3.43	3.69	4.01	4.59	3.94	1.54	5.45	1.44	5.80	6.17	0.96
	q2	0.46	0.17	3.36	3.32	3.80	4.22	3.73	1.45	5.37	1.57	5.46	6.05	0.96
	q3	0.74	0.15	2.88	2.65	3.49	3.73	3.42	1.35	5.00	1.51	4.96	5.54	0.96
	q4	0.97	0.14	2.99	2.91	3.48	4.15	3.42	1.11	4.98	1.50	5.31	5.79	0.99
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.27	1.05	6.01	6.22	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.15	1.06	5.78	6.01	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.28	1.08	5.97	6.25	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.32	1.13	5.90	6.16	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.50	1.12	6.10	6.35	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.66	1.17	6.24	6.46	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07	5.72	1.27	6.18	6.46	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14	5.74	1.28	6.17	6.45	0.95
	Sep	3.96	3.82	4.34	4.59	4.44	4.83	4.44	2.07	5.79	1.35	6.22	6.45	1.01
	Oct	3.96	3.94	4.31	4.48	4.38	4.74	4.39	2.05	5.67	1.29	6.07	6.36	1.06
	Nov	3.91	3.15	3.98	3.97	4.16	4.40	4.15	2.07	5.67	1.51	6.00	6.34	1.00
	Dec	3.82	3.36	3.99	4.04	4.10	4.45	4.10	1.91	5.47	1.37	6.07	6.43	1.01
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.67	1.49	6.07	6.40	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.66	1.57	6.22	6.63	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.63	1.69	6.20	6.74	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.78	1.70	6.22	6.74	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.83	1.70	6.36	6.93	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	5.89	1.81	6.32	6.87	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	5.92	1.82	6.44	7.03	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.09	2.08	6.32	6.94	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.64	2.41	6.98	7.69	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.61	3.33	8.01	9.28	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.48	3.58	7.18	8.72	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.33	3.88	6.20	7.76	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.33	3.56	6.52	7.97	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.07	3.37	6.38	7.85	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	6.78	3.21	6.41	8.04	0.79
	Apr	0.20	0.14	3.09	3.16	3.84	4.05	3.74	2.05	6.71	2.87	6.55	7.91	0.84
	May	0.20	0.14	3.39	3.47	3.99	4.34	3.93	2.00	6.14	2.15	6.53	7.56	0.91
	Jun	0.24	0.19	3.36	3.53	3.86	4.32	3.91	1.86	5.94	2.08	5.96	6.96	0.86
	Jul	0.24	0.18	3.46	3.52	3.95	4.31	4.01	1.73	5.54	1.59	5.68	6.45	0.93
	Aug	0.20	0.15	3.37	3.40	3.89	4.18	3.94	1.81	5.45	1.56	5.54	6.17	0.91
	Sep	0.22	0.14	3.31	3.31	3.84	4.03	3.87	1.74	5.49	1.65	5.41	6.00	0.93
	Oct	0.22	0.05	3.42	3.41	3.92	4.23	3.95	1.60	5.49	1.57	5.55	6.12	0.93
	Nov	0.21	0.06	3.22	3.21	3.84	4.20	3.83	1.58	5.50	1.66	5.54	6.04	0.95
	Dec	0.19	0.06	3.61	3.85	4.08	4.63	4.09	1.53	5.69	1.61	5.86	6.31	0.96
2010	Jan	0.16	0.08	3.34	3.63	3.94	4.51	3.90	1.49	5.42	1.48	5.73	6.09	0.94
	Feb	0.16	0.13	3.39	3.61	4.02	4.55	3.94	1.58	5.49	1.47	5.77	6.17	0.95
	Mar	0.28	0.16	3.56	3.84	4.07	4.72	3.99	1.56	5.44	1.37	5.89	6.25	0.98
	Apr	0.39	0.16	3.65	3.69	4.01	4.53	3.94	1.49	5.40	1.39	5.60	5.98	0.99
	May	0.50	0.16	3.36	3.31	3.73	4.22	3.65	1.45	5.46	1.73	5.57	6.16	0.96
	Jun	0.50	0.18	3.08	2.97	3.65	3.91	3.59	1.42	5.24	1.59	5.21	6.00	0.94
	Jul	0.66	0.15	3.11	2.94	3.69	3.98	3.62	1.51	5.17	1.48	5.17	5.80	0.97
	Aug	0.70	0.14	2.78	2.47	3.44	3.52	3.36	1.34	5.01	1.57	4.78	5.36	0.94
	Sep	0.87	0.16	2.75	2.53	3.35	3.69	3.27	1.20	4.82	1.47	4.93	5.45	0.97
	Oct	0.92	0.12	2.80	2.63	3.44	3.99	3.32	1.09	4.89	1.45	5.21	5.70	0.98
	Nov	1.01	0.17	3.07	2.81	3.48	4.12	3.45	1.12	5.04	1.56	5.28	5.75	0.97
	Dec	0.97	0.12	3.11	3.30	3.52	4.34	3.48	1.11	5.00	1.48	5.45	5.93	1.01
2011	Jan	0.96	0.15	3.27	3.42	3.73	4.58	3.68	1.38	5.18	1.45	5.61	6.05	1.00
	Feb	0.96	0.15	3.30	3.42	3.70	4.49	3.65	1.22	5.14	1.44	5.51	5.92	1.03

[1/] Rates on new issues.
[2/] Theoretical 30-year yield, 2004 to January 2006. 30-year maturities February 2006 forward.
[3/] Terms to maturity of l0 years or more.
[4/] Series of liquid long-term utility bonds maintained by Foster Associates.
Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
RBC Capital Markets, www.ustreas.gov

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	11/09	AUC	2009-216	64.00	0.00	36.00	9.00	n/a
ATCO Electric								
Transmission	11/09	AUC	2009-216	58.00	6.00	36.00	9.00	n/a
Distribution	11/09	AUC	2009-216	54.10	6.90	39.00	9.00	n/a
ENMAX								
Transmission	11/09	AUC	2009-216	63.00	0.00	37.00	9.00	n/a
Distribution	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a
EPCOR								
Transmission	11/09	AUC	2009-216	63.00	0.00	37.00	9.00	n/a
Distribution	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a
FortisAlberta Inc.	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	n/a
Hydro One Transmission	8/07; 12/10	OEB	EB-2006-0501; EB-2010-0002	60.00	0.00	40.00	9.66	3.94
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a
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	3/06;11/08	NSUARB	2006 NSUARB 23; 2008 NSUARB 140	53.30	9.20	37.50	9.35	n/a
Ontario Electricity Distributors	12/09; 11/10	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.66	3.94
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.43 (2011) 9.55 (2012)	3.61 (2011) 3.85 (2012) [1]
Gas Distributors								
AltaGas Utilities	11/09	AUC	2009-216	57.00	0.00	43.00	9.00	n/a
ATCO Gas	11/09	AUC	2009-216	54.10	6.90	39.00	9.00	n/a
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
Gaz Métro	12/09, 11/10	Régie	D-2009-156 (formula), 2010-149 (ROE)	54.00	7.50	38.50	9.09	4.15
Pacific Northern Gas-West	5/10	BCUC	G-84-10	51.15	3.85	45.00	10.15	n/a
Terasen Gas	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	n/a
Terasen Gas (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	n/a
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								
ATCO Pipelines	11/09; 5/10	AUC	2009-216; 2010-228	49.30	5.70	45.00	9.00	n/a
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; 12/09	NEB	RH-2-94;TG-06-2007; NEB Letter 12-09	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] The forecast long Canada yield of 3.85% (2012) was estimated.

[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																					
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
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
Terasen Gas [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
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**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**8.96**	**8.59**	**8.77**	**8.71**	**9.13**
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**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.02**	**8.66**	**8.78**	**8.77**	**9.11**

[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

Source: Regulatory Decisions

**COMPARISON BETWEEN ALLOWED RETURNS
FOR CANADIAN AND U.S. UTILITIES**

	Canadian Utilities			U.S. Utilities			U.S. Gas Utilities			U.S. Electric Utilities		
Year	Allowed ROE	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.62	4.07	12.67	8.62	4.05	12.70	8.62	4.08
1991	13.56	9.72	3.85	12.51	8.09	4.43	12.46	8.09	4.38	12.55	8.09	4.47
1992	12.94	8.68	4.26	12.06	7.68	4.39	12.01	7.68	4.34	12.09	7.68	4.42
1993	12.16	7.86	4.30	11.37	6.58	4.79	11.35	6.58	4.77	11.41	6.58	4.83
1994	11.50	8.69	2.81	11.34	7.41	3.93	11.35	7.41	3.94	11.34	7.41	3.93
1995	12.13	8.41	3.72	11.51	6.81	4.70	11.43	6.81	4.62	11.55	6.81	4.74
1996	11.36	7.75	3.62	11.29	6.72	4.57	11.19	6.72	4.47	11.39	6.72	4.67
1997	10.84	6.66	4.18	11.34	6.57	4.77	11.29	6.57	4.72	11.40	6.57	4.83
1998	10.15	5.59	4.56	11.59	5.53	6.06	11.51	5.53	5.98	11.66	5.53	6.13
1999	9.50	5.72	3.78	10.74	5.91	4.83	10.66	5.91	4.75	10.77	5.91	4.86
2000	9.79	5.71	4.08	11.41	5.88	5.53	11.39	5.88	5.51	11.43	5.88	5.55
2001	9.68	5.77	3.92	11.05	5.47	5.58	10.95	5.47	5.48	11.09	5.47	5.62
2002	9.62	5.67	3.95	11.10	5.41	5.69	11.03	5.41	5.62	11.16	5.41	5.75
2003	9.71	5.31	4.40	10.98	5.03	5.95	10.99	5.03	5.96	10.97	5.03	5.94
2004	9.59	5.11	4.48	10.66	5.09	5.56	10.59	5.09	5.50	10.73	5.09	5.64
2005	9.51	4.38	5.13	10.50	4.52	5.98	10.46	4.52	5.94	10.54	4.52	6.02
2006	9.02	4.26	4.76	10.39	4.87	5.52	10.44	4.87	5.57	10.36	4.87	5.49
2007	8.66	4.30	4.37	10.30	4.80	5.51	10.24	4.80	5.44	10.36	4.80	5.56
2008	8.78	4.04	4.74	10.42	4.22	6.20	10.37	4.22	6.15	10.46	4.22	6.24
2009	8.77	3.85	4.92	10.36	4.10	6.27	10.19	4.10	6.10	10.48	4.10	6.39
2010	9.11	3.70	5.42	10.24	4.17	6.07	10.08	4.17	5.91	10.34	4.17	6.17
Means:												
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**7.74**	**4.38**	**12.19**	**7.74**	**4.45**
1994-1997	**11.46**	**7.88**	**3.58**	**11.37**	**6.88**	**4.49**	**11.32**	**6.88**	**4.44**	**11.42**	**6.88**	**4.54**
1998-2010	**9.38**	**4.88**	**4.50**	**10.75**	**5.00**	**5.75**	**10.68**	**5.00**	**5.68**	**10.80**	**5.00**	**5.80**
1996-2010	**9.61**	**5.19**	**4.42**	**10.82**	**5.22**	**5.61**	**10.76**	**5.22**	**5.54**	**10.88**	**5.22**	**5.66**

Sources: www.bankofcanada.ca; Canadian Regulatory decisions; www.federalreserve.gov; Regulatory Research Associates at www.snl.com; www.ustreas.gov.

Schedule 3

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
Chatham-Kent Energy Inc.					A		Excellent
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured)	Excellent
Enersource	A						
ENMAX Corp.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
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) (Senior Unsecured)		Baa1 (Senior Unsecured)			
Hamilton Utilities					A	A (Senior Unsecured)	Excellent
Hydro One Inc.		A(high) (Senior Unsecured)		Aa3 (Senior Unsecured) [1/]	A+ [1/]	A+ (Senior Unsecured) [1/]	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 (Senior Secured)	Baa1 [2/]	A2 (First Mortgage) [2/]			
Nova Scotia Power		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	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
Gaz Métro L.P.		A (Senior Secured)			A-	A (Senior Secured)	Excellent
Pacific Northern Gas		BBB(low) (Senior Secured)					
Terasen Gas [3/]		A (Senior Unsecured)		A3 (Senior Unsecured)	A	A (Senior Unsecured)	Excellent
				A1 (Senior Secured)		AA- (Senior Secured)	
Terasen Gas (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)			
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)	Strong
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Satisfactory
TransCanada PipeLines Ltd.		A (Senior Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Strong
Westcoast Energy Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Medians							
Electric Utilities		**A**		**A3**	**A**	**A-**	**Excellent**
Gas Distributors		**A**		**A3**	**A-**	**A**	**Excellent**
Pipelines		**A**		**A3**	**A-**	**A-**	**Strong**
All Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Investor Owned Companies		**A**		**A3**	**A-**	**A-**	**Excellent/Strong**

[1/] Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.
[2/] Ratings withdrawn at request on company March 2010; previously rated Baa1.
[3/] S&P ratings affirmed then withdrawn September 23, 2010.

Source: www.dbrs.com, www.moodys.com, Standard & Poor's.

Schedule 4

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2009)[1/]

Company	Total Debt [2/]	Preferred Stock [3/]	Common Stock Equity [4/]
Electric Utilities			
AltaLink L.P.	54.1%	0.0%	45.9%
CU Inc.	53.7%	7.7%	38.6%
Enersource	55.7%	0.0%	44.3%
ENMAX Corp.	43.4%	0.0%	56.6%
EPCOR Utilities Inc.	43.7%	0.0%	56.3%
FortisAlberta Inc.	57.3%	0.0%	42.7%
FortisBC Inc.	59.2%	0.0%	40.8%
Hamilton Utilities	31.8%	0.0%	68.2%
Hydro One Inc.	56.2%	2.6%	41.2%
Hydro Ottawa Holding Inc.	43.2%	0.0%	56.8%
London Hydro	40.8%	0.0%	59.2%
Maritime Electric	58.5%	0.0%	41.5%
Newfoundland Power	55.1%	1.0%	43.8%
Nova Scotia Power	58.2%	4.6%	37.2%
Toronto Hydro	54.8%	0.0%	45.2%
Veridian Corp.	38.5%	0.0%	61.5%
Gas Distributors [1/]			
Enbridge Gas Distribution	56.2%	2.2%	41.6%
Gaz Métro L.P.	63.9%	0.0%	36.1%
Pacific Northern Gas	47.8%	2.8%	49.4%
Terasen Gas	60.9%	0.0%	39.1%
Union Gas Limited	59.3%	2.6%	38.1%
Pipelines			
Enbridge Pipelines Inc.	57.1%	0.0%	42.9%
Nova Gas Transmission Ltd.	64.3%	0.0%	35.7%
Trans Québec & Maritimes Pipeline	62.9%	0.0%	37.1%
TransCanada PipeLines Ltd.	56.5%	1.1%	42.4%
Westcoast Energy Inc.	58.7%	5.4%	35.9%
Medians			
Electric Utilities	**54.5%**	**0.0%**	**44.7%**
Gas Distributors	**59.3%**	**2.2%**	**39.1%**
Pipelines	**58.7%**	**0.0%**	**37.1%**
All Companies	**56.2%**	**0.0%**	**42.6%**
All Investor Owned Companies	**58.2%**	**0.0%**	**40.8%**

[1/] The average of the four quarters ending September 2010 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.
[2/] Includes preferred securities classified as debt.
[3/] Includes non-controlling interests in preferred shares of subsidiary companies and preferred securities.
[4/] Includes non-controlling interests in common shares of subsidiary companies.

Note: Financial statements for Terasen Gas (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

Schedule 5

CAPITAL STRUCTURE RATIOS
OF U.S. ELECTRIC UTILITIES
(Four Quarters Ending September 2010)

Company	Total Debt [1/]	Preferred Stock [2/]	Common Stock Equity [3/]
ALLETE, Inc.	43.1	0.0	56.9
Alliant Energy Corporation	47.1	4.2	48.7
Dominion Resources, Inc.	58.9	0.9	40.3
Duke Energy Corporation	44.3	0.0	55.7
IDACORP, Inc.	50.9	0.0	49.1
NextEra Energy, Inc.	59.7	0.0	40.3
OGE Energy Corp.	54.6	0.0	45.4
Portland General Electric Company	53.5	0.0	46.5
Progress Energy	56.2	0.4	43.4
SCANA Corporation	58.1	0.0	41.9
Sempra Energy	48.3	1.0	50.7
Southern Company	55.3	3.0	41.7
Vectren Corporation	56.1	0.0	43.9
Wisconsin Energy Corporation	57.3	0.4	42.3
Xcel Energy, Inc.	54.6	0.6	44.8
Mean	**53.2**	**0.7**	**46.1**
Median	**54.6**	**0.0**	**44.8**

1/ Includes preferred securities classified as debt.
2/ Includes non-controlling interests in preferred shares of subsidiary companies and preferred securities.
3/ Includes non-controlling interests in common shares of subsidiary companies.

Source: Reports to Shareholders.

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

	EBIT Coverage (X)				FFO Interest Coverage (X)				FFO To Debt (%)			
Company	**2009**	**2008**	**2007**	**3 Year Average**	**2009**	**2008**	**2007**	**3 Year Average**	**2009**	**2008**	**2007**	**3 Year Average**
Electric Utilities												
AltaLink L.P.	1.8	1.8	1.7	1.8	3.0	3.2	3.0	3.1	12.7	12.7	11.6	12.3
Chatham-Kent Energy Inc.	3.7	3.5	3.7	3.6	5.4	5.5	5.2	5.4	29.5	34.9	32.9	32.4
CU Inc.	2.5	2.2	2.1	2.3	3.4	3.6	3.5	3.5	17.7	17.6	17.4	17.6
Enersource				2.3 [1]				3.3 [1]				16.1 [1]
ENMAX Corp.	2.8	2.7	2.6	2.7	3.3	3.8	3.8	3.6	13.6	13.7	17.1	14.8
EPCOR Utilities Inc.	2.1	1.5	2.6	2.1	2.6	2.9	3.3	2.9	16.4	15.1	20.8	17.4
FortisAlberta Inc.	2.1	2.0	2.0	2.0	3.8	4.0	3.9	3.9	13.2	13.4	13.6	13.4
FortisBC Inc.	2.0	2.1	2.0	2.0 [2]	2.9	2.7	2.8	2.8 [5]	11.9	11.2	10.9	11.3 [5]
Hamilton Utilities	3.3	3.3	3.7	3.4	4.6	5.1	5.0	4.9	29.6	35.3	34.5	33.1
Hydro One Inc.	2.1	2.8	3.0	2.6	2.8	4.0	3.7	3.5	11.4	14.5	13.9	13.3
Hydro Ottawa Holding Inc.	4.3	4.1	3.8	4.1	6.2	6.2	5.6	6.0	27.3	25.5	21.6	24.8
London Hydro	3.3	2.9	3.4	3.2 [3]		4.8	4.4	4.6	27.5	26.2	23.7	25.8 [3]
Maritime Electric	2.0	2.0	2.1	2.0	2.7	2.8	2.8	2.8	13.3	14.1	13.3	13.6
Newfoundland Power	2.4	2.5	2.2	2.4 [2]	3.1	3.0	2.7	2.9 [5]	15.0	15.8	12.6	14.5 [5]
Nova Scotia Power	2.2	2.4	2.6	2.4	3.1	3.1	3.3	3.2	14.5	15.9	16.9	15.8
Toronto Hydro	1.6	1.8	2.2	1.9	3.3	3.4	3.4	3.4	16.3	17.5	17.1	17.0
Veridian Corp.	3.6	3.2	3.5	3.4 [2]					33.5	24.2	30.9	29.5 [2]
Gas Distributors												
Enbridge Gas Distribution	2.4	2.3	2.1	2.3	3.5	3.3	2.9	3.2	18.1	16.3	15.2	16.5
Gaz Métro L.P.	2.2	2.2	2.3	2.2	4.7	4.9	4.7	4.8	21.2	20.7	19.6	20.5
Pacific Northern Gas	2.6	2.1	2.2	2.3 [2]	2.6	2.3	2.0	2.3 [6]	11.7	11.2	9.5	10.8 [2]
Terasen Gas	1.9	1.9	1.9	1.9 [2]	2.6	2.5	2.4	2.5 [5]	10.3	9.8	8.8	9.6 [5]
Union Gas Limited	2.4	2.4	2.3	2.4	2.9	3.4	3.2	3.2	14.8	15.1	15.5	15.1
Pipelines												
Enbridge Pipelines Inc.	2.7	2.9	3.4	3.0	2.8	2.6	3.0	2.8	8.1	6.6	12.0	8.9
NOVA Gas Transmission Ltd.	2.0	2.2	2.4	2.2 [4]			3.2	3.2	14.2	14.2	20.1	16.2 [4]
Trans Québec & Maritimes Pipeline	3.5	2.1	2.0	2.5	4.4	3.6	2.4	3.5	20.2	15.8	8.3	14.8
TransCanada PipeLines Ltd.	1.9	2.3	2.3	2.2	2.8	3.0	2.9	2.9	12.4	13.0	14.4	13.3
Westcoast Energy Inc.	2.4	2.7	2.5	2.5	2.9	3.5	3.6	3.3	13.3	17.9	20.0	17.1
Medians												
Electric Utilities	**2.3**	**2.5**	**2.6**	**2.4**	**3.2**	**3.6**	**3.5**	**3.4**	**15.7**	**15.9**	**17.1**	**16.1**
Gas Distributors	**2.4**	**2.2**	**2.2**	**2.3**	**2.9**	**3.3**	**2.9**	**3.2**	**14.8**	**15.1**	**15.2**	**15.1**
Pipelines	**2.4**	**2.3**	**2.4**	**2.5**	**2.9**	**3.3**	**3.0**	**3.2**	**13.3**	**14.2**	**14.4**	**14.8**
All Companies	**2.4**	**2.3**	**2.3**	**2.3**	**3.1**	**3.4**	**3.3**	**3.3**	**14.7**	**15.5**	**16.2**	**15.8**
All Investor Owned Companies	**2.2**	**2.2**	**2.2**	**2.3**	**3.0**	**3.2**	**3.0**	**3.2**	**13.3**	**14.2**	**13.6**	**14.5**

[1] From S&P full analysis report for Hamilton Utilities.
[2] Data from DBRS.
[3] 2009 data from S&P Credit Stats.
[4] Data from S&P Credit Stats.
[5] Data from Moody's.
[6] Calculated from Annual Reports.

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

CREDIT METRICS OF U.S. ELECTRIC UTILITIES

	EBIT Coverage (X)				FFO Interest Coverage (X)				FFO To Debt (%)			
Company	**2009**	**2008**	**2007**	**3 Year Average**	**2009**	**2008**	**2007**	**3 Year Average**	**2009**	**2008**	**2007**	**3 Year Average**
ALLETE, Inc.	3.30	4.10	4.30	3.90	5.50	5.20	4.70	5.13	20.00	17.60	21.30	19.63
Alliant Energy Corporation	2.60	3.20	3.50	3.10	4.50	4.60	4.50	4.53	22.70	20.00	23.30	22.00
Dominion Resources, Inc.	3.20	3.40	1.90	2.83 [1]		3.90	0.50	2.20	22.20	16.70	-2.70	12.07 [1]
Duke Energy Corporation	3.30	3.00	3.70	3.33	5.20	5.30	6.50	5.67	21.00	23.50	32.50	25.67
IDACORP, Inc.	2.60	2.20	2.10	2.30	4.00	2.90	2.40	3.10	16.70	10.30	7.70	11.57
NextEra Energy, Inc.	3.50	3.50	3.20	3.40	6.30	5.80	6.30	6.13	24.00	23.10	33.00	26.70
OGE Energy Corp.	3.70	3.70	5.10	4.17	6.70	6.60	3.50	5.60	31.40	25.40	13.70	23.50
Portland General Electric Company	1.80	1.90	2.90	2.20 [1]		4.10	3.50	3.80	14.50	20.00	18.20	17.57 [1]
Progress Energy	2.40	2.40	2.50	2.43	3.60	2.90	3.80	3.43	16.10	12.10	16.40	14.87
SCANA Corporation	2.80	2.90	2.80	2.83	3.10	3.40	4.00	3.50	12.60	13.80	19.70	15.37
Sempra Energy	3.80	4.70	4.10	4.20 [1]					18.60	15.10	24.50	19.40 [1]
Southern Company	3.20	3.30	3.40	3.30	4.40	4.20	4.30	4.30	17.70	17.20	19.20	18.03
Vectren Corporation	2.90	3.10	3.00	3.00	5.00	5.10	4.00	4.70	21.40	21.20	17.90	20.17
Wisconsin Energy Corporation	2.20	1.10	2.90	2.07	4.70	4.90	4.30	4.63	16.70	18.40	16.70	17.27
Xcel Energy, Inc.	2.70	2.50	2.30	2.50	4.10	3.80	3.70	3.87	18.80	17.10	19.60	18.50
Medians												
All Companies	**2.90**	**3.10**	**3.00**	**3.00**	**4.60**	**4.40**	**4.00**	**4.42**	**18.80**	**17.60**	**19.20**	**18.50**

[1] 2009 data from S&P Credit Stats.

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

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1947-2010)

Stock Return	Bond Total Return	Risk Premium
12.1	6.9	5.2

Stock Return	Bond Income Return	Risk Premium
12.1	6.8	5.3

United States
(1947-2010)

Stock Return	Bond Total Return	Risk Premium
12.5	6.3	6.2

Stock Return	Bond Income Return	Risk Premium
12.5	5.9	6.6

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2010)

Stock Return	Bond Total Return	Risk Premium
11.7	6.5	5.2

Stock Return	Bond Income Return	Risk Premium
11.7	6.0	5.6

United States
(1926-2010)

Stock Return	Bond Total Return	Risk Premium
11.9	5.9	6.0

Stock Return	Bond Income Return	Risk Premium
11.9	5.2	6.7

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*

Schedule 8

FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
(Percentages)

Five Year Periods Ending:	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**2.86**	**4.35**	**4.88**	**4.88**	**4.57**
10 Sector Indices															
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.07	4.04	4.44
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.36	3.68	3.88
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	7.37	6.71	6.69
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	5.38	5.59	4.89
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	5.38	5.89	7.36
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.48	5.51	5.57
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	11.68	12.14	12.92
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	8.48	8.60	6.84
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	5.07	4.93	6.00
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.32	4.30	4.06
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.06**	**6.14**	**6.26**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.38**	**5.55**	**5.70**

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.74**	**0.71**	**0.71**	**0.70**	**0.65**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.80**	**0.77**	**0.72**

Source: *TSX Review*

Schedule 9

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49
2009	0.56	0.28	1.35	0.80	0.41	0.83	1.22	1.24	0.47	0.41
2010	0.55	0.33	1.24	0.85	0.39	0.87	1.37	1.22	0.46	0.42

Source: *TSX Review*

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS
(1956-2003)

	Sub-Index Compound Returns [1/]						Sub-Index Betas					
	56-03	56-97	64-73	74-83	84-93	94-03	56-03	56-97	64-73	74-83	84-93	94-03
Metals/Minerals	7.8	7.6	7.5	11.2	6.8	7.2	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	9.5	10.4	16.2	16.0	11.0	-2.7	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	9.5	8.4	14.6	11.9	4.5	15.3	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	7.1	7.4	4.8	11.8	10.3	2.6	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	11.3	11.9	10.2	13.8	11.2	9.6	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	7.2	9.6	8.3	10.9	6.0	1.1	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [2/]	5.3	5.5	0.7	16.7	-2.3	1.3	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	10.1	11.4	12.7	18.4	3.0	8.8	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	11.7	12.1	5.2	13.8	13.7	13.1	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	11.0	10.7	3.3	17.8	11.0	16.3	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	13.5	15.0	19.1	15.3	12.9	7.5	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	10.1	10.7	10.6	12.2	8.7	7.2	0.78	0.86	0.93	0.84	0.83	0.46
Finance	12.4	12.8	12.0	11.7	11.6	17.9	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	10.8	10.8	12.8	15.2	9.5	13.9	0.94	1.03	1.26	0.97	1.20	0.68
Adjusted R Square [3/]							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta [4/]							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Annualized rate of return at which capital has compounded over time.
[2/] Data only available starting July 1961
[3/] Represents percentage of variation in sub-index returns explained by the sub-index betas.
[4/] Represents relationship between sub-index returns and sub-index betas.

Source: *TSX Review*

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS
(1988-2010)

	Sector Compound Returns [1/]			Sector Betas		
	88-10	88-97	01-10	88-10	88-97	01-10
Consumer Discretionary	6.9	10.2	4.1	0.73	0.90	0.67
Consumer Staples	11.3	12.7	10.5	0.35	0.73	0.23
Energy	11.2	8.4	19.1	0.80	0.76	0.93
Financials	13.1	18.3	13.2	0.81	1.04	0.72
Health Care	4.9	15.5	-4.6	0.75	0.81	0.54
Industrials	6.4	8.3	7.0	0.94	1.13	0.97
Information Technology	5.7	21.8	-16.7	1.70	1.21	1.91
Materials	8.0	3.4	15.5	0.98	1.26	1.04
Telecommunication Services	12.6	15.4	4.5	0.68	0.58	0.57
Utilities	10.5	11.5	16.2	0.30	0.62	0.24
Adjusted R Square [2/]				**26%**	**1%**	**31%**
Beta [3/]				**-0.040**	**-0.017**	**-0.125**

[1/] Data only available starting December 1987. Annualized rate of return at which capital has compounded over time.
[2/] Represents percentage of variation in sector returns explained by the sector betas.
[3/] Represents relationship between sector returns and sector betas.

Source: *TSX Review*

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Canadian Utilities Limited	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.06	0.06
Emera Inc.	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.16	0.21
Enbridge Inc.	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.30	0.32
Fortis Inc.	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.20	0.16
Pacific Northern Gas	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54	0.35	0.26	0.44	0.39
Terasen Inc. [1/]	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na	na	na	na	na
TransCanada Corporation	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.39	0.39
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**	**0.48**	**0.25**	**0.26**	**0.26**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**	**0.53**	**0.24**	**0.25**	**0.27**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.41	0.42

Adjusted Betas [2/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Canadian Utilities Limited	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.37	0.37
Emera Inc.	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.44	0.47
Enbridge Inc.	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.53	0.54
Fortis Inc.	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.46	0.44
Pacific Northern Gas	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69	0.56	0.50	0.62	0.59
Terasen Inc. [1/]	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na	na	na	na	na
TransCanada Corporation	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.59	0.59
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**	**0.65**	**0.50**	**0.50**	**0.50**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**	**0.68**	**0.49**	**0.50**	**0.51**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.60	0.61

[1/] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.
[2/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

Monthly Betas and R^2s
Canadian Utilities

Beta	Canadian Utilities Limited		Emera Inc.		Enbridge Inc.		Fortis Inc.		Pacific Northern Gas		TransCanada Corp.		S&P/TSX Utilities	
Ending	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2
2004	0.03	0.1%	0.01	0.0%	-0.32	7.0%	0.01	0.0%	0.49	3.7%	-0.16	1.6%	-0.13	2.3%
2005	0.20	4.2%	0.07	0.5%	-0.19	2.8%	0.21	3.0%	0.54	4.9%	-0.15	2.5%	0.00	0.0%
2006	0.32	4.9%	0.12	1.1%	0.22	4.2%	0.48	9.0%	0.54	6.1%	0.34	10.0%	0.25	6.8%
2007	0.58	10.1%	0.24	3.2%	0.54	12.5%	0.65	11.8%	0.35	3.8%	0.52	14.8%	0.46	14.3%
2008	0.19	1.9%	0.17	3.5%	0.30	7.8%	0.21	2.8%	0.26	5.9%	0.38	16.4%	0.49	28.1%
2009	0.06	0.2%	0.16	3.3%	0.30	10.0%	0.20	2.9%	0.44	16.6%	0.39	19.7%	0.41	21.5%
2010	0.06	0.2%	0.21	4.9%	0.32	11.2%	0.16	2.3%	0.39	15.7%	0.39	19.1%	0.42	22.3%

Source: Standard and Poor's *Research Insight*

Schedule 12

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. ELECTRIC UTILITIES

	Value Line									S & P		Moody's
	Safety	Forecast Common Equity Ratio 2013-2015	Forecast Return On Average Common Equity 2013-2015	Dividend Payout Forecast 2013-2015	2010 Q4 Beta	"Raw" Weekly Betas[1/]	Adjusted Weekly Betas	Common Equity Ratio (Four Quarters ending 2010Q3)	2007-2009 Average Earned Returns	Business Risk Profile	Debt Rating	Debt Rating[2/]
ALLETE, Inc.	2	54.5%	9.5%	67.3%	0.70	0.60	0.73	56.9%	10.0%	Strong	BBB+	Baa1
Alliant Energy Corporation	2	51.5%	12.1%	53.3%	0.70	0.71	0.81	48.7%	10.1%	Excellent	BBB+	Baa1
Dominion Resources, Inc.	2	45.0%	14.2%	64.0%	0.70	0.59	0.73	40.3%	18.4%	Excellent	A-	Baa2
Duke Energy Corporation	2	50.0%	8.3%	70.0%	0.65	0.53	0.69	55.7%	5.8%	Excellent	A-	Baa2
IDACORP, Inc.	3	50.5%	8.7%	45.2%	0.70	0.59	0.73	49.1%	8.0%	Excellent	BBB	Baa2
NextEra Energy, Inc.	2	48.0%	12.0%	45.7%	0.75	0.67	0.78	40.3%	13.5%	Strong	A-	Baa1
OGE Energy Corp.	2	49.0%	13.0%	44.0%	0.75	0.77	0.85	45.4%	13.6%	Strong	BBB+	Baa1
Portland General Electric Co.	3	50.0%	8.6%	60.0%	0.75	0.59	0.72	46.5%	8.2%	Strong	BBB	Baa2
Progress Energy	2	47.0%	9.0%	72.7%	0.60	0.47	0.65	43.4%	8.0%	Excellent	BBB+	Baa2
SCANA Corporation	2	47.5%	10.1%	57.1%	0.70	0.57	0.71	41.9%	11.1%	Excellent	BBB+	Baa2
Sempra Energy	2	51.5%	9.6%	45.6%	0.85	0.74	0.82	50.7%	13.6%	Strong	BBB+	Baa1
Southern Company	1	44.5%	13.0%	70.0%	0.55	0.35	0.57	42.0%	13.3%	Excellent	A	Baa1
Vectren Corporation	2	50.5%	10.5%	66.7%	0.70	0.61	0.74	43.9%	10.5%	Excellent	A-	A3
Wisconsin Energy Corp.	2	49.5%	13.6%	51.4%	0.65	0.48	0.65	42.3%	11.1%	Excellent	BBB+	A3
Xcel Energy, Inc.	2	49.0%	10.2%	57.5%	0.65	0.48	0.66	44.8%	9.5%	Excellent	A-	Baa1
Mean	**2**	**49.2%**	**10.8%**	**58.0%**	**0.69**	**0.58**	**0.72**	**46.1%**	**11.0%**	**Excellent**	**BBB+**	**Baa1**
Median	**2**	**49.5%**	**10.2%**	**57.5%**	**0.70**	**0.59**	**0.73**	**44.8%**	**10.5%**	**Excellent**	**BBB+**	**Baa1**

[1/] "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending December 27, 2010). Duke prices begin in January 2007, Portland prices begin in May 2006.
[2/] Rating for Vectren Corp. is for Vectren Utility Holdings.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Invester-Owned Electric Utilities, Strongest To Weakes* t (October 6, 2010);
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (December 22, 2010);
Standard and Poor's Research Insight; *Value Line* (November and December 2010); *Value Line Index*, December 24, 2010; and

Schedule 13
Page 1 of 4

DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
CONSTANT GROWTH DCF MODEL

(Annual Averages of Monthly Data)

Year	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost of Equity	Long-Term Treasury Yield	Equity Risk Premium	Moody's Spread [2/]
1995	6.2	3.4	9.6	6.8	2.8	1.5
1996	5.8	3.6	9.4	6.7	2.7	1.4
1997	5.8	3.6	9.5	6.6	2.9	1.4
1998	5.2	3.9	9.1	5.5	3.5	1.7
1999	6.1	4.4	10.5	5.9	4.6	2.0
2000	5.8	5.5	11.3	5.9	5.4	2.5
2001	5.0	6.6	11.6	5.5	6.2	2.5
2002	5.7	7.0	12.7	5.4	7.3	2.6
2003	4.9	5.9	10.8	5.0	5.8	1.8
2004	4.2	5.1	9.3	5.1	4.2	1.3
2005	3.9	4.9	8.9	4.5	4.3	1.4
2006	3.9	6.1	10.0	4.9	5.1	1.4
2007	3.8	5.9	9.7	4.8	4.9	1.5
2008	4.5	6.6	11.0	4.2	6.8	3.1
2009	5.4	6.2	11.6	4.1	7.5	2.9
2010	4.8	5.7	10.5	4.2	6.3	1.7
Means for Long Treasury Yields:						
Below 4.0%	**5.0**	**6.0**	**11.0**	**3.6**	**7.4**	**3.3**
4.0-4.99%	**4.5**	**5.8**	**10.3**	**4.6**	**5.7**	**1.9**
Below 5.0%	**4.5**	**5.9**	**10.4**	**4.5**	**5.9**	**2.0**
5.0-5.99%	**5.1**	**5.5**	**10.6**	**5.5**	**5.1**	**2.0**
6.0-6.99%	**6.0**	**3.9**	**9.9**	**6.5**	**3.4**	**1.6**
7.0% and above	**6.2**	**3.4**	**9.7**	**7.3**	**2.4**	**1.3**
Means:						
1995 - 2010	**5.1**	**5.3**	**10.3**	**5.3**	**5.0**	**1.9**

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).
[2/] Moody's Spread is the yield on Moody's long-term Baa-rated Utility Index minus the long-term Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
CONSTANT GROWTH DCF MODEL**

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 11.66 - 1.25 (30-Year Treasury Yield)

t-statistics:
30-Year Treasury Yield = -14.03
R^2 = 51%

Equity Risk Premium at Long-Term Bond Yield of 4.5% **= 6.0%**

ROE at Long-Term Bond Yield of 4.5% **= 10.5%**

EQUATION 2:

Equity Risk Premium = 7.65 - 0.92 (30-Year Treasury Yield) + 1.16 (Spread)

Where Spread = Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
30-Year Treasury Yield = -13.08
Spread = 12.98

R^2 = 74%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% **= 5.4%**

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% **= 9.9%**

EQUATION 3:

Equity Risk Premium = 7.30 - 0.58 (Baa-rated Utility Bond Yields)

t-statistics:
Baa-rated Utility Bond Yield = -6.90
R^2 = 20%

Equity Risk Premium at Baa-rated Utility Bond Yield of 6.15% **= 3.7%**

ROE at A-rated Utility Bond Yield of 6.15% **= 9.9%**

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

**DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
THREE STAGE MODEL**

(Annual Averages of Monthly Data)

Year	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost of Equity	Long-Term Treasury Yield	Equity Risk Premium	Moody's Spread [2/]
1995	6.2	3.4	11.0	6.8	4.2	1.5
1996	5.8	3.6	10.1	6.7	3.4	1.4
1997	5.8	3.6	10.3	6.6	3.8	1.4
1998	5.2	3.9	9.7	5.5	4.1	1.7
1999	6.1	4.4	10.7	5.9	4.8	2.0
2000	5.8	5.5	11.0	5.9	5.1	2.5
2001	5.0	6.6	10.8	5.5	5.3	2.5
2002	5.7	7.0	11.6	5.4	6.2	2.6
2003	4.9	5.9	10.5	5.0	5.5	1.8
2004	4.2	5.1	9.6	5.1	4.5	1.3
2005	3.9	4.9	9.3	4.5	4.7	1.4
2006	3.9	6.1	9.5	4.9	4.6	1.4
2007	3.8	5.9	9.1	4.8	4.3	1.5
2008	4.5	6.6	9.8	4.2	5.6	3.1
2009	5.4	6.2	10.8	4.1	6.7	2.9
2010	4.8	5.7	9.9	4.2	5.8	1.7
Means for Long Treasury Yields:						
Below 4.0%	**5.0**	**6.0**	**10.3**	**3.6**	**6.7**	**3.3**
4.0-4.99%	**4.5**	**5.8**	**9.8**	**4.6**	**5.2**	**1.9**
Below 5.0%	**4.5**	**5.9**	**9.9**	**4.5**	**5.4**	**2.0**
5.0-5.99%	**5.1**	**5.5**	**10.4**	**5.5**	**4.9**	**2.0**
6.0-6.99%	**6.0**	**3.9**	**10.6**	**6.5**	**4.1**	**1.6**
7.0% and above	**6.2**	**3.4**	**10.9**	**7.3**	**3.6**	**1.3**
Means:						
1995 - 2010	**5.1**	**5.3**	**10.2**	**5.3**	**4.9**	**1.9**

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).
[2/] Moody's Spread is the yield on Moody's long-term Baa-rated Utility Index minus the long-term Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
THREE STAGE MODEL

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 8.67 - 0.71 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -11.99

R^2 = 43%

Equity Risk Premium at Long-Term Bond Yield of 4.50% = 5.5%

ROE at Long-Term Bond Yield of 4.50% = 10.0%

EQUATION 2:

Equity Risk Premium = 6.17 - 0.50 (30-Year Treasury Yield) + 0.72 (Spread)

Where Spread = Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -10.25

Spread = 11.62

R^2 = 67%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% = 5.1%

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% = 9.6%

EQUATION 3:

Equity Risk Premium = 6.10 - 0.43 (Baa-rated Utility Bond Yields)

t-statistics:

A-rated Utility Bond Yield = -9.39

R^2 = 32%

Equity Risk Premium at Baa-rated Utility Bond Yield of 6.15% = 3.5%

ROE at Baa-rated Utility Bond Yield of 6.15% = 9.6%

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

APPROVED U.S. ELECTRIC AND GAS UTILITY ROES, RISK PREMIUMS, BOND YIELDS AND SPREADS

	Approved Electric and Gas ROEs	Moody's Baa Utility Bond	30-Year Treasury Yield	Baa Utility/ Treasury Yield Spread	Allowed ROE Risk Premium Over Baa Utility Bond		Approved Electric and Gas ROEs	Moody's Baa Utility Bond	30-Year Treasury Yield	Baa Utility/ Treasury Yield Spread	Allowed ROE Risk Premium Over Baa Utility Bond
1994 Q3		8.84	7.56	1.28		2002 Q4	10.94	7.71	5.11	2.59	3.24
1994 Q4		9.25	7.95	1.30		2003 Q1	11.43	7.11	4.93	2.18	4.32
1995 Q1	11.96	8.95	7.54	1.42	3.01	2003 Q2	11.26	6.49	4.71	1.79	4.77
1995 Q2	11.32	8.33	6.88	1.45	3.00	2003 Q3	10.28	6.92	5.28	1.64	3.36
1995 Q3	11.24	8.11	6.67	1.44	3.13	2003 Q4	10.93	6.69	5.22	1.47	4.24
1995 Q4	11.55	7.75	6.15	1.61	3.79	2004 Q1	11.06	6.26	4.96	1.29	4.80
1996 Q1	11.37	7.86	6.39	1.46	3.51	2004 Q2	10.47	6.69	5.39	1.29	3.78
1996 Q2	11.23	8.43	6.93	1.50	2.80	2004 Q3	10.36	6.42	5.08	1.34	3.94
1996 Q3	10.96	8.37	7.01	1.35	2.59	2004 Q4	10.80	6.18	4.93	1.25	4.62
1996 Q4	11.44	8.00	6.56	1.44	3.44	2005 Q1	10.54	5.92	4.70	1.22	4.62
1997 Q1	11.31	8.15	6.90	1.25	3.15	2005 Q2	10.25	5.75	4.36	1.39	4.50
1997 Q2	11.64	8.27	6.89	1.38	3.37	2005 Q3	10.63	5.79	4.39	1.40	4.84
1997 Q3	12.00	7.88	6.44	1.44	4.12	2005 Q4	10.55	6.14	4.63	1.50	4.42
1997 Q4	11.04	7.52	6.04	1.48	3.52	2006 Q1	10.55	6.20	4.70	1.50	4.35
1998 Q1	11.31	7.34	5.89	1.44	3.97	2006 Q2	10.64	6.63	5.19	1.44	4.00
1998 Q2	11.58	7.31	5.79	1.51	4.27	2006 Q3	10.18	6.34	4.91	1.43	3.84
1998 Q3	11.57	7.19	5.33	1.86	4.38	2006 Q4	10.31	6.07	4.70	1.37	4.24
1998 Q4	11.75	7.23	5.11	2.12	4.52	2007 Q1	10.36	6.16	4.82	1.34	4.20
1999 Q1	10.68	7.42	5.43	1.99	3.26	2007 Q2	10.23	6.32	4.98	1.34	3.91
1999 Q2	10.89	7.76	5.83	1.93	3.13	2007 Q3	10.03	6.45	4.86	1.59	3.57
1999 Q3	10.63	8.11	6.08	2.03	2.52	2007 Q4	10.42	6.38	4.53	1.85	4.04
1999 Q4	10.76	8.24	6.31	1.93	2.52	2008 Q1	10.42	6.59	4.35	2.24	3.83
2000 Q1	11.00	8.38	6.16	2.22	2.63	2008 Q2	10.46	6.85	4.58	2.27	3.61
2000 Q2	11.09	8.58	5.96	2.61	2.51	2008 Q3	10.48	7.22	4.44	2.78	3.26
2000 Q3	11.43	8.30	5.78	2.52	3.13	2008 Q4	10.34	8.59	3.50	5.09	1.75
2000 Q4	12.25	8.18	5.62	2.57	4.06	2009 Q1	10.27	7.95	3.62	4.34	2.32
2001 Q1	11.23	7.93	5.45	2.48	3.31	2009 Q2	10.35	7.48	4.24	3.24	2.88
2001 Q2	10.84	8.12	5.77	2.35	2.72	2009 Q3	10.23	6.21	4.17	2.03	4.02
2001 Q3	10.78	7.98	5.44	2.54	2.80	2009 Q4	10.41	6.16	4.35	1.80	4.26
2001 Q4	11.29	7.96	5.21	2.75	3.32	2010 Q1	10.51	6.17	4.59	1.58	4.34
2002 Q1	10.80	8.27	5.66	2.61	2.53	2010 Q2	10.04	6.05	4.22	1.83	3.99
2002 Q2	11.50	8.24	5.72	2.52	3.26	2010 Q3	10.17	5.54	3.73	1.81	4.64
2002 Q3	11.25	7.73	5.13	2.60	3.52	2010 Q4	10.21	5.79	4.15	1.64	4.42

Sources: www.federalreserve.gov; www.moodys.com; Regulatory Research Associates at www.snl.com; www.ustreas.gov

Schedule 14
Page 2 of 2

APPROVED ROEs FOR U.S. ELECTRIC AND GAS UTILITIES

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 8.59 - 0.58 (6 Months Lagged 30-Year Treasury Yield)

t-statistics:
6 Months Lagged 30-Year Treasury Yield = 12.66
R^2 = 72%

Equity Risk Premium at Long-Term Bond Yield of 4.50% = 6.0%

ROE at Long-Term Bond Yield of 4.50% = 10.5%

EQUATION 2:

Equity Risk Premium = 7.90 - 0.52 (6 Months Lagged 30-Year Treasury Yield) + 0.19 (Spread)

Where Spread = 6 Months Lagged Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -10.97
Spread = 3.00

R^2 = 76%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% = 5.9%

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% = 10.4%

EQUATION 3:

Equity Risk Premium = 7.89 - 0.59 (6 Months Lagged Moody's Baa-Rated)

t-statistics:
6 Months Lagged Baa-Rated Utility Bond Yield = -11.51

R^2 = 68%

Equity Risk Premium at Baa-Rated Utility Bond Yield of 6.15% = 4.2%

ROE at Baa-Rated Utility Bond Yield of 6.15% = 10.4%

HISTORIC UTILITY EQUITY RISK PREMIUMS
(Arithmetic Averages)

Canada
(1956-2010)

Utilities Index Return	Bond Total Return	Risk Premium
12.2	7.7	4.5

Utilities Index Return	Bond Income Return	Risk Premium
12.2	7.4	4.8

United States
(1947-2010)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
10.8	6.3	4.5

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
10.8	5.9	4.9

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.8	6.3	5.6

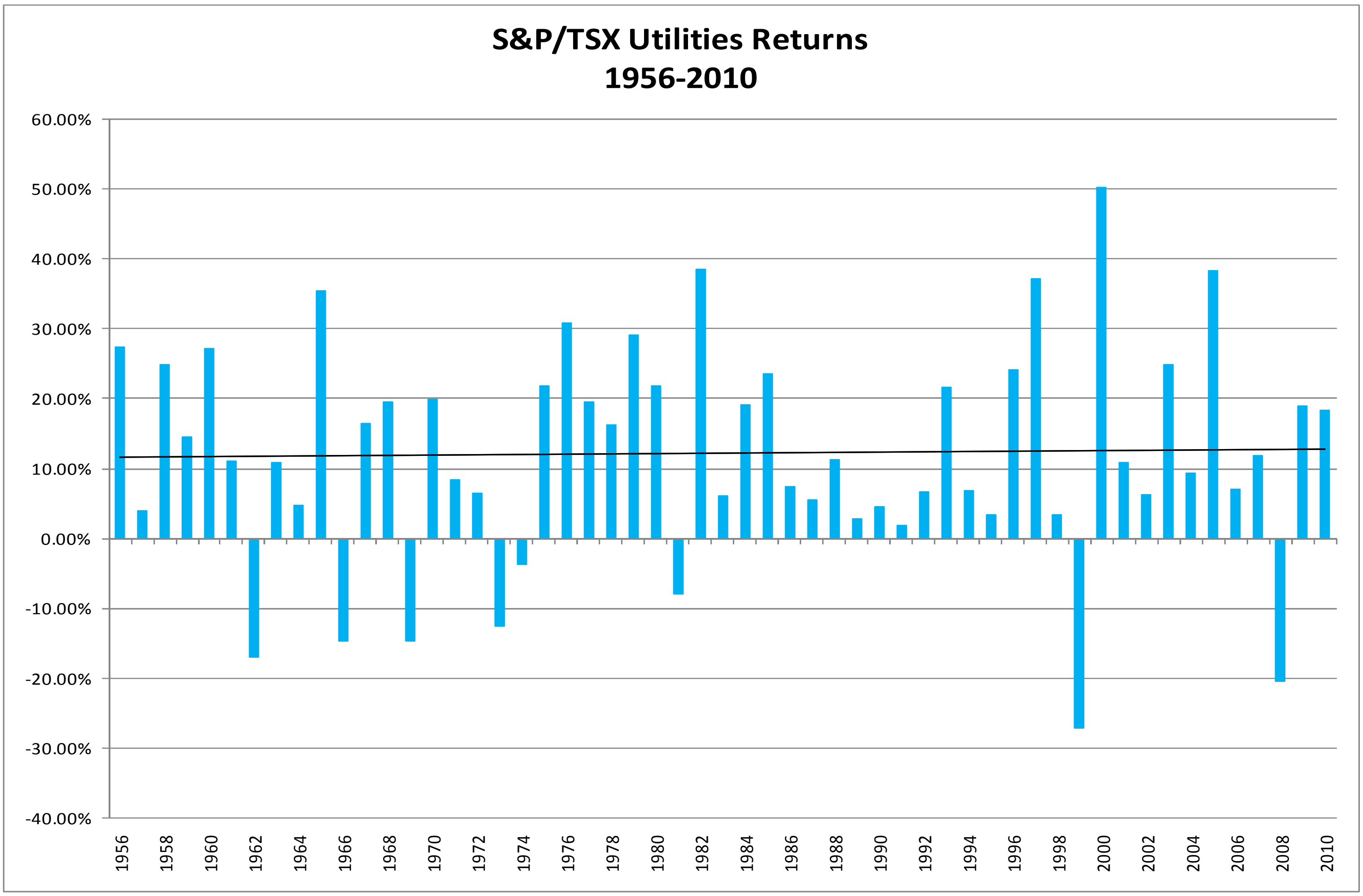
S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.8	5.9	5.9

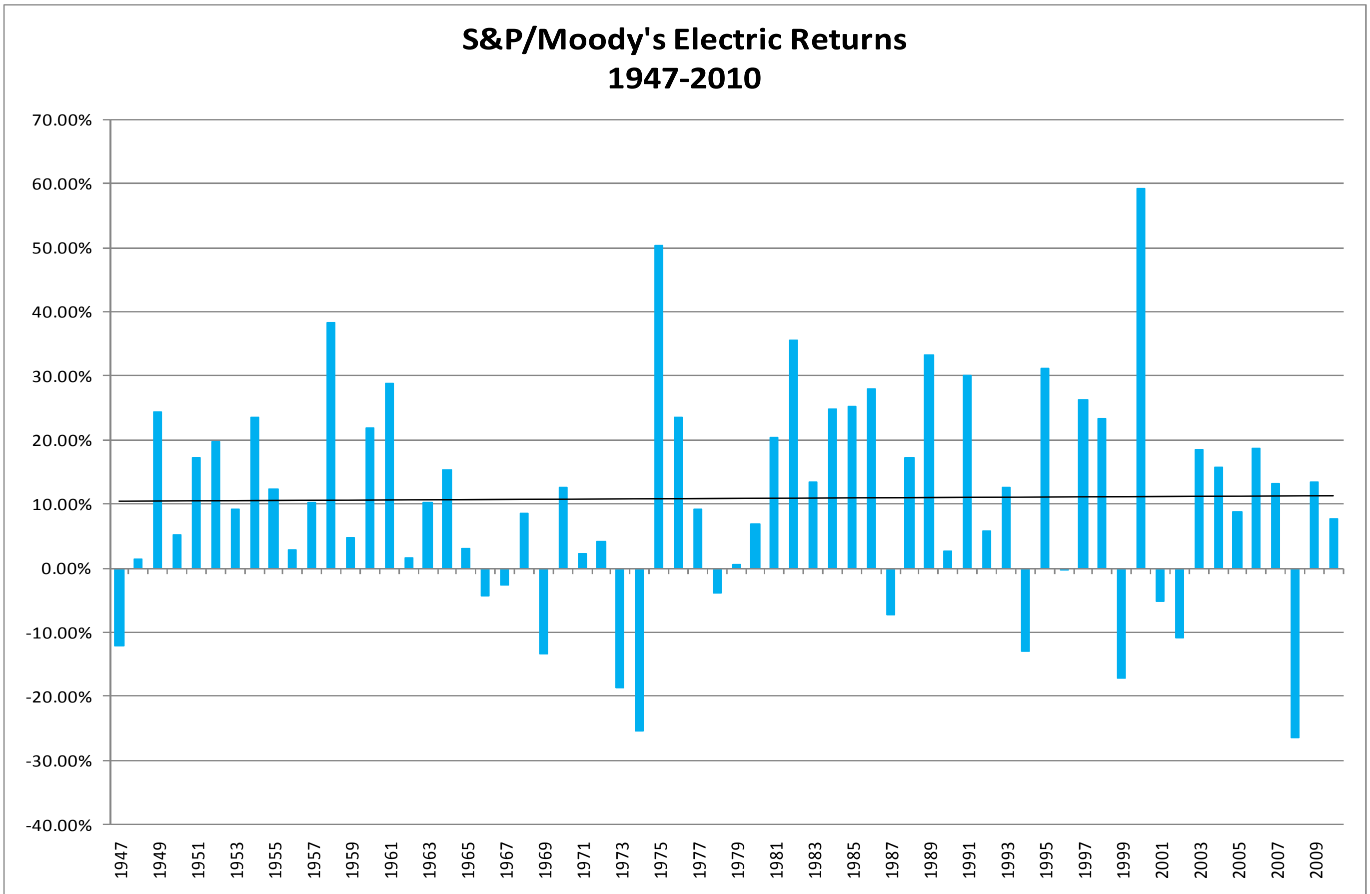
Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2010.

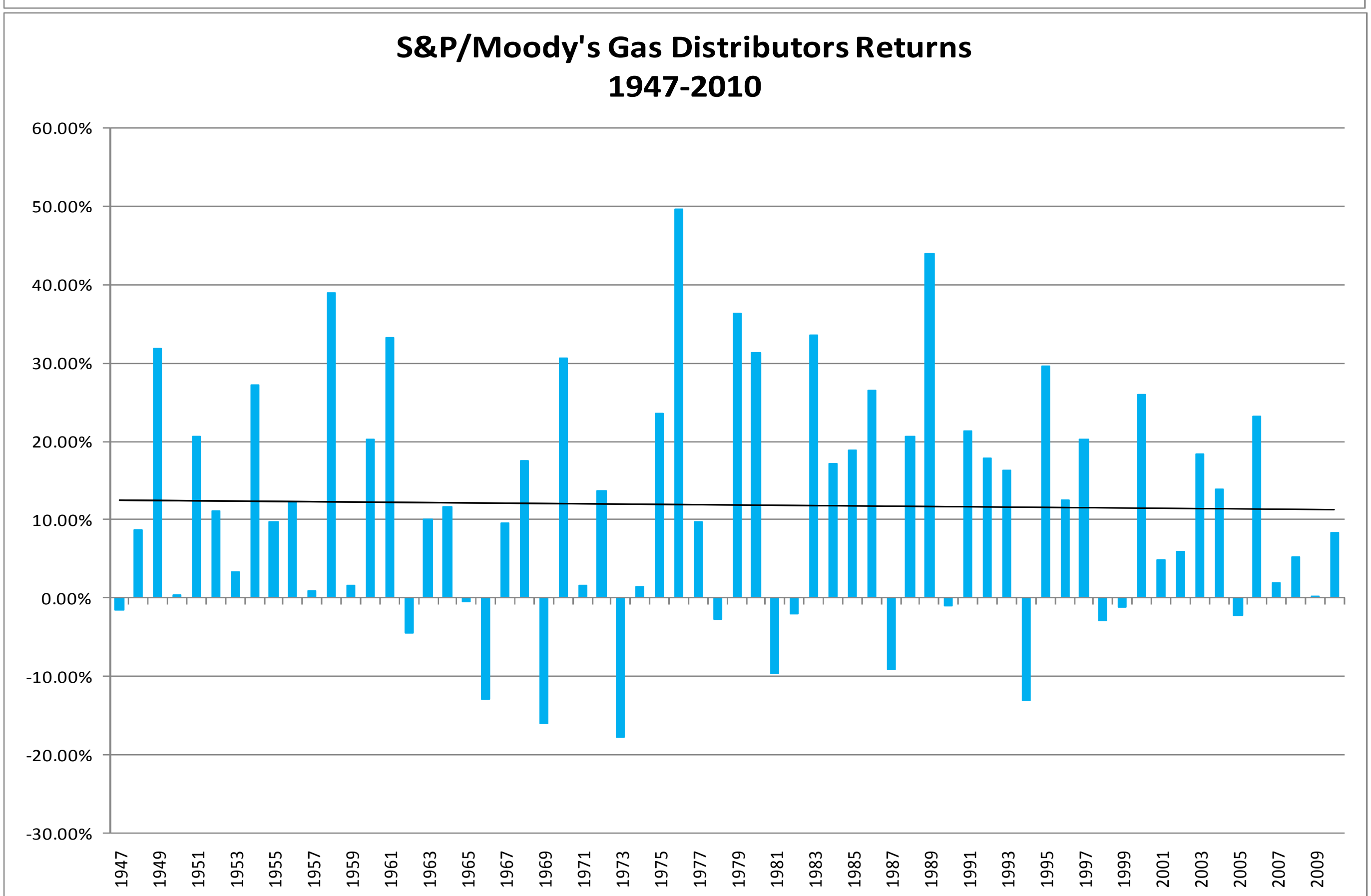
The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2010 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2010 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*


S&P/TSX Utilities Returns
1956-2010
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1956
1958
1960
1962
1964
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010


S&P/Moody's Electric Returns
1947-2010
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1947
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009


S&P/Moody's Gas Distributors Returns
1947-2010
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
1947
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009

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

Company	Annualized Last Paid Dividend	Average Daily Close Prices 10/1/2010-12/31/2010	Expected Dividend Yield [1/]	Analysts' Long-Term Earnings Growth Forecasts: I/B/E/S	Value Line	Reuters	Zacks	Average of All EPS Estimates	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(5)
ALLETE, Inc.	1.76	36.43	5.0	5.3	1.0	5.3	4.0	3.9	8.9
Alliant Energy Corporation	1.58	36.63	4.6	9.6	7.0	7.1	3.5	6.8	11.4
Dominion Resources, Inc.	1.83	43.14	4.5	3.5	6.5	6.5	3.4	5.0	9.4
Duke Energy Corporation	0.98	17.77	5.7	4.4	5.0	5.6	1.3	4.1	9.8
IDACORP, Inc.	1.20	36.76	3.4	4.7	5.5	4.7	4.7	4.9	8.3
NextEra Energy, Inc.	2.00	53.18	4.0	6.6	5.5	6.5	6.4	6.3	10.3
OGE Energy Corp.	1.45	44.40	3.5	7.0	6.5	5.8	5.5	6.2	9.7
Portland General Electric Company	1.04	21.28	5.1	5.4	3.0	5.3	5.6	4.8	9.9
Progress Energy	2.48	44.22	5.8	3.7	3.5	3.7	4.0	3.7	9.5
SCANA Corporation	1.90	40.91	4.8	4.8	3.5	4.7	3.8	4.2	9.0
Sempra Energy	1.56	52.25	3.1	6.6	0.0	6.5	8.5	5.4	8.5
Southern Company	1.82	37.98	5.0	5.3	4.5	5.3	4.8	5.0	10.0
Vectren Corporation	1.38	26.26	5.5	4.8	4.5	4.8	5.0	4.8	10.3
Wisconsin Energy Corporation	1.60	59.22	3.0	10.1	9.5	8.8	8.5	9.2	12.2
Xcel Energy, Inc.	1.01	23.65	4.5	6.7	5.5	6.1	5.5	5.9	10.4
Mean	**1.57**	**38.27**	**4.5**	**5.9**	**4.7**	**5.8**	**5.0**	**5.3**	**9.9**
Median	**1.58**	**37.98**	**4.6**	**5.3**	**5.0**	**5.6**	**4.8**	**5.0**	**9.8**

[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: www.reuters.com, Standard and Poor's *Research Insight* , *Value Line* (November and December 2010), www.yahoo.com, and www.zacks.com.

Schedule 17

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

Company	Annualized Last Dividend Paid	Average Daily Close Prices 10/1/2010-12/31/2010	Expected Dividend Yield [1/]	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth [2/] (4th Qtr.2010)	SV Growth [3/] (4th Qtr. 2010)	Sustainable Growth [4/] (4th Qtr. 2010)	DCF Cost of Equity [5/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ALLETE, Inc.	1.76	36.43	5.0	9.5	32.7	3.1	0.33	3.4	8.4
Alliant Energy Corporation	1.58	36.63	4.6	12.1	46.7	5.6	0.34	6.0	10.6
Dominion Resources, Inc.	1.83	43.14	4.5	14.2	36.0	5.1	-0.07	5.1	9.5
Duke Energy Corporation	0.98	17.77	5.7	8.3	30.0	2.5	0.05	2.5	8.2
IDACORP, Inc.	1.20	36.76	3.4	8.7	54.8	4.8	0.14	4.9	8.3
NextEra Energy, Inc.	2.00	53.18	4.0	12.0	54.3	6.5	0.54	7.0	11.1
OGE Energy Corp.	1.45	44.40	3.5	13.0	56.0	7.3	0.19	7.4	11.0
Portland General Electric Company	1.04	21.28	5.1	8.6	40.0	3.4	0.18	3.6	8.7
Progress Energy	2.48	44.22	5.8	9.0	27.3	2.5	0.08	2.5	8.3
SCANA Corporation	1.90	40.91	4.9	10.1	42.9	4.3	0.79	5.1	10.0
Sempra Energy	1.56	52.25	3.1	9.6	54.4	5.2	-0.12	5.1	8.3
Southern Company	1.82	37.98	5.0	13.0	30.0	3.9	0.79	4.7	9.7
Vectren Corporation	1.38	26.26	5.5	10.5	33.3	3.5	0.36	3.9	9.3
Wisconsin Energy Corporation	1.60	59.22	2.9	13.6	48.6	6.6	0.00	6.6	9.5
Xcel Energy, Inc.	1.01	23.65	4.5	10.2	42.5	4.3	0.32	4.7	9.1
Mean	**1.57**	**38.27**	**4.49**	**10.83**	**41.97**	**4.58**	**0.26**	**4.8**	**9.3**
Median	**1.58**	**37.98**	**4.57**	**10.22**	**42.50**	**4.35**	**0.19**	**4.9**	**9.3**

[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: Standard and Poors *Research Insight*, *Value Line* (November and December 2010) , www.yahoo.com.

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

			Growth Rates			
Company	**Annualized Last Paid Dividend**	**Average Daily Close Prices 10/1/2010-12/31/2010**	**Stage 1: Average of All EPS Forecasts**	**Stage 2: Average of Stage 1 & 3**	**Stage 3: GDP Growth** [1/]	**DCF Cost of Equity** [2/]
	(1)	(2)	(3)	(4)		(5)
ALLETE, Inc.	1.76	36.43	3.9	4.4	4.9	9.6
Alliant Energy Corporation	1.58	36.63	6.8	5.9	4.9	9.9
Dominion Resources, Inc.	1.83	43.14	5.0	4.9	4.9	9.3
Duke Energy Corporation	0.98	17.77	4.1	4.5	4.9	10.4
IDACORP, Inc.	1.20	36.76	4.9	4.9	4.9	8.2
NextEra Energy, Inc.	2.00	53.18	6.3	5.6	4.9	9.1
OGE Energy Corp.	1.45	44.40	6.2	5.5	4.9	8.5
Portland General Electric Company	1.04	21.28	4.8	4.9	4.9	10.0
Progress Energy	2.48	44.22	3.7	4.3	4.9	10.3
SCANA Corporation	1.90	40.91	4.2	4.5	4.9	9.5
Sempra Energy	1.56	52.25	5.4	5.2	4.9	8.0
Southern Company	1.82	37.98	5.0	4.9	4.9	9.9
Vectren Corporation	1.38	26.26	4.8	4.8	4.9	10.3
Wisconsin Energy Corporation	1.60	59.22	9.2	7.1	4.9	8.5
Xcel Energy, Inc.	1.01	23.65	5.9	5.4	4.9	9.6
Mean	**1.57**	**38.27**	**5.3**	**5.1**	**4.9**	**9.4**
Median	**1.58**	**37.98**	**5.0**	**4.9**	**4.9**	**9.6**

[1/] Forecast nominal rate of GDP growth, 2012-21

[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: Blue Chip *Financial Forecasts* (December 2010), www.reuters.com, Standard and Poor's *Research Insight*, *Value Line* (November and December 2010), www.yahoo.com, and www.zacks.com.

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

Company	Annualized Last Paid Dividend (1)	Average Daily Close Prices 10/1/2010-12/31/2010 (2)	Expected Dividend Yield [1/] (3)	I/B/E/S/ Long-Term EPS Forecasts (4)	Bloomberg Long-Term EPS Forecasts (5)	Average of EPS Estimates (6)	DCF Cost of Equity [2/] (7)
Canadian Utilities Limited	1.51	50.83	3.0	-2.6	3.0	0.2	3.2
Emera Inc.	1.30	30.96	4.5	5.0	7.0	6.0	10.5
Enbridge Inc.	1.70	55.87	3.3	8.2	9.2	8.7	12.0
Fortis Inc.	1.12	32.62	3.7	7.2	8.0	7.6	11.3
TransCanada Corp.	1.60	37.60	4.5	6.0	6.0	6.0	10.5
Mean	**1.45**	**41.58**	**3.8**	**4.8**	**6.6**	**5.7**	**9.5**
Median	**1.51**	**37.60**	**3.7**	**6.0**	**7.0**	**6.0**	**10.5**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (6))
[2/] Expected Dividend Yield (Col (3)) + Average of EPS Estimates (Col (6))

Source: Bloomberg; Standard and Poor's *Research Insight* ; and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES (THREE-STAGE MODEL)

			Growth Rates			
Company	Annualized Last Paid Dividend (1)	Average Daily Close Prices 10/1/2010-12/31/2010 (2)	Stage 1: Average of EPS Forecasts (3)	Stage 2: Average of Stage 1 & 3 (4)	Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/] (5)
Canadian Utilities Limited	1.51	50.83	0.2	2.4	4.6	6.6
Emera Inc.	1.30	30.96	6.0	5.3	4.6	9.3
Enbridge Inc.	1.70	55.87	8.7	6.6	4.6	8.6
Fortis Inc.	1.12	32.62	7.6	6.1	4.6	8.8
TransCanada Corp.	1.60	37.60	6.0	5.3	4.6	9.4
Mean	**1.45**	**41.58**	**5.7**	**5.1**	**4.6**	**8.5**
Median	**1.51**	**37.60**	**6.0**	**5.3**	**4.6**	**8.8**

[1/] Forecast nominal rate of GDP growth, 2011-20

[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; Consensus Economics *Consensus Forecasts* (October 2010); Standard and Poor's *Research Insight* ; and www.yahoo.com.

Schedule 21

MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES SAMPLE

	Debt and Preferred Shares at Par in Millions $ (September 2010)	Common Share Price Average Daily Close 10/1/2010-12/31/2010	Common Shares Outstanding in Millions (September 2010)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
Canadian Utilities Limited	3,722	50.83	126	6,396	63.2%
Emera Inc.	3,186	30.96	114	3,523	52.5%
Enbridge Inc.	13,613	55.87	384	21,452	61.2%
Fortis Inc.	6,787	32.62	174	5,663	45.5%
TransCanada Corp.	22,294	37.60	692	26,018	53.9%
Mean				**$12,610**	**55.2%**
Median				**$6,396**	**53.9%**

MARKET VALUE CAPITAL STRUCTURES FOR U.S. ELECTRIC UTILITIES SAMPLE

	Debt and Preferred Shares at Par in Millions $ (September 2010)	Common Share Price Average Daily Close 10/1/2010-12/31/2010	Common Shares Outstanding in Millions (September 2010)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
ALLETE, Inc.	787	36.43	34	1,242	61.2%
Alliant Energy Corporation	2,949	36.63	110	4,046	57.8%
Dominion Resources, Inc.	17,156	43.14	585	25,237	59.5%
Duke Energy Corporation	18,004	17.77	1320	23,454	56.6%
IDACORP, Inc.	1,619	36.76	48	1,768	52.2%
NextEra Energy, Inc.	20,468	53.18	411	21,851	51.6%
OGE Energy Corp.	2,597	44.40	97	4,325	62.5%
Portland General Electric Company	1,828	21.28	75	1,602	46.7%
Progress Energy	12,734	44.22	294	13,000	50.5%
SCANA Corporation	4,831	40.91	127	5,180	51.7%
Sempra Energy	9,110	52.25	247	12,887	58.6%
Southern Company	21,193	37.98	836	31,750	60.0%
Vectren Corporation	1,796	26.26	81	2,132	54.3%
Wisconsin Energy Corporation	4,957	59.22	117	6,923	58.3%
Xcel Energy, Inc.	9,424	23.65	460	10,889	53.6%
Mean				**$11,086**	**55.7%**
Median				**$6,923**	**56.6%**

Source: Reports to Shareholders, www.yahoo.com

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES:

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, but

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

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

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for Baa rated utility
	=	5.00%
Equity Cost	=	9.30%
Tax Rate	=	28.0%
CEQ Ratio	Step (1)	55.0%
Debt Ratio	Step (1)	45.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 55.0%)

   $WACC_{AT}$ = (5.00%)(1-.280)(45.0%) + (9.30%)(55.0%)
   = 6.74%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio with $WACC_{AT}$ unchanged at 6.74%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   6.74% = (5.00%)(1-.280)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 11.44%

3. Difference between Equity Return at 55.0% and 40.0% common equity ratios:

   11.44% - 9.30% = 2.14% (214 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 Baa rated utility
	=	5.00%
Equity Cost	=	9.30%
Tax Rate	=	28.0%
CEQ Ratio	Step (1)	55.0%
Debt Ratio	Step (1)	45.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 55.0%)

$WACC_{AT}$ = (5.00%)(1-.280)(45.0%) + (9.30%)(55.0%)
= 6.74%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

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

$$WACC_{AT(ML)} = 6.74\% \times \frac{(1-.280 \times 60.0\%)}{(1-.280 \times 45.0\%)}$$

$WACC_{AT(ML)}$ = 6.41%

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

$WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt Ratio_{ML}) + (Equity Cost)(Equity Ratio_{ML})
6.41% = (5.00%)(1-.280)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 10.63%

4. Difference between Equity Return at 55.0% and 40.0% common equity ratios:

10.63% - 9.30% = 1.33% (133 basis points)

Nova Scotia Utility and Review Board

Nova Scotia Power Incorporated

2011
UNMETERED CLASS
COST OF SERVICE AND PRICING STUDY REVIEW

DATED: May 2011

Table of Contents

1.0 INTRODUCTION

This report is filed in support of NSPI's General Rate Case Application (GRA), which proposes a change in the ratemaking methodology used for pricing of unmetered services.

The proposed changes are motivated by the anticipated large scale deployment of LED streetlights (streetlight), which will replace the current streetlights over the next 5 years.

What follows is a discussion of the rationale behind the proposed changes to rates and the outline of the proposed methodology supported by calculations.

1.1 Unmetered Services at NSPI in General

The unmetered class includes three distinct service categories:

1. electric service only applicable to both streetlight and miscellaneous loads,
2. electric service combined with streetlight fixture maintenance, and
3. 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 to meter 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. A streetlight rate reflective of all three services combined is referred to as a full charge rate. Where the customer owns the fixture and NSPI 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 few hundred customized rates.

2.0 CURRENT RATEMAKING METHODOLOGY FOR UNMETERED SERVICES

The Ratemaking methodology for Unmetered Services has essentially remained unchanged since Street and Crosswalk Lighting rates were developed, based on a 1977 Street/Crosswalk Lighting Study. The only changes that have affected this class were from the introduction of the Fuel Adjustment Mechanism (FAM) and Demand Side Management (DSM) riders.

The ratemaking methodology is comprised of two distinct steps:

1) Determination of cost responsibilities of this entire class using a COSS methodology and;
2) Determination of revenue responsibilities of each service category by implementing the formula-based revenue allocation process as approved by the Board.

In the last two GRA proceedings, the combined revenue responsibilities of all three types of services under this class have been set equal to the allocated costs in COSS. However, while the revenues associated with fixture maintenance services were set at costs, the revenue responsibilities for electric and fixture capital services were not. The fixture capital-related revenues were set above costs. This resulted in the subsidy of electricity costs paid by all ratepayers under this class.

2.1 Cost of Service Studies (COSS)

NSPI's Cost of Service Study (COSS) provides an indicator as to how the current and proposed rates and resulting revenue compare to the costs assigned to the various customer classes.

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 on 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 are determined using COSS-based cost allocation methodology.

In the case of depreciation costs and grants in lieu of taxes, the allocation is based on customer utilization of the entire distribution net plant. Under the ordinary operating environment of recurring costs and stable net plant value, the above allocation approach is sufficient. In situations of a significant investment in a particular distribution asset, which is not utilized evenly by various customer classes, however is grouped with other assets for the cost allocation purposes, the above approach may fail to allocate depreciation costs accurately. This will happen because the depreciation cost is a function of the asset's gross plant value, as opposed to its net plant value. Thus, the current COSS methodology is not an appropriate mechanism for the equitable allocation of depreciation costs of LED assets, which are to be deployed on a large scale over a short time horizon. Further, with the streetlight fixture depreciation cost information being directly available from NSPI's financial information system, there is a more accurate way to assign this direct cost to non-LED streetlight customers, than by employing net plant value based allocators.

2.2 Pricing of Unmetered Services

The Streetlight Study, which focuses on determining capital and maintenance costs, is generally conducted independently of the Company's regular Cost of Service study. Certain service-related costs, allocated to the unmetered class in the COSS, such as streetlight operating and maintenance expenses, are used directly to set revenue responsibility for this service. Thus, the fixture maintenance charges are aligned with costs of these services. The charges for electric and fixture capital services are not aligned with costs. The charges for capital service are set based on a marginal cost of capital substitution formula that produces higher capital cost results, in general, than those estimated in COSS using the embedded cost approach.[1] The resulting imbalance between costs and revenue in this category is rolled over to electric service rates. This approach has historically worked because the electric service cost has accounted for a much bigger share of the total cost of service (close to 60%) than the capital related costs of non-LED fixtures, as measured in the COSS (less than 20% of the total cost).

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

[1] The formula is discussed in schedule 4 of Appendix A.

one demand charge and two declining energy charges, applicable to energy blocks whose sizes vary with metered demand.[2] The rates are changed only through GRA proceedings; however they can be, and are, used by NSPI 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 UARB.

3.0 NEW OPERATING ENVIRONMENT

The deployment of LED streetlights will change the operational and costing environment in which the rates for these services are set. The recurring and predictable nature of the streetlight costs will give way to rapidly changing capital expenditures. The relative cost shares of the three basic services included in the unmetered class (energy, maintenance and capital) will shift. As capital-intensive LED technology displaces current energy-intensive streetlight technologies, the relative share of capital-related costs will eventually exceed that of energy. Further, the maintenance costs associated with bulb changes are expected to be greatly reduced or disappear altogether. The LED investment will produce long-term savings in avoided fuel and deferred infrastructure costs that will benefit all ratepayers.

3.1 Current Ratemaking Methodology in the New Environment

3.1.1 Unsustainable Ratemaking Results Going Forward

In comparison to current light fixtures (i.e. high pressure sodium), LED streetlights have lower energy costs and higher capital costs. As LED assets are depreciated, the continued application of the marginal cost of capital substitution formula in setting rates for capital services, as predicated on asset gross plant value, will expand the gap between revenues and costs of capital. This will drive the amount of revenue to be collected in this class for the consumption of electricity down as total revenues collected from this class must match its total costs of service. Consequently, the price paid by all the unmetered customers for electricity will drop significantly below its costs. NSPI estimates that

[2] 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.

during the second half of the LED asset's "useful life", using the current methodology would produce electricity prices below zero.

In contrast to the rapid LED deployment, the non-LED fixtures were installed gradually. With the passage of time the combined net plant value of the non-LED streetlight fixtures leveled off, at about half of its gross plant value, leading to a stable pricing environment.

3.1.2 Price Signals to Streetlight Customers

Overpriced capital and underpriced electric service would produce undesirable consequences from the perspective of energy conservation and recovery of utility costs. Customers would be incented to switch to self-financing options to take advantage of underpriced electricity and to avoid over-priced capital services. Admittedly, these pricing signals are in effect today, however under the current energy-intensive non-LED technology they are not as prevalent as they would be under the capital intensive LED streetlight.

Aligning rates with costs for capital services may not be free from problems. Given that the streetlight fixture assets are not shared with any other customer classes, the LED fixture rates would start off at a high level during the initial period of asset depreciation and then eventually would decrease, leveling off at a near depreciation cost level, only at the end of the asset's useful life.

4.0 PROPOSED RATEMAKING SOLUTION

NSPI proposes to align rates for electricity, maintenance and capital services with their costs. The capital and depreciation costs of LED fixtures are proposed to be assigned directly using an incremental cost approach and placed Below-the-Line. Consistent with the incremental cost approach to the pricing of LED services, the capital cost allowance (CCA) benefit associated with this investment is accounted for in the fixture pricing formulas.

NSPI is also proposing that the sacrificed asset costs associated with early retirements of non-LED fixtures, due to the LED deployment, be treated as a BTL item. These costs would be recouped through a conversion fee and applied to all full service non-LED streetlight customers at the time of their conversion.

4.1 Ratemaking Treatment of Proposed Changes in COSS

The cost determination process in the COSS for the unmetered services, other than those of LED capital services, is proposed to remain as is, with the exception for the treatment of non-LED fixture depreciation costs. The budgeted streetlight depreciation costs, available from NSPI's financial information systems, are proposed to be used for costing purposes of the non-LED fixtures. To make the relationship between costs of streetlight fixtures and their pricing transparent, the distribution-related capital costs of interest, taxes, and net earnings allocated to the unmetered class were split into two categories: non-streetlight fixture related costs and streetlight fixture related costs.

The capital costs of LED fixtures and the sacrifice asset costs associated with early retirements of non-LED fixtures are proposed to be treated as a BTL item, in a similar fashion to how BTL electric rate classes and Miscellaneous Revenues are accounted for. The depreciation costs of LED fixtures are proposed to be determined by applying a streetlight asset depreciation rate to the LED gross plant value. The other capital costs and taxes are determined by applying a tax adjusted weighted average cost of capital (WACC) to the LED net plant value. This approach is similar to the one used for the Open Access Transmission Tariff (OATT) and Transformer Ownership Credit calculations, except for the exclusion of the "grants in lieu of taxes' which are not incremental costs to LED streetlights. The sacrificed asset costs are proposed to be levelized and recouped through a conversion fee at the time of the mandated LED deployment. The LED fixture-related assets and expenses are treated in COSS in the same way as the assets and expenses of the BTL electric rate classes.

NSPI is not proposing any revisions to the cost allocators of electric service to the unmetered class.

Given that the LED streetlight related costs lack historical precedent and will not be recurring at the same level over a long period of asset life, its exclusion from the COSS-based costing process is appropriate and aligns with the overall purposes and intents of the COSS.

4.2 Ratemaking Treatment of Proposed Changes in Unmetered Rates

The proposed ratemaking approach is concerned with changes to the allocation of revenue responsibilities between electric service, as priced using Miscellaneous Lighting and Small Loads Rates, and capital services associated with both LED and non-LED investments, as priced using the marginal cost of capital substitution formula. The streetlight maintenance revenue is not affected, because it is proposed to remain as is for non-LED streetlight services. While fixture maintenance costs associated with LED streetlights may occur in the future, this component of the rate has not been set for 2012 pricing purposes.

NSPI does not propose any changes to the structure of the lighting and miscellaneous small load rates. Any changes to the unmetered electric service rates are attributable solely to the changes in revenue responsibilities of the LED streetlight service category.

4.3 LED Conversion Charge

NSPI proposes that an LED conversion charge be introduced to ensure the recovery of capital costs associated with early retired non-LED fixtures, due to the mandated LED deployment. The charge would apply to full service streetlight customers at the time of their conversion to LED streetlights, regardless of whether the customer would choose to continue to purchase full services from NSPI after the conversion. NSPI is proposing that Streetlight customers have a choice of a lump sum payment or a levelized monthly conversion fee, applicable over a five year period. The LED Conversion fee revenue is proposed to be treated as a Below-the-Line category.

5.0 STREET / CROSSWALK LIGHTING STUDY

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

In conducting this 2012 update (compared to the last update from 2006 Street / Crosswalk Lighting Study), 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 – Conversion Fee – Levelized Calculation
- Schedule 10A – Calculation of Conversion Fee (Per Fixture)
- Schedule 11 – Updated Street and Crosswalk Lighting Rates by Cost Component and Total Revenue based on forecast Inventory levels

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

The lighting units used for the purpose of 2012 test year rate calculation were forecasted using actual inventory levels as of March 2011, 2012 forecast of capital spend on non-LED and LED units, and 2012 forecast of unmetered electric load. 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 stepwise changes in the counts of many of the non-LED fixtures are anticipated as a result of their replacement with LED fixtures in 2012.

The projected total average non-LED units are 130,363. They are made up of 13,172 full charge lights, 987 “power and energy” and maintenance charge lights, and 116,204 “power and energy” only lights.

The projected total average LED units in 2012 are 13,133. They are made up of 11,559 full charge lights, and 1,573 “power and energy” only lights. There is no LED rate category proposed for the combined energy and maintenance services. The High Pressure (Intensity) Sodium lights are forecasted to account for the majority of the lights (73%) on NSPI’s system in 2012. This will change, however, in the next few years as LED deployment will come to displace most of the non-LED technology.

5.2 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 then used to determine the weighted total (column F) number of lights maintained. Current streetlight operating expenses were then used to determine annual and monthly maintenance costs by fixture type. The operating expenses used in this review are based on forecasted streetlight expenses from the Customer Operations area for 2012C including a share of corporate overhead and pension costs. This amount of $6.5 million is identified in the 2012C COSS in Exhibit 6A. The results, using the forecast weighted number of streetlights and the forecasted operating expenses for streetlights, 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.

5.3 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 methodology 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 Streetlighting Assets of $46.7M forecast for 2012 and the current material costs of each type of fixture, along with the forecast average number of fixtures for 2012, 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 $180.01 per fixture. Material cost information for incandescent and fluorescent lighting was not available and therefore an estimated escalation factor of 125% was applied to the Unit Costs from 1977. This schedule includes a sample material cost breakdown of 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

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. With over 120,000 fixtures scheduled to be replaced in five years, it is assumed NSPI will install about 24,000 fixtures per year, working its way area by area, and therefore economizing on labour and transportation costs. The LED installation cost is estimated to be $100 per fixture.

5.4 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 2012 is 5.33%. The tax-adjusted WACC for non-LED is 10.71% and LED is 9.62%. 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. The proposed methods of calculating the non-depreciation portion of the capital differ from the method used under the current methodology.

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 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, NSPI arrives at the preliminary revenue amount. This figure, being predicated on 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.

5.5 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; pretax 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 10.71% and 9.62% for non-LED and LED streetlights, respectively.

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

5.6 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. 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, NSPI has provided a detailed listing of all material costs obtained from the material inventory control system.

5.7 Schedule 8 - Lamp Life Analysis

Average Rated Life Spans of each lamp type, as provided in the Canadian Electrical Association's Lighting Reference Guide[3], 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, were then determined. The results of this analysis were 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] Product Knowledge – Lighting Reference Guide, Canadian Electrical Association, April 1992, originally printed by Ontario Hydro (4th Edition) 1991.

5.8 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 2012, being $17.7 million, is multiplied by the CCA rate. For LED streetlight purposes, the rate is 8%[4]. Note that in the first year, only half of the CCA rate can be claimed. For 2012, this results in tax savings of $0.219 million.

5.9 Schedule 10 – Conversion Fee – Levelized Calculation

Schedule 10 illustrates the levelized calculation of sacrificed asset life costs associated with early non-LED fixture retirements. This is calculated by reducing the year end (YE) net plant value by the proposed annual conversion rate of streetlight fixtures. The displaced net plant value of non-LED fixtures is then levelized over a 5 year period using the pre-tax WACC of 7.97%. This results in total levelized costs of $28.9 million (this is higher than the initial net plant value due to financing costs). Averaging this levelized amount, over a 5 year period, results in an average annual conversion cost of $5.8 million.

5.10 Schedule 10A – Calculation of Conversion Fee (Per Fixture)

Schedule 10A illustrates the transition of non-LED fixtures to LED fixtures by type, as well as provides details around the calculation of respective conversion fees. The conversion fee is calculated by applying the relative share of non-LED fixtures of their total capital-related annual revenue to the net plant value of retired fixtures. The allocated amounts to the non-LED fixture types are then aggregated by their LED counterparts. Dividing the stranded asset amount by the number of LED fixtures results in a conversion fee rate by fixture type that is proposed to be applied to LED customers,.

[4] Determined by Canada Revenue Agency

NSPI is proposing that collection of these funds be obtained over a 5 year period or through a lump sum payment, by choice of the customer. Both payment schedules are illustrated by fixture type in Schedule 10A. There is also a disposal cost associated with the mandated LED deployment. These costs are currently unknown, however will be included in the conversion fee charge at the time of the compliance filing.

5.11 Schedule 11 - New Street and Crosswalk Lighting Rates by Cost Component

Once the analysis of all costs components is complete, they 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 11 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 2012 and the percentage increase/decrease from the current approved rates for 2012. This results in total Street and Crosswalk Lighting Revenue for 2012 of $23.8 million

6.0 CONCLUSION

To ensure that the streetlight ratemaking methodology continues to meet the needs of a new operating environment typified by a large-scale conversion to the LED technology, NSPI proposes changes to the method of allocation of revenue responsibilities among three types of services: electric service, streetlight maintenance, and streetlight fixture capital. The present cost cross-subsidy between electric and streetlight fixture capital services is not sustainable.

A large-scale deployment of new LED technology is expected to take 5 years to complete. The static cost environment of streetlight services, we have known thus far, will change. The predictable and recurring capital related costs of the pre-LED world will be replaced with rapidly expanding capital expenditures. The COSS-based ratemaking approach will no longer be appropriate in pricing of the LED capital-related services. NSPI proposes to place the LED capital-related costs below-the-line to form a category of its own. This will provide a more transparent ratemaking treatment of this service.

APPENDIX A

STREET AND CROSSWALK LIGHTING STUDY

STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of FEBRUARY 2011

		MARCH 2011 (Quantity)				2012 FORECAST bfr LED Conversion (YA 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	28	0	7	35	28
002	Incandescent > 300 Watts	2	0	0	2	2	0	0	2	2
		29	0	7	36	30	0	7	37	30
100	Mercury Vapour 100 Watts	272	0	0	272	281	0	0	281	255
101/201/301	Mercury Vapour 125 Watts	11,222	7	11	11,240	11,577	7	11	11,596	10,511
102/202/302	Mercury Vapour 175 Watts	2,684	21	157	2,862	2,769	22	162	2,953	2,514
103/203/303	Mercury Vapour 250 Watts	1,033	35	54	1,122	1,066	36	56	1,158	968
104/204/304	Mercury Vapour 400 Watts	1,413	9	15	1,437	1,458	9	15	1,482	1,323
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	89	23	7	119	89
107	Mercury Vapour 250 Watt Cont. Oper.	3	0	0	3	3	0	0	3	3
		16,724	94	245	17,063	17,253	97	253	17,603	15,673
110	Fluorescent 2x24" 70 Watts	897	0	0	897	925	0	0	925	925
111	Fluorescent 2x48" 220 Watts	114	0	0	114	118	0	0	118	118
112	Fluorescent 2x72" 300 Watts	67	0	0	67	69	0	0	69	69
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	27	0	32	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	78	78	0
		1,101	30	78	1,209	1,136	31	80	1,247	1,136
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	18	18	0
119	Fluorescent Crosswalk Cont. 4x48"	0	0	23	23	0	0	24	24	0
120	Fluorescent Crosswalk Cont. 2x96"	0	0	30	30	0	0	31	31	0
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21	0	0	22	22	0
		0	0	92	92	0	0	95	95	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	26	26	0
315	Fluorescent Crosswalk 1x72"	0	0	0	0	0	0	0	0	0
		0	0	33	33	0	0	34	34	0
121/221/321	High Pressure Sodium 250 Watts	5,550	171	1,699	7,420	5,726	176	1,753	7,655	5,198
122/326	High Pressure Sodium 400 Watts	3,664	0	89	3,753	3,780	0	92	3,872	3,432
123/222/322	High Pressure Sodium 70 Watts	40,531	258	6,324	47,113	41,814	266	6,524	48,604	37,962
124/223/323	High Pressure Sodium 100 Watts	47,219	135	2,584	49,938	48,714	139	2,666	51,519	44,225
125/224/324	High Pressure Sodium 150 Watts	5,730	230	1,163	7,123	5,911	237	1,200	7,348	5,367
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	16	16	0	0	17	17	0
329	High Pressure Sodium 1500 Watts	0	0	1	1	0	0	1	1	0
		102,709	794	11,879	115,382	105,960	819	12,255	119,034	96,199
130	Low Pressure Sodium 135 Watts	58	0	0	58	60	0	0	60	54
131/231/331	Low Pressure Sodium 180 Watts	806	39	37	882	832	40	38	910	755
132	Low Pressure Sodium 90 Watts	0	0	0	0	0	0	0	0	0
		864	39	37	940	891	40	38	970	809
140/342	Metallic Arc 400 Watts	1,315	0	159	1,474	1,357	0	164	1,521	1,232
141/341	Metallic Arc 1000 Watts	981	0	22	1,003	1,012	0	23	1,035	1,012
142/343	Metallic Arc 250 Watts	109	0	84	193	112	0	87	199	102
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	116	116	0
345	Metallic Arc 150 Watts	0	0	20	20	0	0	21	21	0
346	Metallic Arc 100 Watts	0	0	0	0	0	0	0	0	0
		2,416	0	397	2,813	2,492	0	410	2,902	2,356
532/538	LED 44 Watts	0	0	96	96	0	0	99	99	0
539	LED 110 Watts	0	0	104	104	0	0	107	107	
533	LED 66 Watts	0	0	69	69	0	0	71	71	0
534	LED 88 Watts	0	0	291	291	0	0	300	300	0
540	LED 65 Watts	0	0	305	305	0	0	315	315	0
541	LED 55 Watts	0	0	198	198	0	0	204	204	0
542	LED 83 Watts	0	0	82	82	0	0	85	85	0
543	LED 48 Watts	0	0	72	72	0	0	74	74	
544	LED 72 Watts	0	0	308	308	0	0	318	318	
	Total	0	0	1,525	1,525	0	0	1,573	1,573	0
	Sat-48	0	0	0	0	0	0	0	0	5205
	Sat-72	0	0	0	0	0	0	0	0	4489
	Sat-96	0	0	0	0	0	0	0	0	1865
		0	0	0	0	0	0	0	0	11559
	Total	**123,843**	**957**	**14,293**	**139,093**	**127,763**	**987**	**14,745**	**143,496**	**127,763**

SCHEDULE 2

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

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Code	Lamp Type	Service Life (Years)	Maintenance Weighting Factors	# of Full Chg & Eng.+Maint. Fixtures	Weighting Total	Cost Per Year	Cost Per Month
A	Mercury Vapour	6.000	1.0000	5,282	5,282	$51.91	$4.33
B	Mercury Vapour - 125W	4.500	1.3333	10,518	14,024	$69.22	$5.77
C	Fluorescent	3.000	2.0000	1,167	2,334	$103.83	$8.65
D	High Pressure Sodium (Note1)	6.000	1.0000	97,034	97,034	$51.91	$4.33
E	Metallic Arc 100W, 150W & 250W	2.500	2.4000	112	270	$124.59	$10.38
F	Metallic Arc 400W	3.750	1.6000	1,232	1,971	$83.06	$6.92
G	Metallic Arc 1000W	2.500	2.4000	1,012	2,429	$124.59	$10.38
H	Low Pressure Sodium	2.000	3.0000	849	2,548	$155.74	$12.98
I	LED	20.000	0.3000	0	0	$15.57	$1.30
				117,206	125,891		

Street Lighting Maint. Expenses
(from 2012 COSS, Exhibit 6A) **$6,535,546**

Annual Cost of High Pressure Sodium
($6,535,546.23 / 125891.317695583 weighted fixtures) **$51.91**

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

STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

	Total
Gross Plant Value (including installation costs) less Retirements of Non-LED Street Lighting Equipment, 2012 Average	**$46,669,416**

Assumed Growth Factor in 2012

Description	Unit Cost Mar/1977	Unit Cost June 2007	Historical Mar-11 Fixtures	Average # of Fixtures bfr LED	Average # of Fixtures aft LED	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	27	28	28	$1,788	
Incandescent > 300 Watts	$63.62	$79.53	2	2	2	$164	
Mercury Vapour 100 Watts	$76.55	$229.55	272	281	255	$58,479	
Mercury Vapour 125 Watts	$77.16	$204.78	11,222	11,577	10,511	$2,152,405	
Mercury Vapour 175 Watts	$85.30	$201.27	2,684	2,769	2,514	$505,973	
Mercury Vapour 250 Watts	$87.24	$291.38	1,033	1,066	968	$281,913	
Mercury Vapour 400 Watts	$107.82	$301.45	1,413	1,458	1,323	$398,951	
Mercury Vapour 700 Watts	$485.12	$449.78	11	11	11	$5,104	
Mercury Vapour 1000 Watts	$492.29	$579.25	86	89	89	$51,393	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$291.38	3	3	3	$902	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	897	925	925	$123,123	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	114	118	118	$19,392	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	69	69	$15,442	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	15	15	$5,682	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	5	5	$1,032	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	1	1	1	$156	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	2	2	$487	
High Pressure Sodium 70 Watts	***N/A***	$207.51	40,531	41,814	37,962	$7,877,494	
High Pressure Sodium 100 Watts	***N/A***	$210.65	47,234	48,729	44,240	$9,319,017	
High Pressure Sodium 150 Watts	***N/A***	$232.66	5,730	5,911	5,367	$1,248,669	
High Pressure Sodium 250 Watts	$156.49	$231.67	5,550	5,726	5,198	$1,204,298	
High Pressure Sodium 400 Watts	$173.73	$246.21	3,664	3,780	3,432	$844,944	
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	58	60	54	$30,124	
Low Pressure Sodium 180 Watts	$226.10	$880.14	806	832	755	$664,429	
Metallic Additive 250 Watts	***N/A***	$298.33	113	117	106	$31,574	
Metallic Additive 400 Watts	$358.84	$305.76	1,315	1,357	1,232	$376,588	
Metallic Additive 1000 Watts	$560.49	$526.16	981	1,012	1,012	$532,497	
Metallic Additive 100 Watts	***N/A***		7	7	7	$0	
			123,843	127,763	116,204		**25,752,020**
							$20,917,395
							$180.01
Total # of light types being displaced by LED			121,632	125,482	113,923		
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**

STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

	Non Led	Led
Depreciation Rate for 2012	5.33%	5.33%
# of Years	18.76	18.76
Tax Adjusted Weighted Average Cost of Capital	10.71%	9.62%
Pre-tax WACC	7.97%	7.97%
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 2012	0.00%	0.00%
# of Years	N/A	N/A

		Revenue Correction factors	
simulated at current meth.		$8,603,338	1,314,036.94
total cost per COSS		$4,194,480	$1,314,415
factor non-LED		**0.4875**	**1.0003**

	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	2012 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Incandescent < 300 Watts	$64.20	180.01	$244.21	$18.86	$26.15	$0.00	$45.02	0.488	$21.95	$1.83	28	525.45	728.52		1,253.98	611.36
Incandescent > 300 Watts	79.53	180.01	259.53	$20.05	$27.80	$0.00	47.84	0.488	$23.33	1.94	2	41.36	57.35		98.72	48.13
Mercury Vapour 100 Watts	229.55	180.01	409.55	$31.64	$43.86	$0.00	75.50	0.488	$36.81	3.07	255	8,059.72	11,174.58		19,234.31	9,377.51
Mercury Vapour 125 Watts	204.78	180.01	384.79	$29.72	$41.21	$0.00	70.93	0.488	$34.58	2.88	10,511	312,415.38	433,155.42		745,570.80	363,496.36
Mercury Vapour 175 Watts	201.27	180.01	381.28	$29.45	$40.83	$0.00	70.29	0.488	$34.27	2.86	2,514	74,039.68	102,654.00		176,693.69	86,145.42
Mercury Vapour 250 Watts	291.38	180.01	471.38	$36.41	$50.48	$0.00	86.90	0.488	$42.37	3.53	968	35,230.05	48,845.51		84,075.57	40,990.29
Mercury Vapour 400 Watts	301.45	180.01	481.46	$37.19	$51.56	$0.00	88.75	0.488	$43.27	3.61	1,323	49,219.75	68,241.84		117,461.60	57,267.35
Mercury Vapour 700 Watts	449.78	180.01	629.79	$48.65	$67.45	$0.00	116.10	0.488	$56.60	4.72	11	552.08	765.44		1,317.51	642.34
Mercury Vapour 1000 Watts	579.25	180.01	759.26	$58.65	$81.32	$0.00	139.97	0.488	$68.24	5.69	89	5,203.56	7,214.59		12,418.14	6,054.35
Mercury Vapour 250 Watt Cont. Oper.	291.38	180.01	471.38	$36.41	$50.48	$0.00	86.90	0.488	$42.37	3.53	3	112.70	156.25		268.94	131.12
Fluorescent 2x24" 70 Watts	133.05	180.01	313.06	$24.18	$33.53	$0.00	57.71	0.488	$28.14	2.34	925	22,378.28	31,026.88		53,405.15	26,037.20
Fluorescent 2x48" 220 Watts	164.89	180.01	344.89	$26.64	$36.94	$0.00	63.58	0.488	$31.00	2.58	118	3,133.30	4,344.24		7,477.54	3,645.61
Fluorescent 2x72" 300 Watts	223.40	180.01	403.41	$31.16	$43.20	$0.00	74.37	0.488	$36.26	3.02	69	2,153.92	2,986.35		5,140.27	2,506.09
Fluorescent 4x72" 600 Watts	367.15	180.01	547.16	$42.27	$58.60	$0.00	100.87	0.488	$49.18	4.10	15	654.06	906.83		1,560.88	761.00
Fluorescent 1x96" 110 Watts	200.00	180.01	380.01	$29.35	$40.70	$0.00	70.05	0.488	$34.15	2.85	5	151.42	209.93		361.35	176.17
Fluorescent 1x72" 150 Watts	151.53	180.01	331.53	$25.61	$35.51	$0.00	61.12	0.488	$29.80	2.48	1	26.42	36.63		63.05	30.74
Fluorescent 4x48" 440 Watts	236.14	180.01	416.14	$32.15	$44.57	$0.00	76.71	0.488	$37.40	3.12	2	66.33	91.96		158.29	77.17
High Pressure Sodium 70 Watts	207.51	180.01	387.52	$29.93	$41.50	$0.00	71.44	0.488	$34.83	2.90	37,962	1,136,363.99	1,575,537.76		2,711,901.76	1,322,163.39
High Pressure Sodium 100 Watts	210.65	180.01	390.65	$30.18	$41.84	$0.00	72.02	0.488	$35.11	2.93	44,240	1,335,013.03	1,850,959.25		3,185,972.28	1,553,292.23
High Pressure Sodium 150 Watts	232.66	180.01	412.67	$31.88	$44.20	$0.00	76.07	0.488	$37.09	3.09	5,367	171,079.89	237,197.61		408,277.50	199,052.04
High Pressure Sodium 250 Watts	231.67	180.01	411.68	$31.80	$44.09	$0.00	75.89	0.488	$37.00	3.08	5,198	165,308.16	229,195.27		394,503.43	192,336.61
High Pressure Sodium 400 Watts	246.21	180.01	426.22	$32.92	$45.65	$0.00	78.57	0.488	$38.31	3.19	3,432	112,987.05	156,653.47		269,640.51	131,460.81
High Pressure Sodium 1000 Watts	615.53	180.01	795.54	$61.45	$85.20	$0.00	146.65	0.488	$71.50	5.96	-	-	-		-	-
Low Pressure Sodium 90 Watts	554.53	180.01	734.54	$56.74	$78.67	$0.00	135.41	0.488	$66.02	5.50	-	-	-		-	-
Low Pressure Sodium 135 Watts	554.53	180.01	734.54	$56.74	$78.67	$0.00	135.41	0.488	$66.02	5.50	54	3,082.35	4,273.59		7,355.94	3,586.32
Low Pressure Sodium 180 Watts	880.14	180.01	1,060.15	$81.89	$113.54	$0.00	195.43	0.488	$95.28	7.94	755	61,821.66	85,714.04		147,535.70	71,929.71
Metallic Arc 250 Watts	298.33	180.01	478.33	$36.95	$51.23	$0.00	88.18	0.488	$42.99	3.58	106	3,910.66	5,422.02		9,332.67	4,550.06
Metallic Arc 400 Watts	305.76	180.01	485.77	$37.52	$52.03	$0.00	89.55	0.488	$43.66	3.64	1,232	46,215.99	64,077.21		110,293.20	53,772.46
Metallic Arc 1000 Watts	$526.16	180.01	$706.16	$54.55	$75.63	$0.00	$130.18	0.488	$63.47	$5.29	1,012	55,205.88	76,541.45		131,747.32	64,232.23
Metallic Additive 100 Watts	$0.00	180.01	$180.01	$13.90	$19.28	$0.00	$33.18	0.488	$16.18	$1.35	7	91.16	126.40		217.56	106.07
Total											**116,204**	**$3,605,043**	**$4,998,294**		**$8,603,338**	**$4,194,480**

LED Costs Before Levelization

	Material Cost January 2010	Labour Cost	Total	Before Correction Factor: Depreciation Expense	Cost of Capital	CCA Benefit	Total Cost	Correction Factor	Results: Total Annual Cost	Monthly Cost	2012 Forecast: # of fixtures	depreciation expense	cost of capital	CCA	revenue	Total Annual scaled
Sat-48	552.27	100.00	$652.27	50.39	$62.75	-$18.97	$94.17	1.0003	$94.20	$7.85	5,205	262,280.22	326,634.83	(98,726.00)	490,189.06	490,330.26
Sat-72	729.28	100.00	$829.28	64.06	$79.78	-$18.97	$124.87	1.0003	$124.91	$10.41	4,489	287,554.15	358,110.11	(85,135.72)	560,528.54	560,690.01
Sat-96	823.38	100.00	$923.38	71.33	$88.83	-$18.97	$141.19	1.0003	$141.23	$11.77	1,865	133,025.15	165,664.98	(35,370.78)	263,319.35	263,395.20
Total											**11,559**	**682,859.52**	**850,409.92**	**(219,232.50)**	**1,314,036.94**	**1,314,415.47**

Schedule 5

STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Rate by Components For 2012 Street Light Rates

				Non-LED		LED
a) Weighted Average Cost of Capital - Pretax				**Non-LED**		**LED**
	Proportion	Cost	Extended		Extended	
ST Debt	9.2%	2.3%	0.2%	0.21%	0.21%	0.21%
LT Debt	49.5%	8.0%	3.9%	3.94%	3.94%	3.94%
Preferred	3.7%	5.9%	0.2%	0.22%	0.22%	0.22%
Common	37.5%	9.6%	3.6%	3.60%	3.60%	3.60%
	100.0%		8.0%		7.97%	
WACC - pretax cost				7.97%		7.97%
b) Additional income tax for common equity						
Extended equity cost			3.60%		3.60%	
Effective tax rate (excluding surtax)			31.0%		31.0%	
Income tax			1.62%		1.62%	
WACC - equity tax cost				1.62%		1.62%
c) Large Corporations Tax						
Provincial capital tax (2011)			0.025%		0.025%	
Federal capital tax (2011)			0.000%		0.000%	
Ave. NBV - Street Lighting			$21.981		$8.840	
Ave. NBV - Assigned GP Plt.			1.731		0.696	
Ave. Deferred Chgs & W/C			3.145		1.265	
NPV - Total Street Lighting			$26.857		$10.801	
Provincial capital tax			$0.007		$0.003	
Federal capital tax			$0.000		$0.000	
Total			$0.007		$0.003	
Percentage of NBV			0.03%		0.03%	
WACC - Large Corporations Tax				0.03%		0.03%
d) Grants in Lieu of Property Tax						
Total 2011 Forecasted Expense			$36.400		N/A	
St. Lgts. % of Total Electric Plant			0.80%		N/A	
St. Lgts. Allocated Amount			$0.292		N/A	
Percentage of NBV			1.09%		N/A	
WACC - Grants in Lieu of Property Tax				1.09%		N/A
Total WACC - Interest / Carrying Cost				**10.71%**		**9.62%**

SCHEDULE 5A

STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components
For 2012 Street Light Rates

Capital Cost Expenses (Net Plant Value)
For 2012 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	LED	Non LED	LED
Gross Plant Value (YA)			$46,669	$17,680
Net Plant Value (YA)			$21,981	$8,840
a) Weighted Average Cost of Capital - Pretax				
ST Debt	0.21%	0.21%		$19.0
LT Debt	3.94%	3.94%		$348.6
Subtotal			*728*	*$367.5*
Preferred	0.22%	0.22%	$48.5	$19.1
Common	3.60%	3.60%	$767.7	$318.2
WACC - pretax cost	7.97%	7.97%	$1,543.8	$704.9
b) Additional income tax for common equity				
WACC - equity tax cost	1.62%	1.62%		$143.2
c) Large Corporations Tax				
WACC - Large Corporations Tax	0.03%	0.03%		$2.7
Subtotal			*$248.0*	*$145.9*
d) Grants in Lieu of Property Tax				
WACC - Grants in Lieu of Property Tax	1.09%		$213.3	$0.0
Subtotal Financing Expense	**10.71%**	**9.62%**	**$2,005.1**	**$850.8**
Depreciation Expense			**$2,189.4**	**$682.9**
CCA			**$0.0**	**-$219.2**
TOTAL CAPITAL COST EXPENSE			**$4,194.5**	**$1,314.4**

SCHEDULE 6

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

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2010	Location	AVG COST 2011
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		
0057350350	LUMINAIRE LPS 135W	463.38		

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2010	Location	AVG COST 2011
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		
0057404050	FLOODLIGHT M V 400 W	281.17	XX	
0057404600	FLOODLIGHT 400W HPS CWI	194.95	C11A	

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
March 2011

ITEM	DESCRIPTION	AVG COST 2010	Location	AVG COST 2011
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		
0057608722	STARTER FOR HPS 100V	36.35		
0057608730	STARTER FOR SODIUM	48.16		
0065734220	CABLE CU ST-LITE 2C #12	1.03		

SCHEDULE 8

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
CCA Schedule
Millions of dollars

Schedule 9

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	
	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	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	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%	-	16,972,838	15,615,011	14,365,810	13,216,546	12,159,222	11,186,484	10,291,565	9,468,240	8,710,781	8,013,919	7,372,805	6,782,981	6,240,342	5,741,115	5,281,826	4,859,280	4,470,537	4,112,894	3,783,863	3,481,154	3,202,661	2,946,448	2,710,733	2,493,874	2,294,364	2,110,815	**187,886,108**
	-	**16,972,838**	**15,615,011**	**14,365,810**	**13,216,546**	**12,159,222**	**11,186,484**	**10,291,565**	**9,468,240**	**8,710,781**	**8,013,919**	**7,372,805**	**6,782,981**	**6,240,342**	**5,741,115**	**5,281,826**	**4,859,280**	**4,470,537**	**4,112,894**	**3,783,863**	**3,481,154**	**3,202,661**	**2,946,448**	**2,710,733**	**2,493,874**	**2,294,364**	**2,110,815**	**187,886,108**
Additions																												
8%	17,680,040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	17,680,040	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**17,680,040**
CCA																												
8%	707,202	1,357,827	1,249,201	1,149,265	1,057,324	972,738	894,919	823,325	757,459	696,862	641,113	589,824	542,638	499,227	459,289	422,546	388,742	357,643	329,032	302,709	278,492	256,213	235,716	216,859	199,510	183,549	168,865	**15,738,090**
	707,202	**1,357,827**	**1,249,201**	**1,149,265**	**1,057,324**	**972,738**	**894,919**	**823,325**	**757,459**	**696,862**	**641,113**	**589,824**	**542,638**	**499,227**	**459,289**	**422,546**	**388,742**	**357,643**	**329,032**	**302,709**	**278,492**	**256,213**	**235,716**	**216,859**	**199,510**	**183,549**	**168,865**	**15,738,090**
Ending UCC																												
8%	16,972,838	15,615,011	14,365,810	13,216,546	12,159,222	11,186,484	10,291,565	9,468,240	8,710,781	8,013,919	7,372,805	6,782,981	6,240,342	5,741,115	5,281,826	4,859,280	4,470,537	4,112,894	3,783,863	3,481,154	3,202,661	2,946,448	2,710,733	2,493,874	2,294,364	2,110,815	1,941,950	**189,828,058**
	16,972,838	**15,615,011**	**14,365,810**	**13,216,546**	**12,159,222**	**11,186,484**	**10,291,565**	**9,468,240**	**8,710,781**	**8,013,919**	**7,372,805**	**6,782,981**	**6,240,342**	**5,741,115**	**5,281,826**	**4,859,280**	**4,470,537**	**4,112,894**	**3,783,863**	**3,481,154**	**3,202,661**	**2,946,448**	**2,710,733**	**2,493,874**	**2,294,364**	**2,110,815**	**1,941,950**	**189,828,058**
Tax Rate:	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	31.0%	**8**
Tax Savings from CCA :	219,232	420,926	387,252	356,272	327,770	301,549	277,425	255,231	234,812	216,027	198,745	182,846	168,218	154,760	142,380	130,989	120,510	110,869	102,000	93,840	86,333	79,426	73,072	67,226	61,848	56,900	52,348	**4,878,808**

Schedule 10

Conversion Fee - Levelized Calculation

WACC pretax 7.97%

Levelized Costs of Stranded Net Plant Value

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Cumulative
LED Conversions YE		23,119	24,628	24,628	24,628	24,628						
Fixture Inventory YE	121,632	98,513	73,885	49,257	24,628	0						
Annual Conversion Rate		19%	20%	20%	20%	20%	100%					
		19%	39%	60%	80%	100%						
Net Plant Value YE[1]	$23.10	$18.71	$14.03	$9.35	$4.68	$0.00						
Net Plant Value of displaced non-LED (YE)		($4.39)	($4.68)	($4.68)	($4.68)	($4.68)						($23.10)
Net Plant Value of displaced non-LED (YA)		($2.20)	($4.53)	($4.68)	($4.68)	($4.68)	($2.34)					($23.10)
Annual Levelized Cost Y1		($0.55)	($1.10)	($1.10)	($1.10)	($1.10)	($0.55)					($5.49)
Annual Levelized Cost Y2			($0.59)	($1.17)	($1.17)	($1.17)	($1.17)	($0.59)				($5.85)
Annual Levelized Cost Y3				($0.59)	($1.17)	($1.17)	($1.17)	($1.17)	($0.59)			($5.85)
Annual Levelized Cost Y4					($0.59)	($1.17)	($1.17)	($1.17)	($1.17)	($0.59)		($5.85)
Annual Levelized Cost Y5						($0.59)	($1.17)	($1.17)	($1.17)	($1.17)	($0.59)	($5.85)
Total Levelized Costs												($28.90)
Average Costs over 5 yr period												($5.78)

Schedule 10A

Calculation of Conversion Fee (Per Fixture)

Type of Non LED Light	Capital Cost/Month	# of Fix (brf conv.)	Annual Revenue	Relative Share	Stranded Asset	Monthly LED conversion Fee (5 Years)	Lump Sum LED conversion Fee	Lump Sum LED conversion Fee (per fix.)	Type of LED Light
100W MV	$3.07	272	$10,009	0.23%	$13,257	$4.06	$52,974.14	$194.76	Sat-48-44W
125W MV	$2.88	11222	$387,983	8.89%	$513,873	$3.82	$2,053,369.93	$182.98	Sat-48-55W
175W MV	$2.85	2684	$91,948	2.11%	$121,783	$3.78	$486,628.95	$181.31	Sat-48-87W
250W MV	$3.53	1033	$43,754	1.00%	$57,951	$4.68	$231,566.54	$224.17	Sat-96-88W
400W MV	$3.61	1413	$61,129	1.40%	$80,964	$4.77	$323,522.49	$228.96	Sat-96-173W
			$0						
250W HPS	$3.08	5550	$205,298	4.70%	$271,912	$4.08	$1,086,523.05	$195.77	Sat-96-110W
400W HPS	$3.19	3664	$140,321	3.21%	$185,852	$4.23	$742,639.60	$202.69	Sat-96-173W
70W HPS	$2.90	40531	$1,411,232	32.33%	$1,869,141	$3.84	$7,468,842.81	$184.27	Sat-48-44W
100W HPS	$2.93	47219	$1,657,409	37.97%	$2,195,196	$3.87	$8,771,717.20	$185.77	Sat-72-65W
150W HPS	$3.09	5730	$212,466	4.87%	$281,406	$4.09	$1,124,459.82	$196.24	Sat-96-88W
			$0						
135W LPS	$5.50	58	$3,829	0.09%	$5,071	$7.29	$20,262.28	$349.35	Sat-48-74W
180W LPS	$7.94	806	$76,792	1.76%	$101,709	$10.52	$406,416.63	$504.24	Sat-96-88W
			$0						
400W MAL	$3.64	1315	$57,399	1.32%	$76,023	$4.82	$303,779.45	$231.01	Sat-96-173W
250W MAL	$3.58	109	$4,685	0.11%	$6,205	$4.74	$24,794.87	$227.48	Sat-96-110W
150W MAL	$3.58	4	$172	0.00%	$228		$909.90	$227.48	Sat-96-88W
100W MAL	$3.58	7	$301	0.01%	$398	$4.74	$1,592.33	$227.48	Sat-48-55W
Total		**121,617**	**$4,364,728**	**100.00%**	**$5,780,970**		**$23,100,000**		

Transition of Non LED Fixtures to appropriate LED fixtures

	Capital Cost/Month	# of Fixtures	Stranded Asset	Monthly LED conversion Exit Fee (5 years)	Lump Sum LED conversion Fee	Lump Sum LED conversion Fee (per fix.)	Salvage Value[1]	Total Lump Sum LED Conversion Fee
LED Sat-48-44W	$5.59	40,803	$1,882,398	$3.84	$7,521,817	$184.34	N/A	$184.34
LED Sat-48-55W	$5.59	11,229	$514,272	$3.82	$2,054,962	$183.00	N/A	$183.00
LED Sat-48-74W	$5.59	58	$5,071	$7.29	$20,262	$349.35	N/A	$349.35
LED Sat-48-87W	$5.59	2,684	$121,783	$3.78	$486,629	$181.31	N/A	$181.31
LED Sat-72-65W	$7.10	47,219	$2,195,196	$3.87	$8,771,717	$185.77	N/A	$185.77
LED Sat-96-88W	$7.91	7,573	$441,294	$4.86	$1,763,353	$232.85	N/A	$232.85
LED Sat-96-110W	$7.91	5,659	$278,117	$4.10	$1,111,318	$196.38	N/A	$196.38
LED Sat-96-173W	$7.91	6,392	$342,839	$4.47	$1,369,942	$214.32	N/A	$214.32
Total		**121,617**	**$5,780,970**		**$23,100,000**			

1) At the time of filing, the salvage value was unknown. This will be made available at the time of the Compliance Filing

SCHEDULE 11

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2012

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2012 New Proposed Rates	2012 New Proposed Revenue	2011 Current Rates	Percent Change	2012 (YA) Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent < 300 Watts - Note 1	001	97	$12.79	4.33	$1.83	$18.95	$6,333	$20.18	-6.1%	28	($412)	0.291	8.106	
Incandescent > 300 Watts - Note 1	002	154	20.29	4.33	1.94	$26.56	658	$26.56	0.0%	2	0	0.462	0.953	
Incandescent < 300 Watts - Note 1	003	97	12.79	0.00	0.00	$12.79	1,108	$10.64	20.2%	7	186	0.291	2.101	
							8,099			37	(226)			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43	**5.68**	4.33	3.07	$13.07	39,968	$13.40	-2.4%	255	(990)	0.129	32.864	
Mercury Vapour 125 Watts	101	52	**6.85**	5.76824	2.88	$15.50	1,955,018	$15.05	3.0%	10,511	56,899	0.156	1,639.672	
Mercury Vapour 175 Watts	102	69	**9.08**	4.33	2.86	$16.26	490,564	$15.84	2.7%	2,514	12,674	0.207	520.373	
Mercury Vapour 250 Watts	103	97	12.79	4.33	3.53	$20.65	239,714	$20.18	2.3%	968	5,459	0.291	281.550	
Mercury Vapour 400 Watts	104	154	**20.29**	4.33	3.61	$28.22	448,204	$26.56	6.3%	1,323	26,457	0.462	611.429	
Mercury Vapour 700 Watts	105	260	34.28	4.33	4.72	$43.32	5,900	$40.20	7.8%	11	425	0.780	8.852	
Mercury Vapour 1000 Watts	106	363	47.85	4.33	5.69	$57.86	61,605	$53.19	8.8%	89	4,979	1.089	96.618	
Mercury Vapour 250 Watt Cont. Oper.	107	212	21.70	8.65	3.53	$33.88	1,258	$30.68	10.5%	3	119	0.291	0.901	0.901
Mercury Vapour 125 Watts	201	52	6.85	5.77	0.00	$12.62	1,093	$9.79	28.9%	7	245	0.156	1.127	
Mercury Vapour 175 Watts	202	69	9.08	4.33	0.00	$13.41	3,485	$10.63	26.1%	22	721	0.207	4.485	
Mercury Vapour 250 Watts	203	97	12.79	4.33	0.00	$17.12	7,416	$13.72	24.8%	36	1,472	0.291	10.507	
Mercury Vapour 400 Watts	204	154	20.29	4.33	0.00	$24.62	2,743	$19.96	23.3%	9	518	0.462	4.290	
Mercury Vapour 700 Watts	205	260	34.28	4.33	0.00	$38.61	0	$31.60	22.2%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363	47.85	4.33	0.00	$52.18	14,211	$42.90	21.6%	23	2,526	1.089	24.716	
Mercury Vapour 125 Watts	301	52	6.85	0.00	0.00	$6.85	933	$5.69	20.4%	11	158	0.156	1.770	
Mercury Vapour 175 Watts	302	69	9.08	0.00	0.00	$9.08	17,648	$7.55	20.2%	162	2,970	0.207	33.528	
Mercury Vapour 250 Watts	303	97	12.79	0.00	0.00	$12.79	8,550	$10.64	20.2%	56	1,438	0.291	16.211	
Mercury Vapour 400 Watts	304	154	20.29	0.00	0.00	$20.29	3,768	$16.88	20.2%	15	633	0.462	7.149	
Mercury Vapour 700 Watts	305	260	34.28	0.00	0.00	$34.28	424	$28.52	20.2%	1	71	0.780	0.805	
Mercury Vapour 1000 Watts	306	363	47.85	0.00	0.00	$47.85	4,147	$39.82	20.2%	7	696	1.089	7.864	
							3,306,649			16,023	117,470			
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30	**3.96**	8.65	2.34	$14.96	166,094	$13.74	8.8%	925	13,491	0.091	84.211	
Fluorescent 2x48" 220 Watts	111	85	11.21	8.65	2.58	$22.45	31,677	$20.20	11.1%	118	3,173	0.254	29.873	
Fluorescent 2x72" 300 Watts	112	116	**15.31**	8.65	3.02	$26.98	22,382	$24.41	10.5%	69	2,136	0.348	24.054	
Fluorescent 4x72" 600 Watts	113	222	**29.25**	8.65	4.10	$42.00	7,799	$37.95	10.7%	15	752	0.665	10.291	
Fluorescent 1x96" 110 Watts	114	47	**6.19**	8.65	2.85	$17.69	1,095	$16.50	7.2%	5	74	0.141	0.727	
Fluorescent 1x72" 150 Watts	115	60	7.91	8.65	2.48	$19.05	236	$17.28	10.2%	1	22	0.180	0.186	
Fluorescent 4x48" 440 Watts	116	166	**21.90**	8.65	3.12	$33.67	834	$30.07	12.0%	2	89	0.499	1.030	
							230,117			1,136	19,737			
Fluorescent 4x72" 600 Watts	213	222	29.25	8.65	0.00	$37.90	0	$30.48	24.3%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47	6.19	8.65	0.00	$14.84	4,777	$11.30	31.4%	27	1,141	0.141	3.782	
Fluorescent 1x72" 150 Watts	215	60	7.91	8.65	0.00	$16.56	615	$12.74	30.0%	3	142	0.180	0.557	
Fluorescent 4x48" 440 Watts	216	166	21.90	8.65	0.00	$30.55	0	$24.38	25.3%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49	**6.44**	8.65	0.00	$15.09	187	$11.51	31.1%	1	44	0.146	0.151	
Fluorescent 2x48" 220 Watts	218	85	11.21	8.65	0.00	$19.86	0	$15.47	28.4%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47	**6.19**	0.00	0.00	$6.19	153	$5.15	20.2%	2	26	0.140	0.289	
							5,733			33	1,353			

SCHEDULE 11

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2012

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2012 New Proposed Rates	2012 New Proposed Revenue	2011 Current Rates	Percent Change	2012 (YA) Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486	49.74	0.00	0.00	$49.74	616	$41.39	20.2%	1	103	0.665	0.686	0.686
Fluorescent 2x24" 70 Watts	118	66	6.75	0.00	0.00	$6.75	1,421	$5.61	20.3%	18	240	0.091	1.596	1.596
Fluorescent 4x48" 440 Watts	119	364	37.27	0.00	0.00	$37.27	10,612	$31.01	20.2%	24	1,782	0.499	11.840	11.840
Fluorescent 2x96"	120	254	26.01	0.00	0.00	$26.01	9,660	$21.64	20.2%	31	1,621	0.348	10.770	10.770
Fluorescent 4x96"	150	613	62.75	0.00	0.00	$62.75	16,314	$52.21	20.2%	22	2,739	0.840	18.198	18.198
							38,622			95	6,485			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30	3.96	0.00	0.00	$3.96	98	$3.30	20.1%	2	16	0.091	0.188	
Fluorescent 4x48" 440 Watts	311	166	21.90	0.00	0.00	$21.90	1,356	$18.23	20.1%	5	227	0.499	2.574	
Fluorescent 2x72" 300 Watts	312	116	15.31	0.00	0.00	$15.31	190	$12.74	20.2%	1	32	0.348	0.359	
Fluorescent 4x72" 600 Watts	313	222	29.25	0.00	0.00	$29.25	0	$24.33	20.2%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47	6.19	0.00	0.00	$6.19	1,916	$5.15	20.2%	26	322	0.142	3.662	
Fluorescent 1x72" 150 Watts	315	60	7.91	0.00	0.00	$7.91	0	$6.59	20.1%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280	36.92	0.00	0.00	$36.92	34,737	$30.72	20.2%	78	5,833	0.841	65.939	
							38,296			112	6,430			
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60	7.91	12.98	5.50	$26.39	17,203	$26.41	-0.1%	54	(12)	0.180	9.778	
Low Pressure Sodium 180 Watts	131	80	10.55	12.98	7.94	$31.47	285,074	$28.05	12.2%	755	30,995	0.240	181.179	
Low Pressure Sodium 90 Watts	132	45	5.92	12.98	5.50	$24.40	0	$24.75	-1.4%	0	0	0.135	0.000	
Low Pressure Sodium 180 Watts E&M	231	80	10.55	12.98	0.00	$23.53	11,360	$18.01	30.7%	40	2,665	0.240	9.656	
Low Pressure Sodium 180 Watts E/O	331	80	10.55	0.00	0.00	$10.55	4,832	$8.78	20.2%	38	811	0.240	9.161	
							318,470			888	34,459			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100	13.18	4.33	3.08	$20.59	1,284,350	$19.83	3.8%	5,198	47,386	0.300	1,559.468	
High Pressure Sodium 400 Watts	122	150	19.77	4.33	3.19	$27.29	1,123,770	$25.48	7.1%	3,432	74,631	0.450	1,544.295	
High Pressure Sodium 70 Watts	123	32	4.21	4.33	2.90	$11.44	5,210,774	$11.78	-2.9%	37,962	(155,867)	0.096	3,644.355	
High Pressure Sodium 100 Watts	124	45	5.92	4.33	2.93	$13.17	6,992,808	$13.10	0.5%	44,240	37,074	0.135	5,972.424	
High Pressure Sodium 150 Watts	125	65	8.57	4.33	3.09	$15.99	1,029,589	$15.35	4.2%	5,367	41,303	0.195	1,046.529	
HP Sodium 100 Watts - Cont. Oper.	126	99	10.11	8.65	2.93	$21.69	0	$19.67	10.3%	0	0	0.135	0.000	0.000
High Pressure Sodium 250 Watts	221	100	13.18	4.33	0.00	$17.51	37,060	$14.05	24.6%	176	7,315	0.300	52.924	
High Pressure Sodium 70 Watts	222	32	4.21	4.33	0.00	$8.54	27,265	$6.58	29.7%	266	6,250	0.096	25.552	
High Pressure Sodium 100 Watts	223	45	5.92	4.33	0.00	$10.25	17,124	$8.01	28.0%	139	3,742	0.135	18.802	
High Pressure Sodium 150 Watts	224	65	8.57	4.33	0.00	$12.90	36,720	$10.21	26.3%	237	7,650	0.195	46.270	
High Pressure Sodium 250 Watts	321	100	13.18	0.00	0.00	$13.18	277,219	$10.97	20.1%	1,753	46,467	0.300	525.833	
High Pressure Sodium 70 Watts	322	32	4.21	0.00	0.00	$4.21	329,601	$3.50	20.3%	6,524	55,629	0.096	626.320	
High Pressure Sodium 100 Watts	323	45	5.92	0.00	0.00	$5.92	189,378	$4.93	20.1%	2,666	31,754	0.135	359.882	
High Pressure Sodium 150 Watts	324	65	8.57	0.00	0.00	$8.57	123,389	$7.13	20.2%	1,200	20,740	0.195	233.963	
High Pressure Sodium 400 Watts	326	150	19.77	0.00	0.00	$19.77	21,783	$16.45	20.2%	92	3,657	0.450	41.318	
High Pressure Sodium 500 Watts	327	183	24.13	0.00	0.00	$24.13	896	$20.08	20.2%	3	150	0.550	1.702	
High Pressure Sodium 1000 Watts	328	363	47.86	0.00	0.00	$47.86	9,480	$39.83	20.2%	17	1,590	1.090	17.992	
High Pressure Sodium 1500 Watts	329	500	65.91	0.00	0.00	$65.91	816	$54.84	20.2%	1	137	1.090	1.125	
							16,712,021			109,273	229,471			

SCHEDULE 11

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2012

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2012 New Proposed Rates	2012 New Proposed Revenue	2011 Current Rates	Percent Change	2012 (YA) Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150	19.77	6.92	3.64	$30.33	448,274	$28.00	8.3%	1,232	34,409	0.450	554.243	
Metallic Arc 1000 Watts	141	360	47.46	10.38	5.29	$63.13	766,711	$56.51	11.7%	1,012	80,385	1.080	1,093.015	
Metallic Arc 250 Watts	142	100	13.18	10.38	3.58	$27.15	33,132	$24.90	9.0%	102	2,740	0.300	30.513	
Metallic Arc 150 Watts	143	67	8.82	10.38	3.58	$22.79	1,128	$21.27	7.1%	4	75	0.200	*0.825*	
Metallic Arc 100 Watts	144	50	6.59	10.38	3.58	$20.56	1,617	$19.41	5.9%	7	90	0.150	0.983	
Metallic Arc 1000 Watts	341	360	47.46	0	0	$47.46	12,926	$39.49	20.2%	23	2,171	1.080	24.512	
Metallic Arc 400 Watts	342	150	19.77	0	0	$19.77	38,915	$16.45	20.2%	164	6,533	0.450	73.815	
Metallic Arc 250 Watts	343	100	13.18	0	0	$13.18	13,706	$10.97	20.1%	87	2,297	0.300	25.998	
Metallic Arc 175 Watts	344	75	9.89	0	0	$9.89	13,713	$8.23	20.2%	116	2,308	0.225	25.998	
Metallic Arc 150 Watts	345	67	8.82	0	0	$8.82	2,184	$7.34	20.2%	21	366	0.200	4.127	
Metallic Arc 100 Watts	346	50	6.59	0	0	$6.59	0	$5.48	20.2%	0	0	0.150	0.000	
							1,332,306			2,766	131,374			
Light Emitting Diode - Traffic Lights														
Light Emitting Diode 4.6 Watts	530	3	0.40	0	0	$0.40	0	$0.27	49.1%		0		0.000	
Light Emitting Diode 7.5 Watts	531	5	0.66	0	0	$0.66	0	$0.44	48.7%		0		0.000	
							0							
Light Emitting Diode (Energy Only)														
Lighting Emitting Diode 44 Watts	532	15	1.98	0	0	$1.98	2,353	$1.63	21.5%	99	417	0.440	43.577	
Lighting Emitting Diode 66 Watts	533	22	2.90	0	0	$2.90	2,477	$2.41	20.2%	71	416	0.660	46.981	
Lighting Emitting Diode 88 Watts	534	29	3.82	0	0	$3.82	13,762	$3.21	19.1%	300	2,206	0.880	264.186	
Lighting Emitting Diode 92 Watts	535	31	4.09	0	0	$4.09	0	$3.37	21.4%	0	0	0.920	0.000	
Lighting Emitting Diode 105 Watts	536	35	4.61	0	0	$4.61	0	$3.84	20.0%	0	0	0.105	0.000	
Lighting Emitting Diode 170 Watts	537	57	7.51	0	0	$7.51	0	$6.24	20.3%	0	0	0.170	0.000	
Lighting Emitting Diode 110 Watts	539	37	4.88	0	0	$4.88	6,283	$4.05	20.4%	107	1,065	0.110	11.802	
Lighting Emitting Diode 65 Watts	540	22	2.90	0	0	$2.90	10,950	$2.40	20.7%	315	1,875	0.650	204.525	
Lighting Emitting Diode 55 Watts	541	18	2.37	0	0	$2.37	5,809	1.99	19.1%	204	931	0.550	112.347	
Lighting Emitting Diode 83 Watts	542	28	3.69	0	0	$3.69	3,746	3.07	20.2%	85	629	0.830	70.214	
Lighting Emitting Diode 48 Watts	543	16	2.11	0	0	$2.11	1,881	1.77	19.2%	74	303	0.830	61.652	
Lighting Emitting Diode 72 Watts	544	24	3.16	0	0	$3.16	12,049	2.62	20.6%	318	2,059	0.830	263.732	
							59,310			1,573				
Light Emitting Diode (P&E/C)														
LED Sat-48-44W	615	15	1.98	0	7.85	$9.83	457,398			3,878		0.440	1,706.202	
LED Sat-48-55W	616	18	2.37	0	7.85	$10.22	130,870			1,067		0.550	586.934	
LED Sat-48-74W	617	25	3.30	0	7.85	$11.15	737			6		0.740	4.079	
LED Sat-48-87W	618	29	3.82	0	7.85	$11.67	35,719			255		0.870	221.915	
LED Sat-72-65W	619	22	2.90	0	10.41	$13.31	716,904			4,489		0.650	2,917.789	
LED Sat-96-88W	620	29	3.82	0	11.77	$15.59	134,566			719		0.880	633.005	
LED Sat-96-110W	621	37	4.88	0	11.77	$16.65	107,525			538		0.110	59.200	
LED Sat-96-173W	622	58	7.65	0	11.77	$19.42	141,559			607		0.173	105.092	
							1,725,280			11,559				
TOTALS							**$23,774,902**			**143,496**	**$556,591**		**28,662.625**	**43.992**

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

SCHEDULE 11

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2012

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2012 New Proposed Rates	2012 New Proposed Revenue	2011 Current Rates	Percent Change	2012 (YA) Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
			Calculation of Power & Energy Rate :											
Miscellaneous Small Loads Rate			**Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load**											
Demand Charge	$/kW	**8.505**												
			Photocell Operation (4000 burning hours per year)											
Block 1 Energy			Demand Charge $/kW (annual)			10.221	$122.65							
Base cost of fuel	¢/kWh	4.816	Energy Charge :											
			1st Block : 1st 200 kW.h											
Non-fuel	¢/kWh	4.910	(annual)		2,400	0.11688	280.51							
			2nd Block : All additional											
AA	¢/kWh	-	(annual)		1,600	0.07760	124.16							
BA	¢/kWh	-					$527.32							
Total Energy Charge, block 1 (first 200kWh *	¢/kWh	**9.726**												
			Rate per kW.h		4,000		**$0.1318299**							
Block 2 Energy														
Base cost of fuel	¢/kWh	4.816	**Continuous Burning (8760 burning hours per year)**											
Non-fuel	¢/kWh	1.641	Demand Charge $/kW (annual)			10.221	$122.65							
AA	¢/kWh	-	Energy Charge :											
			1st Block : 1st 200 kW.h											
BA	¢/kWh	-	(annual)		2,400	0.11688	280.51							
			2nd Block : All additional											
Total Energy Charge, block 2	¢/kWh	**6.457**	(annual)		6,360	0.07760	493.54							
							$896.70							
			Rate per kW.h		8,760		**$0.1023625**							

ELI 2P-RTP REVISIONS

1.0 Introduction

In its letter dated January 25, 2011, regarding the Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP) Tariff 2010 Annual Report, the Board provided the following:

> The Board has reviewed this annual ELI 2P-RTP report and notes that NSPI is not proposing revisions to the tariff at this time. However, the Board anticipates that the issues which have been identified for further review will be addressed when NSPI files its next GRA.

NSPI is proposing revisions to the ELI 2P-RTP Tariff. Included in this submission is a brief background to the Tariff since its introduction in 2006 and a description of the changes requested by NSPI.

2.0 Background

The ELI 2P-RTP tariff was approved on October 27, 2006 following a public hearing[1] to replace the Extra Large Economic Interruptible Rate (ELIIR) that was considered by its customers to be unworkable due to the frequency and duration of the calls for load reduction. The approved tariff was predicated on three distinct ratemaking proposals made for the Board's consideration by StoraEnso[2] and Bowater Mersey (SEB)[3], NSPI and Dr. Stutz. The three rates differed considerably in terms of the proposed cost responsibilities for this class and its rate design. The UARB approved with some modifications the 2P-RTP-based rate design originally proposed by SEB.

[1] In the Matter of a Hearing to Establish a Rate to Replace Nova Scotia Power Incorporated's Extra Large Industrial Interruptible Rate- NSUARB-NSPI-P-883

[2] Now NewPage Port Hawkesbury.

[3] Now NPB.

The ELI 2P-RTP is a priority interruptible rate with hourly pricing signals designed to provide customers with power cost savings through load shifting. The rate has two distinct pricing components.

1. Customer Baseline (CBL) Base Cost Rate and

2. Debit/credit mechanism associated with load increases or reductions from the CBL.

The CBL Base Rate component follows conventional utility ratemaking practice and is subject to change only in GRA proceedings. The CBL is set annually in October based on consumption during the previous twelve months subject to adjustments for anomalies and factors which are expected to affect load for the next year such as change in market conditions, plant modifications, change in product line, etc.

The revenue responsibility associated with the CBL Base Rate component is determined by applying the Board-prescribed Revenue to Cost (R/C) Ratio for this class of 95% to its total cost responsibility as determined through the COSS. Embedded in the Cost of Service for this Class is credit for priority interruptibility.

The CBL Base Rate component includes two charges: the Customer Charge, designed to recover a portion of customer-related costs and the Standard Energy Charge (SEC), designed to recover all other costs of service as approved for recovery under the 95% R/C ratio.

The second pricing component of the ELI 2P-RTP Tariff, is the determination of debits and credits associated with load shifting from the customer's CBL. The debits and credits are charged/paid according to NSPI's hourly marginal cost of electricity.

In addition to the foregoing the 2P-RTP Tariff has certain billing provisions which make it a particularly complex rate to manage with unique features in the electric industry.[4] These include:

- CBL determination and administration
- Debit/Credit Mechanism as predicated on hourly Marginal Costs subject to tiered adjustments

At the time of the ELI 2P-RTP Hearing there was no empirical evidence available to assess the effectiveness of these provisions. Accordingly, in its Decision the Board provided:

> …the Board envisages that, if the 2P-RTP rate is subscribed by either Bowater or Stora Enso, there may be a need for the Board to review the terms and conditions (as opposed to the price) once experience is gained operating under the rate by NSPI and customers.
>
> For that reason the rate will continue to be below the line. The Compliance Order of the Board will include a provision that there be an annual review (not necessarily a hearing) of the new ELIIR rate which will not be a price adjustment, but rather will determine whether the rate is functioning fairly and efficiently with respect to its terms and conditions.

The performance of the ELI 2P-RTP rate with regard to the value provided to customers on the rate and recovery of costs by NSPI has been the subject of annual reports filed by NSPI with the UARB since 2007. Prior to 2009, NSPI reported two issues around unintended cost transfers from SEB to NSPI associated with imbalance between decremental and incremental costs and payments to and from customers under the credit debit mechanism:

- The tiered Mechanism of Providing Decremental Credits
- Incremental Energy Pricing

[4] To NSPI's knowledge no other utility allows its RTP customers to modify CBL in way it is permissible under the ELI 2P-RTP nor is the hourly marginal cost setting process used by other utilities.

The issues were not considered significant enough by NSPI at the time to warrant a revision to the tariff.

The introduction of the FAM in 2009 changed the ratemaking framework of NSPI and brought into focus additional issues not envisaged at the time the Tariff was approved in 2006. Specifically, the inclusion of ELI 2P-RTP debits and credits in the FAM, was determined to have potential to distort the value exchange between ELI 2P-RTP and other rate classes. This risk was sufficient for the Board to direct NSPI to produce a semi-annual report focused on the potential fuel cost transfer between ELI 2P-RTP customers and other FAM ratepayers.

In NSPI's 2009 and 2010 annual and semi-annual reports, the Company advised the Board of the following concerns:

- Failure to compensate the utility for non-fuel related costs due to CBL reductions
- Imbalances between credits and decremental fuel costs as accounted for under the FAM due to
  - SEC-based floor credit applied in the second and third tiers
  - Double counting for losses in the application of the SEC-based floor
  - Changing conditions in economic dispatch

In the FAM environment the under-recovery of non-fuel related costs has by far the most severe financial consequence for the utility. In a two year period of 2009 and 2010 NSPI under recovered $8.4 million of these costs as measured against the revenue benchmark set at the time of the 2009 Compliance Filing.

Year	2009 Compliance Filing		Actual		Unrecovered Fixed Costs	
	CBL Energy (GWhs)	Non-Fuel related revenues before customer charges (millions of $'s)	CBL Energy (GWhs)	Non-Fuel related revenues before customer charges (millions of $'s)	Amount (in millions of $'s)	%
2009	2,098.3	$46.9	1,873.5	$41.9	($5.0)	-11%
2010	2,098.3	$46.9	1,947.3	$43.5	($3.4)	-7%
Total	4,196.5	$93.8	3,820.7	$85.4	($8.4)	-9%
2011 FCST	2,098.3	$46.9	1,898.7	$42.4	($4.5)	-10%

3.0 Findings and Conclusion

The existing billing provisions for setting the CBL need improvement in rigor and transparency. Without this, unjustified cost transfers between NSPI and ELI 2P-RTP customers and EL-2P RTP and other FAM ratepayers can occur. Even at the times when debits and credits are cost-based, prolonged departures of actual load from the CBL level can produce fluctuation in costs of power for both FAM and ELI 2P-RTP ratepayers. As such they stand in the way of delivering on the tariff objectives set at the time of its design which included cost neutrality of this rate, fairness in apportionment of cost responsibilities among rate classes and effectiveness in yielding total revenue requirement of the utility under the allowable rate of return.

The current rules for adjustments to CBL levels during the year expose NSPI to risks in fluctuations in recovery of non-fuel costs which are much higher than is the case with large industrial customers under ratcheted demand charges[5]. However, not allowing CBL adjustment in situations of longer-term declines in actual load consumption also has undesirable consequences. It exposes FAM ratepayers to the cost of overestimated credits through the FAM AA mechanism. It also denies load shifting opportunities to 2P-RTP customers themselves at the times when they operate (consume power) at levels significantly below the CBL.

[5] Please see page 5 of the 2010 Annual ELI 2P-RTP Report.

NSPI has studied the effects of this Tariff carefully, and has reviewed the CBL related practice and tariffs of other jurisdictions, especially the leading utility in the 2P-RTP arena, Georgia Power. Based on this, NSPI proposes modifications to the following two operational aspects of the ELI 2P-RTP Tariff.

1. CBL Setting and Revision
2. Differences between Costs Avoided and Credits Paid due to
   a. the SEC-based floor in the second and third tiers and
   b. Double-counting for losses when the SEC-based floor is invoked for credit calculation purposes.

4.0 Proposed Changes to the Billing Provisions of the ELI 2P-RTP Tariff

4.1 Proposed changes to the administration of the CBL

In looking for solutions to these issues NSPI reviewed CBL administration practices at Georgia Power Company (GPC) which operates the largest 2P-RTP programs on the continent. Of particular interest to NSPI was an RTP program with an adjustable CBL. NSPI proposes to adopt this program with modifications appropriate to NSPI's circumstances. The proposed solution recognizes two distinct billing purposes of CBL:

1 establishing the base energy used in the calculation of the Base Cost portion of the bill and

2 setting the demand benchmark used in the determination of hourly debits and credits associated with load shifting

4.1.1 Nominal CBL level and Base Cost Rate Calculations

The nominal CBL level is proposed to be set at the time of a General Rate Application, unless significant and sustained changes at the customer's operations necessitate earlier change. This will give all stakeholders a chance to review a significant element in the calculation of their own rates and FAM adjustments. Should significant change be required between GRA hearings, NSPI and the customer will work together to develop new nominal CBL subject to the UARB approval. In the event no consensus is reached between the customer and NSPI, the matter will be passed for resolution to the UARB.

The CBL Base Cost calculations are proposed to be based on the nominal CBL. The nominal CBL will also be used for operational load shifting purposes with the exception of the times when temporary CBL adjustments are made as discussed in the following section.

4.1.2 Temporary CBL Adjustments for load shifting purposes

Should events beyond customer's control, such as lack of raw material, temporary plant modifications, lack of market or labour related issues, lead to temporary reduction in customer's power consumption, the customer may request that NSPI set an operational CBL ($CBL_{\mathbf{op}}$). The $CBL_{\mathbf{op}}$ would be distinct from the nominal CBL and would be solely for the operational purposes of load shifting for the duration of such events. Under such circumstance the nominal CBL would continue to be used for Base Cost bill calculation purposes.

4.1.2.1 Operation of the Debit/Credit Mechanism during temporary CBL adjustments

NSPI proposes to credit the customer for the amount of reduced CBL energy, from nominal to temporary operational level, at a forecasted average unit avoided cost subject to a constraint. NSPI proposes to set the lower and upper limits to the pricing credit at 90% and 110% of the Standard Energy Charge, respectively.

Load fluctuations from the operational CBL will be subject to the regular debit/credit mechanism. RTP prices will apply to the differences between the customer's actual load and the **CBL_{op}**. The hourly 20 minute ahead MC will be determined under the premise that the system load that gives rise to the MC is predicated on adjusted CBL load.

4.1.2.2 Risk Mitigation for FAM Customers

The proposed limits to the pricing credit for reduced CBL energy at the times of temporary CBL adjustments represent a solution specific to the situation of NSPI. The only two ELI 2P-RTP customers, being also the two largest customers on the system, have a unique ability to significantly affect the system fuel costs paid for by the FAM ratepayers through the inclusion of the ELI 2P-RTP debit/credit mechanism in the FAM. The proposed limits to the pricing credit are designed to find the right balance between risk exposure of the FAM ratepayers and ELI 2P-RTP customers. The mechanism will tend to reduce cost fluctuations to both groups of ratepayers.

4.2 The Floor in the Credit Mechanism and Double Crediting for line losses

In the current ELI 2P-RTP tariff the SEC is returned if the credit portion of the marginal costs is lower than the SEC. The credit paid is more than the avoided fuel costs. It also double-credits line losses as line losses are embedded in the SEC and once again in the credit calculation multiplier of 1.02. The credit floor should be lowered to a credit equivalent to the fuel contribution portion of the SEC.

5.0 Summary

The revisions proposed by NSPI will improve the efficiency and fairness of the ELI 2P-RTP Tariff. The recommendations adhere to sound ratemaking principles and minimize undue additional costs and risks to all customers, while reducing the probability of under-recovery of non-fuel related costs.

NSPI respectfully requests the UARB approve the ELI 2P-RTP CBL rate revisions as proposed by the Company in Appendix A.

APPENDIX A

PROPOSED REVISIONS TO THE ELI 2P-RTP TARIFF

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP, Adjustable CBL)

AVAILABILITY:

1. This tariff is available to NewPage Port Hawkesbury Ltd (NewPage), ~~customer load formerly served under the Extra Large Industrial Interruptible Rate (ELIIR) and 2P-RTP tariffs, specifically that of StoraEnso Port Hawkesbury Ltd (StoraEnso),~~ and Bowater Mersey Paper Company Ltd (Bowater) for energy other than presently served ~~load 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 tariff must accept priority supply interruption, meaning that customers on this tariff are interrupted after GR & LF ~~rate~~ tariff customers, and in advance of Interruptible Rider customers.

4. ~~This tariff cannot be taken in conjunction with the Extra High Voltage Time of Use Real Time Pricing Tariff (Rate Code 36)., as well as the ELIIR-2 tariff, is an alternative replacement tariff for the former ELIIR rate. Once having selected this tariff, the customer is no longer eligible for the ELIIR-2 tariff.~~ Once on this tariff, the customer must commit to taking service under this rate for a minimum of twelve months.

5. This tariff cannot be taken in conjunction with the Extra High Voltage Time-of-Use Real Time Pricing Tariff (Rate Code 36)~~1P-RTP rate~~.

CHARGES:

Customer Charge

EFFECTIVE: ~~**JANUARY 1, 2010**~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

The monthly customer charge under this tariff is $20,700.00 per month, per customer.

EFFECTIVE: ~~**JANUARY 1, 2010**~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Standard Energy Charge

The ~~s~~Standard ~~e~~Energy ~~c~~Charge (SEC), before accounting for shifting credits or additional charges, is 7.109~~6.187~~ cents per kWh. This charge will apply to all Customer Baseline Load (CBL) energy, regardless of actual consumption.

~~The energy charge is calculated using NSPI's approved Cost of Service Study (COSS) for the load forecast to be served under the ELIIR-2 and ELI 2P-RTP tariffs combined.~~

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.

Changes to Rate Components

The customer charge and standard energy charge of this tariff shall be subject to change as approved by the UARB following general rate applications by the Company. ~~For operational purposes, the annual CBL for each customer is reset for each calendar year.~~

RATE MECHANISM:

The intent of this rate is to create a mechanism enabling customers to gain benefit equal to the

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

benefit created by altering load usage in accordance to hourly pricing signals.

The customer will be billed based on a pre-determined CBL at the SEC~~Standard Energy Charge~~, regardless of energy actually taken during a billing period, with credits based on reduction from the CBL (decremental energy)~~ taken below the CBL~~ and costs added for energy taken above the CBL (incremental energy).

Incremental and Decremental energy deviations from the CBL will be billed/credited based on the 20-minute ahead marginal cost, as posted on NSPI's RTP website, adjusted according to the schedule stipulated in the Decremental Rebate section of this tariff.

Order in which Rates are Applied

Customers may elect to utilize other rates below the ELI 2P-RTP. In such case, the customer will make written request to the Company, specifying the MW level above which ELI 2P-RTP is to apply. Such changes will only be applied to the next full calendar year of billing.

With respect to the "stacking order" under which customers taking multiple rates are billed, no other rate may be taken above this rate.

DEFINITIONS:

Pricing Period

Each hour of the day is a distinct pricing period, the day starting at the 00:00:01, the first hour ending at 01:00:00. The applicable 20 minute ahead marginal price as posted on the RTP website will apply for each such period.

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Customer Baseline Load (CBL)

This is a flat line load shape used for the operational purpose of calculating hourly Incremental Load (IL) and Decremental Load (DL). The CBL level (in MW) is to be calculated as the average hourly demand of the customer's annual forecast total energy requirement (excluding system losses) from the Company. The CBL levels will ordinarily be set during General Rate Applications based on the test year load expectations as proposed by the participating customers and agreed to by NSPI subject to UARB approval. In the event significant and permanent changes in customer consumption take place in between GRA proceedings, the nominal CBL as agreed to by the customer and NSPI, can be reset subject to UARB approval. In the event there is no consensus between NSPI and the customer on a new nominal CBL the matter will be referred to the UARB for resolution. The CBL will reflect the reductions for normal annual maintenance periods and ~~.in effect from January 1st to December 31st of each year, and~~will be calculated according to the following formula:

$$\frac{\text{Forecast total test year energy requirement from the Company}}{\text{(Total number of hours in rate year)} - \text{(Total hours of major scheduled maintenance*)}}$$

*major scheduled maintenance as defined within this tariff

Unless specifically stated, the term "CBL" will refer to the nominal ~~annual~~ CBL as determined~~calculated~~ above. A temporary CBL level set during reductions in production will be referred to as the "operational CBL" **(CBL_{op})** -as defined below.

Operational CBL (CBL_{op})

This is a temporary CBL set during a period during which the customer encounters conditions that will result in a reduction of production that is not under his control, such as the lack of raw material, plant modifications, lack of market or labour related issues. Credits and debits will be

EFFECTIVE: ~~JANUARY 1, 2010~~

Formatted: Font: Bold, Italic

Formatted: Font: Not Bold

Formatted: Font: Times New Roman Bold, Subscript

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

based on the~~is~~ CBL_{op} level during this period. The customer will nominate an estimated provisional ~~operational~~ CBL_{op} level for the period. The provisional CBL_{op} level will be adjusted after the event based on the average energy taken during this period. Customers will be compensated for the fuel savings associated with the difference between the CBL and the CBL_{op}~~.~~ **at the forecast average unit avoided cost associated with this load reduction.**

Formatted: Font: Bold, Italic

Formatted: Font: Not Bold

Lower ELI 2P-RTP Threshold (LET)

This is the forecast threshold which defines the MW level above which ELI 2P-RTP is to be taken. The LET will be Ø if no other rates are to be used below ELI 2P-RTP. For Bowater, the LET is 42.0 MW when forecast energy is to be billed only under the Mersey Agreement and the ELI 2P-RTP tariff.

Forecast ELI 2P-RTP Energy Requirement

Forecast ELI 2P-RTP energy requirement from the Company is determined using the test year forecasting methodology for large industrial customers.~~customer's actual annual energy requirement above the LET (excluding system losses) from the Company for the Reference Period.~~

~~**Reference Period**~~

~~The Reference Period for use in determiningproducing the Forecast ELI 2P-RTP Energy Requirements is the previous 12 month period preceding the filing of a General Rate Application. Deviations from the Reference Period energy usage as adjusted for anomalies that occurred during the reference period must be substantiated by participating customersending September 30th of each year, subject to any correction for anomalies, as agreed between the Company and the customer. The Company shall provide the customer, on or before the 3rd normal working day of October each year, their previous 12 month energy consumption.~~

EFFECTIVE: ~~JANUARY 1, 2010~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

~~On or before the 15th day of October each year, the customer shall provide the Company, in writing, the proposed CBL for the subsequent calendar year. This submission shall include justification for the proposed CBL, including the anticipated dates and durations of the major scheduled maintenance periods. Energy reductions during periods in which an operational CBL is in effect will be compensated in the determination of the CBL for the upcoming year.~~

~~The parties will diligently, and in good faith, attempt to reach agreement. NSPI will have until October 31st in which to accept or reject the proposal in writing, with stated reasons for its rejection. In the event of disagreement, either party may refer the matter to the UARB for resolution, with the request for an expedited decision on the issues between the parties.~~.

Major Scheduled Maintenance Periods

Prior to the General Rate Case Application~~start of each calendar year~~, the customer will provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. If the customer and the Company are unable to agree on periods of major scheduled maintenance, the matter will be referred to the UARB.

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.

During periods of major scheduled maintenance, the CBL will be reduced accordingly to match the operating conditions of the plant. Such events will be treated as cutouts and will not affect the CBL for the subsequent year.

Formatted: Footer, Don't keep with next, Don't keep lines together

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

Marginal Cost (MC)

The MC will be the 20-minute ahead forecast of hourly marginal fuel and variable O&M cost in any hour, excluding any impacts of electricity exports, but including imports when they impact marginal costs. The MC forecast for each hour will be calculated by NSPI based on in-province load requirements. The load level(s) assumed for customers on the ELI 2P-RTP tariff will be the CBL value.

Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each day, hourly price forecasts for each hour of the next seven days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as possible after they occur.

The actual price used for billing purposes will be the MC, adjusted as stipulated in the Decremental Rebate section of this tariff.

Decremental Load (DL)

This is the hourly energy calculated as the difference between the CBL and the actual demand when actual demand is less than the CBL. When other tariffs are used below ELI 2P-RTP, DL in any hour is limited to the amount available between the LET and the CBL.

Decremental Rebate (DR)

The Decremental Load (DL) each hour, is multiplied by the MC, or a fraction of the MC as defined below, adjusted for losses, in that hour, and summed to produce the Decremental Rebate

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP) Adjustable CBL

Formatted: Font: Bold, Italic

(DR).

DL will be credited according to the following schedule:

- The credit for decrements, up to 30 MW for Bowater, and 75 MW for ~~StoraEnso~~ NewPage will be at -MC as defined by this tariff.
- For the next 10MW for Bowater, and 30 MW for ~~StoraEnso~~NewPage, the credits for decrements will be the greater of:
  - 80% of the MC; and
  - the ~~ELI 2P-RTP~~fuel related cost component of the SEC~~Standard Energy Charge~~
- For further decrements in excess of the above amounts the credit will be the greater of:
  - 60% of MC; and
  - the ~~ELI 2P-RTP~~fuel related cost component of the SEC~~Standard Energy Charge~~

Decremental Load eligible for DR is limited to 20% of the customer's annual CBL energy for the operating year. Once this limit is reached for the year, no further shifting rebates will be applied. Incremental load taken above the CBL will continue to be charged using incremental charges.

Incremental Load (IL)

This is the hourly energy calculated as the difference between the actual load and the CBL whenever the actual load exceeds the CBL.

Incremental Charges (IC)

The Incremental Load (IL) each hour, multiplied by the MC, adjusted for losses, in that hour, and summed to produce the Incremental Charge (IC).

Losses Adjustment:

EFFECTIVE: ~~JANUARY 1, 2010~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

A 2% adjustment to metered energy will be applied to incremental and decremental deviations from the relevant CBL level when calculating incremental costs and credits. In instances where the fuel related cost component of the SEC~~Standard Energy Charge~~ is credited in the second and third tiers of DR, the Line Loss Adjustment will not apply. ~~determine requirement including system losses. This Loss adjustment will be applied in determining the IL and the DL.~~

Incremental Export Benefit Credit

Customers who take service under this rate will be given an Incremental Export Benefit Credit (IEBC) defined as follows:

IEBC = (Lesser of Customer's Monthly DL or NSPI's Actual Exports calculated monthly) x NSPI's Average Export Margin in the month

However, in no case shall the total annual IEBC exceed 15% of NSPI's total actual annual export margin.

CBL Base Cost (CBL_{bc})

The monthly CBL_{bc} is calculated by multiplying the actual ELI 2P-RTP energy under the nominal~~annual~~ CBL level as adjusted only for supply interruptions called and annual maintenance periods included in the CBL calculation, in each hour of the billing period by the SEC~~applicable Standard Energy Charge~~.

Bill Calculation:

At the end of each month:

EFFECTIVE: ~~JANUARY 1, 2010~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

Total Bill = CBL_{bc} + Incremental Charges – Decremental Rebates - Incremental Export Benefit Credit + Customer Charge.

Applicable Energy Charges, rebates, penalties, and adjustments will be calculated by the Company and indicated on the customer's monthly bill.

SPECIAL CONDITIONS:

ADJUSTABLE CUSTOMER BASELINE LOAD (CBL):

~~**Modification of Existing CBL**~~

~~If an existing ELI 2P-RTP customer undertakes significant physical plant modification, (as signified by a specific capital expenditure above and beyond normal annual capital spending) or other material change (such as a change in product line) the Company or the customer may propose suitable adjustments to the CBL.~~

~~In the event of significant load reductions that have not been reflected in the CBL (such as plant shut downs, labour issues or any other reason), the CBL will be lowered accordingly or by agreement the rate may be suspended altogether until the customer returns to normal operations.~~

~~If the customer and NSPI cannot agree on any of the above modifications to the CBL the matter will be submitted to the UARB for adjudication.~~Temporary CBL Adjustments

The customer's nominal ~~annual~~ baseline load (CBL) is developed under the terms and conditions of this tariff as stated above. In instances where the customer is compelled to reduce production because of market conditions, labour issues, lack of raw materials or due to plant modifications in progress, customers may nominate a lower provisional operational CBL for the duration of the full or partial shut down.

EFFECTIVE: ~~**JANUARY 1, 2010**~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

A customer requiring ~~to set~~ a lower operational CBL for a limited period will notify NSPI of the expected average energy requirement for the reduced production period. This energy will be used to set the provisional operational CBL during the event. The provisional operational CBL will be set by dividing estimated energy requirement during the period by the estimated duration (in hours) of the reduction. At the conclusion of the reduction period the actual energy used during the period will be used to true up the provisional CBL_{op} ~~provisional operational CBL~~ level for billing purposes.

Credit for the energy between the nominal~~annual~~ CBL and ~~temporary~~ operational CBL

Formatted: Font: Bold

Formatted: Font: Bold

For the period in which ~~During the period in which~~ the operational CBL is effective, the customer will continue to pay the ~~normal~~ CBL base cost associated with their nominal ~~annual~~ CBL ~~level~~. NSPI will calculate the average forecast avoided cost associated with the CBL reduction. The customer will be credited at the average forecast avoided unit cost, subject to limitations, for the difference between the nominal~~rmal~~ and operational CBL for the duration of the reduction.

The avoided cost credited for the CBL reduction will be no more than 110% and no less than 90% of the SEC~~Standard Energy Charge~~.

The Two-Part Real Time Pricing mechanism will operate for incremental and decremental deviations from the operational CBL.

The operational CBL applies only for the ~~period~~ stipulated period.

Use of Self-Generation

Unless existing customer-owned generation is to be retired, for purposes of determining forecast CBL energy, the continued use of such generation is to be appropriately accounted for in the

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

customer's CBL energy requirement. Such self-generation shall continue to be used in a normal fashion. Beyond this, it is expected that customers will use their own existing generation in whatever fashion they see as appropriate.

Should a customer cease to generate energy the CBL will be adjusted by the average energy generated in the most recent year of normal operation of the generator including all energy usage estimated attributable to the auxiliary equipment associated with the operation of the boiler and turbine set.

Supply Interruption:

This tariff is interruptible for supply reasons. The customer will reduce ~~-~~ its available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company. 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.

Supply Interruption calls will be made to all customers taking energy under this tariff ~~and the ELIIR-2 tariff,~~ 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 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.

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)

EFFECTIVE: ~~**JANUARY 1, 2010**~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

Where:

"A" is any residual customer demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the 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.

The penalty charge for each failure shall be twice the cost of the appropriate billing as per this rate, for the total load subscribed under this rate. Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt. ~~decision pending.~~

Formatted: Font color: Blue

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.

EFFECTIVE: ~~JANUARY 1, 2010~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

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. ~~Extra Large Industrial Interruptible Rate-2, and~~ ELI 2P-RTP Rate
3. Interruptible Rider to the Large Industrial Rate.

In recognition that this tariff will receive interruption calls in advance of Interruptible Rider customers, the ELI 2P-RTP tariff will receive an interruptible credit (as determined in NSPI's COSS) that is 15% higher than the credit provided to Interruptible Rider customers for supply interruptibility.

Suspension of 2P-RTP Billing Mechanism

The Rate will be suspended during any period in which the customer's load is reduced due to a disruption in the supply of electricity to the customer because of an interruption call ~~or NSPI~~due to system conditions. The suspension shall apply until such time as the customer has received permission from the Company to resume operations.

The energy lost under the CBL will be estimated by the customer for the specific period from the start of the disruption to the time that NSPI notifies the customer that it can resume operation. An amount equivalent to the estimated lost energy, taken above the CBL immediately following the disruption, will be charged at the ~~Standard~~ Energy Charge rather than at IC.

If the customer and NSPI cannot agree on the amount of energy lost, the matter will be submitted to the UARB for adjudication.

EFFECTIVE: ~~JANUARY 1, 2010~~

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

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.

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.

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:

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)
Adjustable CBL

Formatted: Font: Bold, Italic

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

Formatted: Line spacing: 1.5 lines

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.

Special Consideration for Customer Purchasing Own Fuel

At the customer's option, the customer and NSPI shall use best efforts to enter into physical and/or financial purchases or hedges, the settlement of which shall be credited or charged to the customer's account. It is understood that the execution and settlement of these arrangements shall, under no circumstances, affect the rates or revenue requirements charged to the Company's other customers.

2012 REVENUE INCREASE ANALYSIS (Includes DSM)

Rate Classes	Sales (GWh's)	2012 Revenue at current rates before cost adjustment clauses	2011 FAM AA	2011 FAM BA	2011 DCRR	Revenue at current rates including 2011 AA/BA and 2011 DCRR	Proposed Revenues 2012 Before Riders			AA Component				BA Component				DCRR Component				DCRR BA Component				2012 Revenue reflective of all FAM components and DCRR		
							Amount	Increase	Increase (%) over Total Cost of Power	2011 Amount	2012 Amount	2012 Net Impact	Increase (%) over Total Cost of Power	2011 Amount	2012 Amount	Variance	Increase (%) over Total Cost of Power	2011 DCRR	2012 DCRR	2011 Net Impact	Increase (%) over Total Cost of Power	2011 DCRR BA	2012 DCRR BA	2011 Net Impact	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
ATL																												
Residential	**4,372.5**	**$564,213,388**	**$7,070,030**	**$4,788,793**	**$20,004,640**	**$596,076,852**	**$606,735,427**	**$42,522,039**	**7.1%**	**$7,070,030**	**0.00**	**($7,070,030)**	**-1.2%**	**$4,788,793**	**$18,977,732**	**$14,188,939**	**2.4%**	**$20,004,640**	**$22,772,456**	**$2,767,816**	**0.5%**	**$0**	**$0**	**$0**	**0.0%**	**$648,485,615**	**$52,408,763**	**8.8%**
Small General	219.5	$29,390,859	$358,440	$274,450	$1,550,533	$31,574,282	$31,138,195	$1,747,336	5.5%	$358,440	0.00	($358,440)	-1.1%	$274,450	$1,071,934	$797,484	2.5%	$1,550,533	$1,482,661	($67,873)	-0.2%	$0	$0	$0	0.0%	**$33,692,790**	$2,118,507	6.7%
General Demand	2,534.0	$273,211,579	$3,242,529	$2,813,995	$11,775,576	$291,043,678	$290,881,040	$17,669,461	6.1%	$3,242,529	0.00	($3,242,529)	-1.1%	$2,813,995	$11,624,973	$8,810,979	3.0%	$11,775,576	$10,374,675	($1,400,901)	-0.5%	$0	$0	$0	0.0%	**$312,880,689**	$21,837,010	7.5%
Large General	394.4	$35,986,765	$374,128	$441,352	$2,006,137	$38,808,382	$38,698,914	$2,712,149	7.0%	$374,128	0.00	($374,128)	-1.0%	$441,352	$1,833,732	$1,392,380	3.6%	$2,006,137	$1,043,338	($962,799)	-2.5%	$0	$0	$0	0.0%	**$41,575,984**	$2,767,602	7.1%
Total Commercial	**3,147.8**	**$338,589,203**	**$3,975,097**	**$3,529,797**	**$15,332,246**	**$361,426,343**	**$360,718,149**	**$22,128,946**	**6.1%**	**$3,975,097**	**0.00**	**($3,975,097)**	**-1.1%**	**$3,529,797**	**$14,530,640**	**$11,000,843**	**3.0%**	**$15,332,246**	**$12,900,674**	**($2,431,573)**	**-0.7%**	**$0**	**$0**	**$0**	**0.0%**	**$388,149,462**	**$26,723,119**	**7.4%**
Small Industrial	261.9	$26,281,215	$303,562	$283,144	$521,795	$27,389,715	$28,261,903	$1,980,688	7.2%	$303,562	0.00	($303,562)	-1.1%	$283,144	$1,126,315	$843,171	3.1%	$521,795	$1,030,294	$508,499	1.9%	$0	$0	$0	0.0%	**$30,418,511**	$3,028,796	11.1%
Medium Industrial	512.9	$44,957,639	$495,236	$554,433	$1,470,054	$47,477,362	$48,345,880	$3,388,240	7.1%	$495,236	0.00	($495,236)	-1.0%	$554,433	$2,181,099	$1,626,666	3.4%	$1,470,054	$2,149,710	$679,656	1.4%	$0	$0	$0	0.0%	**$52,676,689**	$5,199,326	11.0%
Large Industrial	932.6	$70,390,764	$758,644	$919,006	$1,847,128	$73,915,542	$75,695,776	$5,305,012	7.2%	$758,644	0.00	($758,644)	-1.0%	$919,006	$3,937,047	$3,018,040	4.1%	$1,847,128	$2,172,441	$325,314	0.4%	$0	$0	$0	0.0%	**$81,805,264**	$7,889,722	10.7%
ELI_2PT - RTP	1,814.3	$113,492,502	$1,576,748	$2,165,643	$1,576,239	$118,811,132	$129,481,914	$15,989,412	13.5%	$1,576,748	0.00	($1,576,748)	-1.3%	$2,165,643	$7,529,206	$5,363,563	4.5%	$1,576,239	$1,562,320	($13,919)	0.0%	$0	$0	$0	0.0%	**$138,573,440**	$19,762,308	16.6%
Total Industrial	**3,521.8**	**$255,122,120**	**$3,134,190**	**$3,922,226**	**$5,415,215**	**$267,593,752**	**$281,785,472**	**$26,663,352**	**10.0%**	**$3,134,190**	**0.00**	**($3,134,190)**	**-1.2%**	**$3,922,226**	**$14,773,667**	**$10,851,441**	**4.1%**	**$5,415,215**	**$6,914,765**	**$1,499,550**	**0.6%**	**$0**	**$0**	**$0**	**0.0%**	**$303,473,904**	**$35,880,153**	**13.4%**
																						$0	$0					
Municipal	197.4	$17,586,797	$223,750	$206,396	$870,350	$18,887,293	$18,912,229	$1,325,432	7.0%	$223,750	0.00	($223,750)	-1.2%	$206,396	$868,630	$662,234	3.5%	$870,350	$828,132	($42,218)	-0.2%	$0	$0	$0	0.0%	**$20,608,991**	$1,721,699	9.1%
Unmetered	115.7	$25,301,915	$115,986	$140,161	$148,026	$25,706,088	$25,382,334	$80,419	0.3%	$115,986	0.00	($115,986)	-0.5%	$140,161	$532,987	$392,825	1.5%	$148,026	$190,662	$42,636	0.2%	$0	$0	$0	0.0%	**$26,105,982**	$399,894	1.6%
Total Other	**313.1**	**$42,888,712**	**$339,736**	**$346,557**	**$1,018,376**	**$44,593,381**	**$44,294,563**	**$1,405,851**	**3.2%**	**$339,736**	**0.00**	**($339,736)**	**-0.8%**	**$346,557**	**$1,401,616**	**$1,055,059**	**2.4%**	**$1,018,376**	**$1,018,794**	**$418**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$46,714,973**	**$2,121,593**	**4.8%**
Total ATL Classes	**11,355.2**	**$1,200,813,424**	**$14,519,053**	**$12,587,373**	**$41,770,478**	**$1,269,690,327**	**$1,293,533,611**	**$92,720,187**	**7.3%**	**$14,519,053**	**0.00**	**($14,519,053)**	**-1.1%**	**$12,587,373**	**$49,683,655**	**$37,096,282**	**2.9%**	**$41,770,478**	**$43,606,689**	**$1,836,211**	**0.1%**	**$0**	**$0**	**$0**	**0.0%**	**$1,386,823,955**	**$117,133,628**	**9.2%**
BTL (Electric)																												
GRLF	108.4	$6,725,686	$0	$0	$5,925	$6,731,611	$6,725,686	$0	0.0%	$0	0.00	$0	0.0%	$0	$0	$0	0.0%	$5,925	$7,358	$1,432	0.0%	$0	$0	$0	0.0%	**$6,733,043**	$1,432	0.0%
Mersey Additional Energy	179.9	$11,177,086	$162,370	$143,485	$123,597	$11,606,538	$11,177,086	$0	0.0%	$162,370	0.00	($162,370)	-1.4%	$143,485	$547,910	$404,425	3.5%	$123,597	$132,611	$9,014	0.1%	$0	$0	$0	0.0%	**$11,857,607**	$251,069	2.2%
Bowater Mersey	189.0	$9,279,726	$0	$0	$0	$9,279,726	$9,279,726	$0	0.0%	$0	0.00	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0		**$9,279,726**	$0	0.0%
Total BTL (Electric) Classes	**477.3**	**$27,182,498**	**$162,370**	**$143,485**	**$129,522**	**$27,617,875**	**$27,182,498**	**$0**	**0.0%**	**$162,370**	**0.00**	**($162,370)**	**-0.6%**	**$143,485**	**$547,910**	**$404,425**	**1.5%**	**$129,522**	**$139,968**	**$10,446**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$27,870,377**	**$252,502**	**0.9%**
LED SL Capital Costs			$0	$0	$0	$0	$1,314,415																			**$1,314,415**	$1,314,415	N/A
FAM classes	**11,535.2**	**$1,211,990,510**	**$14,681,423**	**$12,730,858**	**$41,894,075**	**$1,281,296,865**	**$1,304,710,697**	$92,720,187	7.2%	**$14,681,423**	**0.00**	**($14,681,423)**	**-1.1%**	**$12,730,858**	**$50,231,566**	**$37,500,708**	**2.9%**	**$41,894,075**	**$43,739,299**	**$1,845,225**	**0.1%**	**$0**	**$0**	**$0**	**0.0%**	**$1,398,681,562**	**$117,384,697**	**9.2%**
In Province Total	**11,832.6**	**$1,227,995,921**	**$14,681,423**	**$12,730,858**	**$41,900,000**	**$1,297,308,203**	**$1,322,030,524**	**$94,034,603**	**7.2%**	**$14,681,423**	**0.00**	**($14,681,423)**	**-1.1%**	**$12,730,858**	**$50,231,566**	**$37,500,708**	**2.9%**	**$41,900,000**	**$43,746,657**	**$1,846,657**	**0.1%**	**$0**	**$0**	**$0**	**0.0%**	**$1,416,008,747**	**$118,700,545**	**9.1%**
Export	33.9	$961,058	$0	$0	$0	**$961,058**	$961,058	$0	0.0%	$0	0.00	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0		**$961,058**	$0	0.0%
Total Electric Sales	**11,866.4**	**$1,228,956,979**	**$14,681,423**	**$12,730,858**	**$41,900,000**	**$1,298,269,261**	**$1,322,991,582**	**$94,034,603**	**7.2%**	**$14,681,423**	**0.00**	**($14,681,423)**	**-1.1%**	**$12,730,858**	**$50,231,566**	**$37,500,708**	**2.9%**	**$41,900,000**	**$43,746,657**	**$1,846,657**	**0.1%**	**$0**	**$0**	**$0**	**0.0%**	**$1,416,969,805**	**$118,700,545**	**9.1%**
Misc Revenue	815.6	$15,521,415	$0		$0	**$15,521,415**	$15,908,418	$0	**0.0%**	$0	0.00	$0	0.0%	$0	$0	$0	0.0%	$0		$0	0.0%	$0	$0	$0		**$15,908,418**	$387,003	2.5%
Grand Total	**12,682.0**	**$1,244,478,394**	**$14,681,423**	**$12,730,858**	**$41,900,000**	**$1,313,790,676**	**$1,338,900,000**	**$94,421,606**	**7.2%**	**$14,681,423**	**0.00**	**($14,681,423)**	**-1.1%**	**$12,730,858**	**$50,231,566**	**$37,500,708**	**2.9%**	**$41,900,000**	**$43,746,657**	**$1,846,657**	**0.1%**	**$0**	**$0**	**$0**	**0.0%**	**$1,432,878,223**	**$119,087,547**	**9.1%**

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~~NS Power's normal working hours.	$~~24~~26.00 standard charge
(b)	Connection or reconnection of electric service, whether metered or unmetered, to any premises after ~~the Company~~NS Power's normal working hours, if requested by the Customer and is not a reconnection for non payment.	$~~24~~26.00 standard charge plus $~~64~~69.00 charge for additional costs.
(c)	Reconnection of electric service, whether metered or unmetered, to any premises after ~~the Company~~NS Power's normal working hours, if requested by the Customer and is a reconnection associated with non payment.	$~~24~~26.00 standard charge plus $~~64~~69.00 charge for additional costs.
(d)	Connection or reconnection of electric service to any premises serviced by temporary service in accordance with these Regulations.	$~~24~~26.00 standard charge plus all other costs incurred by ~~the Company~~NS Power in connecting or reconnecting service
(e)	Disconnection-Seasonal Electric Service	$~~25~~27.00 standard charge
(f)	Returned Cheque Charge	$~~20~~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
(i)	Dispute Test Fee re satisfactory meter	$~~32~~34.00

REGULATION

7.1 SCHEDULE OF CHARGES

(j)	Standard Contribution for three-phase service 15 kW and under	$~~1,041~~1,121.00
(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~~NS Power
(l)	Service Charge for any miscellaneous requests.	Actual Costs incurred by ~~the Company~~NS Power
(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

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.

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.

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.

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	$ ~~97~~104.00
Greater than 1,000 amps	$ ~~97~~104.00

e) **Primary Services**

The fees for the inspection of a primary service (padmount, vault, etc.) shall be per installation. $~~124~~134.00

f) **Letter of Acceptance**

The fees for a Letter of Acceptance shall be .... $ ~~32~~35.00

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	$ ~~58~~62.00
$ 2,001 to $ 4,000	2	$ ~~117~~126.00
$ 4,001 to $ 6,000	2	$ ~~196~~210.00
$ 6,001 to $ 8,000	2	$ ~~246~~252.00
$ 8,001 to $ 10,000	2	$ ~~298~~294.00
$ 10,001 to $ 15,000	3	$ ~~390~~420.00
$ 15,001 to $ 25,000	3	$ ~~495~~533.00
$ 25,001 to $ 50,000	3	$ ~~716~~771.00
$ 50,001 to $ 100,000	3	$~~1,105~~1,073.00
$100,001 to $ 300,000	4	$~~1,690~~1,683.00
$300,001 to $ 500,000	5	$~~2,210~~2,103.00
$500,001 to $750,000	6	$~~2,860~~2,524.00
$750,001 to $1,000,000	8	$~~3,380~~3,365.00
+ $1,000,000	10	$~~3,901~~4,201.00 + 0.15% of cost in excess of $1,000,000

New Installations are subject to the following minimum inspection fees:

RESIDENTIAL-ALL INSTALLATIONS	$~~117~~126.00
COMMERCIAL/INDUSTRIAL INSTITUTIONAL	
Up to 100 AMPS	$~~117~~126.00
Over 100 to 400 AMPS	$~~298~~294.00
Over 400 to 800 AMPS	$~~390~~420.00
Over 800 to 1000 AMPS	$~~495~~533.00
Over 1000 AMPS	$~~716~~771.00

g) **Hourly Rate Inspections**

REGULATION

7.2 SCHEDULE OF WIRING INSPECTION FEES

Note: All fees are per inspection visit.

Normal Working Hours:

i)	For the first hour or fraction thereof	$ ~~57~~61.00
ii)	For each additional half-hour or fraction thereof..	$ ~~24~~26.00

Outside Normal Working Hours:
Extension of a regular work day (before or after)

i)	For the first hour or fraction thereof.......	$ ~~77~~83.00
ii)	For each additional half-hour or fraction thereof..	$ ~~33~~36.00

Weekends and Statutory Holidays:
Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:

i)	For the first hour or fraction thereof.......	$~~127~~137.00
ii)	For each additional half-hour or fraction thereof..	$ ~~46~~50.00

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.

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING 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~~NS Power.

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~~NS Power plus at 25% markup.

d) **Specialized Customer Analysis** will be the actual costs incurred by ~~the Company~~NS Power plus at 25% markup.

SCHEDULE OF LOAD RESEARCH CHARGES

		~~ONE-TIME~~	**~~BI-MONTHLY~~**	**~~MONTHLY~~** **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.		
	~~Single or Three Phase~~	~~300.00~~	~~11.11~~	~~5.45~~
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	~~61.00~~		$39.00
	Single Phase Service, Transformer Rated and Three Phase Service	~~245.00~~		$106.00
3.0	**~~Load Research Setup~~Recovery of Operational Charges**			$186.00
4~~3~~.0	**Load Research Setup**			$~~40~~43.00

Formatted: Font: 12 pt
Formatted: Justified
Formatted: Font: 12 pt
Formatted: Justified
Formatted: Font: 12 pt
Formatted: Font: 12 pt
Formatted: Centered
Formatted: Font: 12 pt
Formatted: Centered

REGULATION

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING AND ANALYTICAL CHARGES

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

6.0 **Specialized Analysis**

Hourly Rate	$~~99~~73.00